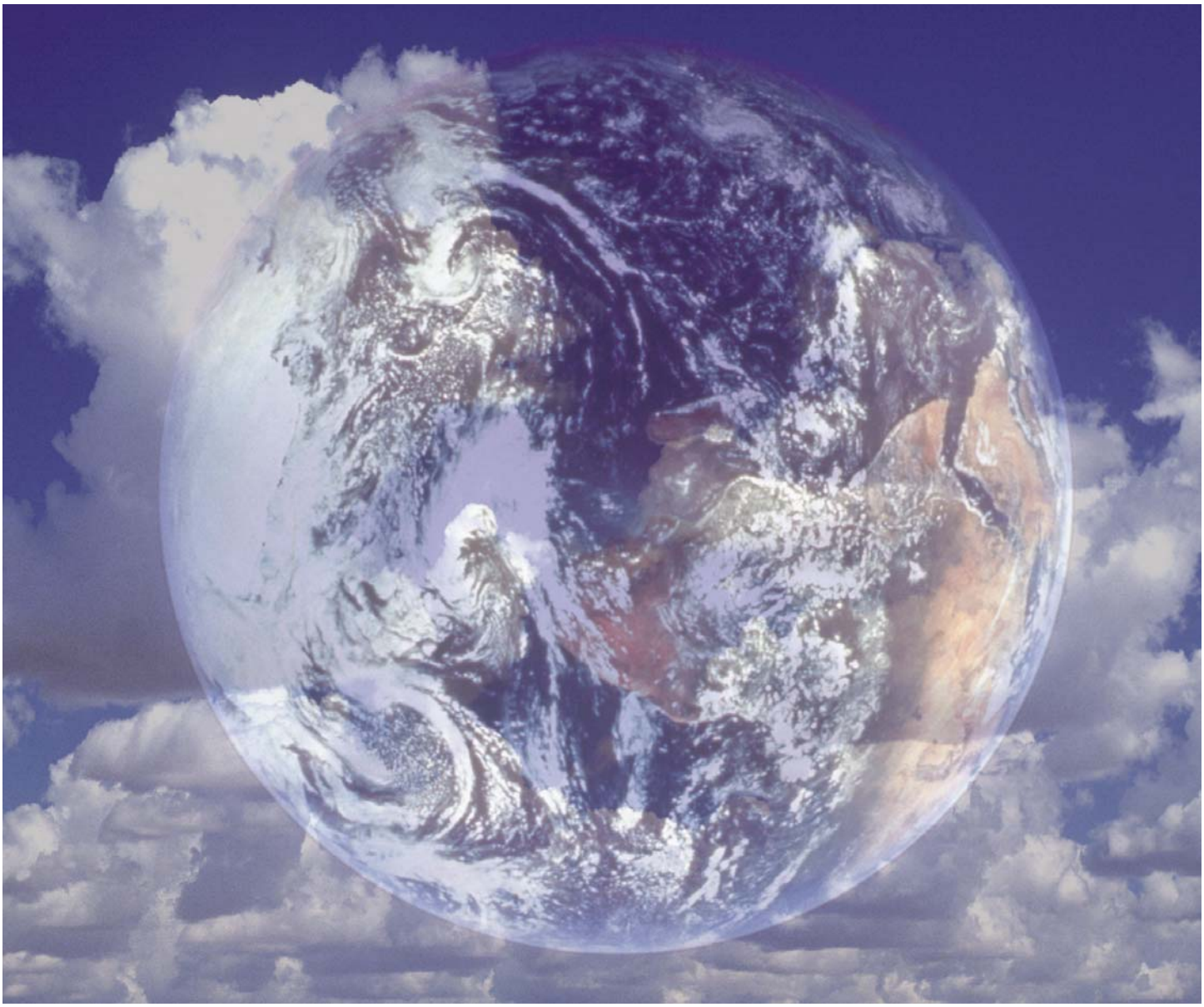
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Energy Efficiency Planning Guidebook

Energy Efficiency Initiative



Energy Efficiency Planning Guidebook

Energy Efficiency Initiative

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PRODUCT DESCRIPTION

Demand planning is an essential undertaking for utilities looking to understand and quantify the dispatchable resources associated with energy efficiency and demand response programs. Further, demand planning enables a utility to select the most appropriate, cost-effective suite of energy efficiency technologies, demand response technologies, and program delivery mechanisms for its unique market and operating conditions as well as the optimal level of investment. This guidebook reviews and explains a comprehensive process by which utilities can plan, design, execute, and evaluate energy efficiency and demand response programs. Utilities can apply this as a reference primer in the development or enhancement of energy efficiency plans and programs. It is intended for use by a broad cross section of utility energy efficiency, planning, and marketing professionals—from those new to the field to seasoned professionals.

Results & Findings

The guidebook draws upon fundamental principles and practices of demand-side management, as documented in seminal EPRI studies of the 1980s and 1990s and honed over decades of utility experience. Following a discussion of the broader market and regulatory context of energy efficiency, the guidebook reviews the key steps of the energy efficiency process:

- Setting strategic objectives
- Baseline forecasting
- Screening measures
- Sizing-up customer acceptance and response
- Estimating savings potential
- Program design
- Measuring cost-effectiveness
- Implementation and monitoring
- Evaluation, measurement, and verification (EM&V)

The implications of emerging energy efficiency and demand response technologies and market trends are also addressed.

Challenges & Objective(s)

Utilities today are impelled by multiple forces to pursue energy efficiency with a renewed sense of purpose, emphasizing compliance with proliferating state energy savings mandates, improving operational efficiency, and meeting public expectations to curb carbon emissions in order to arrest climate change. Yet utilities face challenges to realizing their energy efficiency potential, including the retention of core competency in planning as well as cost-effective design and execution of energy efficiency programs. With a large share of its workforce approaching retirement, the utility industry is bracing for staff turnover that will impact all operations, particularly demand-side management. The influx of new professionals to fill the ranks will need to quickly come up to speed on energy efficiency. Resources such as this guidebook can help by serving as a reference on what has been learned over decades of utility experience.

Applications, Values & Use

Utility energy efficiency, demand response planning, and marketing professionals can apply this guidebook as a reference primer in the development of new programs or enhancement of existing programs.

EPRI Perspective

EPRI has been a thought leader in energy efficiency since the advent of demand-side management, producing a seminal multivolume series on the subject in the mid 1980s and subsequent follow-on reports through the early 1990s. This guidebook revisits and updates these fundamental works with knowledge developed over the intervening years of utility energy efficiency activities. Utilities can apply this credible, independent, unbiased guidebook, which demystifies the process of demand and energy efficiency planning and provides step-by-step instructions and examples.

Approach

Guidebook developers first reviewed a comprehensive process by which utilities could plan, design, execute, and evaluate energy efficiency programs. They designed the guidebook to leverage seminal EPRI works on the subject and other literature in the field, along with insights borne of utility experience over the past two decades.

Keywords

Energy Efficiency
Demand Response
Demand-Side Management
Baseline Forecast
Evaluation, Measurement, and Verification (EM&V)
Program Design and Implementation
Dynamic Pricing

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1
ENERGY EFFICIENCY TODAY

Historical Perspective

Rapidly rising energy costs in the 1970s provided utilities and regulatory commissions with a strong impetus to impel consumers to conserve energy and manage peak loads. The driving forces were heightened inflationary pressures in the economy, cost over-runs on new power plants and rising oil prices. Utilities implemented a wide variety of conservation and load management programs.

These programs were largely ad hoc and reactive in nature and focused on providing information to customers. Relatively few utility personnel were involved in these programs and program funding levels were low. Not much effort was directed at quantifying the amount of energy that was actually saved by the programs.

The first generation of programs was succeeded in the 1980s by more carefully thought out second generation programs that operated under the banner of demand-side management (DSM), DSM programs were a formal approach that encompassed all actions on the customer side of the meter and were designed for the mutual benefit of customers and the utility.

EPRI, in conjunction with the Edison Electric Institute (EEI), helped develop methodologies, analytical tools and databases for designing, implementing, monitoring, and evaluating DSM programs. EPRI also developed a taxonomy of programs focused on five load shape objectives:

- Peak Clipping
- Strategic Conservation
- Load Shifting
- Valley Filling
- Strategic Load Growth

EPRI and EEI collaborated on the production of a five-volume report on all aspects of DSM, which began to resemble a new discipline within the broad rubric of public utility regulation.

Utilities invested substantial funding in DSM, in some cases encouraged by legislation and regulatory rulings that required them to spend a specific amount of their revenues on cost-effective DSM. Out of this effort evolved a comprehensive array of programs directed at a wide variety of customer segments. Several of them involved cash rebates to customers to encourage the purchase of efficient appliances and building systems. For the most part, these programs did not involve changes in rate levels or rate designs.

A typical program portfolio used one or more of the following mechanisms to achieve DSM objectives:

- Information/Education (mass media campaigns, targeted information)
- Services (audits, retrofits, training)
- Rebates (prescriptive or custom)
- Other financial incentives (financing, on-bill financing)
- Trade ally / upstream programs (builders, A/E firms, distributors)
- Performance contracting/shared savings

As DSM expenditures mounted, it became necessary to assess the cost-effectiveness of these programs. California's Standard Practice Manual for evaluating DSM programs was published, which featured five tests reflecting the viewpoints of participating customers, all ratepayers, non-participants, the utility, and society. Eventually, these tests were adopted around the country and the globe. In addition, statistical and engineering methods were developed to measure the impact of DSM programs and to redesign them if the impacts did not help the original objectives.

In 1993, EPRI published a report that synthesized the rapidly growing literature on the subject, "Principles and Practice of Demand-Side Management." This covered all the major steps for designing, implementing and evaluating DSM programs. This also turned out to be the year in which utility spending on DSM peaked at $2.74 billion a year, as shown in Figure 1-1.

In anticipation of restructuring, utilities began to divide their operations into strategic business units for generation, transmission and distribution, and as a consequence the DSM function often fell between the cracks and was neglected. Funding for DSM was also reduced because it tended to raise rates due to program costs and lost revenues, thereby hampering the competitiveness of incumbent utilities facing the prospect of new entrants vying for retail electricity market share.

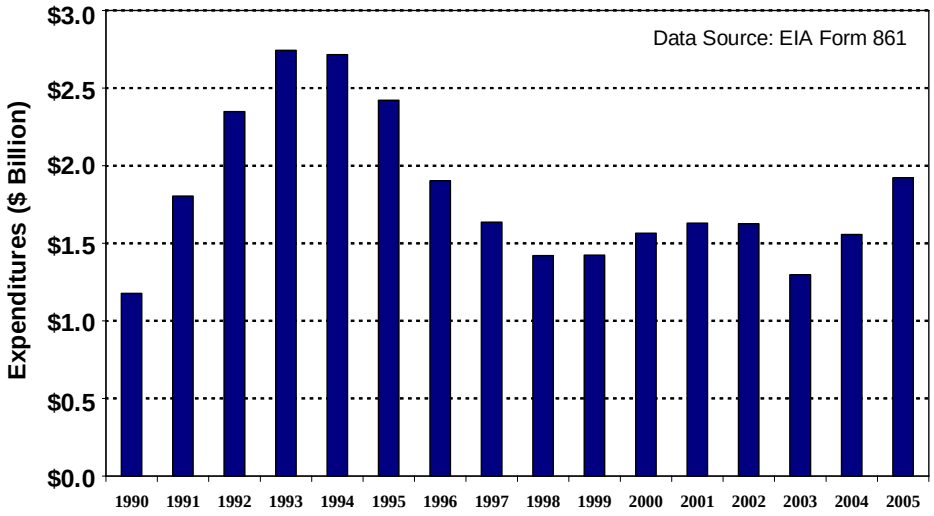


Figure 1-1
Annual DSM Expenditures, 1994–2005

This state of affairs continued until the turn of the century. With the exception of a few states such as California, Florida and New York, DSM had become a maintenance function for many utilities, with minimal staff assigned, few new programs initiated, and budgets a fraction of their early 1990s levels.

The New Policy Drivers

As the first decade of the 21st century nears a close, DSM—or "energy efficiency" as it is more commonly referred to today—is poised to make a comeback with a third generation of programs, due to a remarkable combination of events.

Restructuring has not panned out as the panacea that its proponents had expected, and rates are no lower in states that restructured than in states that did not restructure. Moreover, rates are not even lower in the restructured states than they were at the beginning of the process. States that had imposed rate freezes to facilitate competition are faced with significant price hikes as those freezes expire. Some utilities and state commissions are calling for outright re-regulation but there are significant legal and political reasons why that may be difficult to bring about.

Fuel costs are rising nationwide because of developments in world energy markets. Demand continues to grow, requiring the installation of new generation, transmission and distribution capacity. In addition, there is a need to replace significant portions of the nation's transmission and distribution infrastructure.

Rising demand for construction materials, driven largely by their use in China and India, has also made it more expensive to build power plants, transmission towers and distribution lines in the United States. Additional cost drivers include public resistance to building power plants and transmission lines, and delays in the siting and permitting process. Until recently, nowhere has public resistance to building large power plants been more pronounced than in the case of nuclear power. For many years, no new orders were placed for nuclear power plants, with the most recent nuclear plant having gone on line in 1996. [1]

The current conditions of rate shocks, concerns over reducing dependence on foreign energy supplies from politically unstable regions, and exhortations to reduce consumption are reminiscent of the 1970s. But there are two added dimensions to the current situation: (1) motivation to arrest the pace of climate change by burning less carbon; and (2) the need to manage peak loads.

Awareness of the link between greenhouse gas emissions and climate change seemed to reach a "tipping point" in public consciousness between 2005 and 2006, with the American public having now reached a consensus that action needs to be taken to reduce carbon emissions. The reduction of carbon emissions has emerged as a major driver for energy efficiency.

[1] U.S. Energy Information Administration (EIA). http://www.eia.doe.gov/cneaf/nuclear/page/analysis/nuclearpower.html.

Accordingly, states have followed suit with policies aimed at reducing carbon emissions. For example, California has passed legislation (Assembly Bill 32) that will roll back carbon emissions to 1990 levels by the year 2020. Following a Climate Change summit last summer, the governor of Florida issued an executive order (EO 07-127) on July 13, 2007 that sets specific limits for greenhouse gas emissions by electric utilities: 2000 levels by 2017; 1990 levels by 2025; and 80 percent of 1990 levels by 2050.

The compact fluorescent lamp and hybrid vehicle have become iconic symbols of energy efficiency and environmental consciousness embraced by influential celebrities and policymakers throughout the globe. The media continues to keep the issue alive with yet more forceful articles, television programs, and films. Many states have instituted renewable portfolio standards and similar standards for energy efficiency savings targets. Moreover, the emergence and growing acceptance of the ENERGY STAR® brand as a symbol of energy efficiency are signals that the "green conscious" lifestyle is moving from fringe to mainstream.

The second major difference today is the recognition by policy makers that, because it is very expensive to supply peak loads, it is important to provide price signals and incentives to customers that will encourage them to curtail peak usage beyond efforts to reduce overall consumption levels through energy efficiency. This has led to a new wave of "demand response" programs.

A Bird's Eye View of New Energy Efficiency Initiatives

California, the most populous state that often serves as a bellwether in many fields, has adopted an Energy Action Plan that specifies a "loading order of resources," which begins with energy efficiency, followed by demand response and renewables before moving on to conventional fuels.

In the Carolinas and the Midwest, Duke Energy CEO Jim Rogers has labeled energy efficiency the "fifth fuel" for meeting customer energy needs. Duke intends to meet half of its projected capacity need for 3,400 MW with energy efficiency, provided it gets the appropriate financial incentives (discussed further in Chapter 2). Not surprisingly, several advocacy groups have picked up on Rogers' term and taken it one step further to anoint energy efficiency as the "first fuel."

In the state of Florida, as mentioned earlier, Governor Charlie Crist has laid out an ambitious plan to transform Florida into California's chief ally in the fight against global warming. In addition to the executive order that sets targets for utility greenhouse-gas emissions, another executive order pledges that state government will lead by example in meeting strict energy conservation and greenhouse-gas standards for buildings the state owns, leases or builds, for products the state buys, and for state-owned vehicles.

In Virginia, the CEO of Dominion has concluded that the only way to meet the additional demand for 4,000 MW of power over the next ten years is through a combination of energy conservation, energy efficiency, and peak-load management programs along with a systematic program to add new generation facilities.

In Maryland, where electricity rates are rising by 50 percent, Governor Martin O'Malley has enacted an energy efficiency initiative called "EmPOWER Maryland" designed to reduce per capita electricity consumption in the state by 15 percent by the year 2015, an action that is expected to lower power costs by $1.8 billion. [2]

At a recent meeting of the Western Governors Association focusing on energy efficient buildings, Colorado Governor Bill Ritter called conservation and efficiency "the richest sources of new energy." Saying that, "The cheapest watt of electricity is the watt that isn't consumed at all. It's called the negawatt," Ritter declared, "This is true whether we're talking about compact fluorescent light bulbs, more efficient use of passive solar, or improved insulation and windows." He then went on to make a commitment to increase energy efficiency in the state by 20% by 2020. [3] Governor Jon Huntsman of Utah has gone even further, signing an executive order to achieve a 20% increase in energy efficiency by 2015.[4] Governor Bill Richardson of New Mexico recently signed into law a new energy efficiency bill that provides incentives to electric and gas utilities to reduce their customers' energy consumption, with a target of reducing forecasted consumption 10 percent by 2020.[5]

Energy efficiency now figures prominently in all state Climate Action Plans. Western states are leading in the construction of new ENERGY STAR® labeled homes, with Arizona, Nevada, and Texas alone accounting for half of the nation's total last year, and ENERGY STAR® accounting for 71% of all new home construction in Nevada in 2006.[6] More than 15% of new homes qualified for ENERGY STAR® status in California, Utah, and Hawaii. Arizona calculates that the net economic benefits of its Climate Action Plan, which includes both renewable energy and energy efficiency, at $5.6 Billion from 2007-2020. Such analyses support the assertion that addressing climate change and increasing economic growth are not mutually exclusive endeavors, since energy efficiency facilitates both. [7]

In the Canadian province of Ontario, $2 billion has been spent on energy efficiency programs since 2003. The province is pursuing energy efficiency to help customers save money on their utility bills and to help reduce greenhouse gases. In seeking to create a culture of conservation, the province has become the first jurisdiction in Canada to ban inefficient lighting by 2012.

Constraints Posed by Market Structure

In states that restructured utility operations to separate the generation, transmission, distribution, and retail functions, many of the benefits of energy efficiency accrue in the form of avoided costs of generation or procuring power in wholesale markets. While these represent a societal benefit, it is not obvious how a regulated distribution company that often has the job of implementing energy efficiency should be credited for doing so. In addition, independent system operators and regional transmission organizations (ISO/RTOs) are now part of the picture,

[2] http://www.gov.state.md.us/pressreleases/070702.html
[3] http://www.westgov.org/wga/press/ee7-17-07.htm
[4] http://www.utahcleanenergy.org/EEProgram.htm
[5] http://www.pewclimate.org/node/5689
[6] http://www.energystar.gov/index.cfm?fuseaction=qhmi.showHomesMarketIndex
[7] http://www.altenergystocks.com/archives/2007/07/political_developments_in_energy_efficiency.html

creating the need for coordination, especially when it comes to designing and running demand response programs. In states that did pursue the restructuring path, these challenges do not exist.

An additional issue that arises in such states is whether the utility is the best organization to administer and implement energy efficiency programs. In some states, such as Oregon, Vermont, New York, and New Jersey, third party entities often called "efficiency utilities" have been created to administer the programs; the role of the utilities is relegated to collecting the funds to pay for these energy efficiency programs through a public goods charge that customers pay on their utility bill. Many states are considering the use of third party administrators, even those that have not restructured such as Hawaii, in order to overcome what they regard as the utility's lack of incentive to pursue energy efficiency and to eliminate any institutional conflicts of interest in pursuing a strategy that will lower revenues and possibly earnings. It is a topic of debate in state policy circles whether utilities or third party administrators are best positioned to design and execute efficient energy efficiency programs. In all cases, the entity charged with administering energy efficiency programs needs to be sufficiently funded so that it can hire staff that understands customer needs and can help meet the utility's energy efficiency objectives.

RTOs: An Emerging Force in the Demand Response Landscape

One of the biggest developments in the electric power industry over the past 12 years has been the restructuring of the industry and the rise in much of North America of the Regional Transmission Organization (RTO) as a central institution in the wholesale market place.[8] In restructured markets, RTOs constitute central markets for the purchase, sale, and scheduling of electric power on the wholesale level and currently represent 60% to 70% of peak demand in the U.S. Figure 1-2 shows a map of RTOs in North America. As wholesale institutions their concern with demand response was initially limited. Those RTOs with both day-ahead markets and real-time markets (sometimes called two settlement systems) typically allowed for sloped demand curves to be submitted in the day-ahead markets. This, in theory, would allow for load serving entities (LSEs), i.e. distribution companies, to submit bids that reflected their ability to curtail load. In fact, some markets saw significant elasticity of demand in their day-ahead markets.[9] Much of this elasticity, however, was caused by attempts to arbitrage between day-ahead and real-time prices rather than representing significant degrees of demand response.

The California power crisis of 2000/2001 helped change the picture and make RTOs realize that demand response was a vital part of restraining any market power on the part of sellers.[10] Today most RTOs have two types of programs for demand response. The first type of demand response programs are the "price responsive" or "economic" programs. In these programs, demand is reduced based on price signals in the various RTO day-ahead or real-time markets. If the bid clears, demand must be reduced in real-time. The second type of demand response programs are

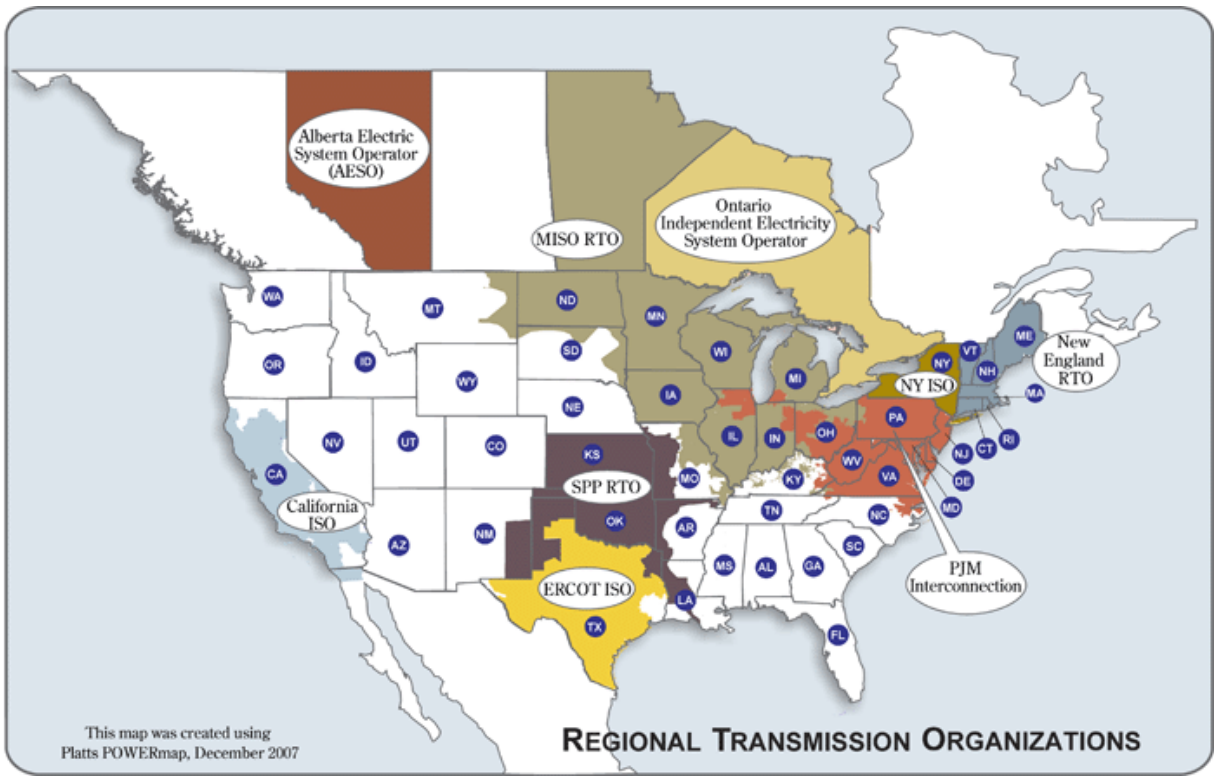
[8] While there are technical differences between ISOs and RTOs, the differences are not important for our discussion here, so we will use the term RTO for both ISOs and RTOs alike. The RTOs in the United States are CAISO (California ISO), ISO-NE (ISO New England), NYISO (New York ISO), PJM (originally Pennsylvania-Jersey-Maryland), SPP (Southwest Power Pool), MISO (Midwest ISO), and ERCOT (Electric Reliability Council of Texas).

[9] See, for example, Robert Earle, "Demand Elasticity in the California Power Exchange Day-Ahead Market", *Electricity Journal*, November 2000.

[10] See, for example, Hung-po Chao, Ahmad Faruqui, Vic Niemeyer, Jeremy Platt, and Karl Stahlkopf, "Analyzing California's Power Crisis.", *The Energy Journal*, Vol. 22, No. 4, pp. 29-52.

"emergency" programs, in which demand is reduced under emergency (or pre-emergency) conditions such as when demand eclipses reserve capacity margin. RTO protocols set limits to the manner in which demand response resources may be called during emergency conditions. Currently, emergency programs are more prevalent than economic programs for those RTOs with robust demand response programs (e.g. ISO-NE, NYISO, PJM, and ERCOT).

A key difference between the economic and emergency demand response programs is that generally economic demand response is not counted towards capacity requirements whereas emergency demand response often is. This enables emergency demand response to participate in capacity markets and thereby earn extra revenue to contribute to enabling demand response. The reason for this difference is the perception that economic demand response is less firm than emergency demand response. Once enrolled, most emergency demand response has an obligation to respond, within certain limits. By contrast, bids by economic demand response resources are voluntary, though in some cases penalties may be imposed for not following-through on pledged reductions. Generation resources, on the other hand, can generally participate in capacity markets. Importantly, however, generators are obliged to bid into markets, whereas economic demand response resources are not. RTOs are considering mechanisms whereby economic demand response resources may commit to bidding in markets, and as such become eligible for capacity market participation.



Source: FERC

Figure 1-2
Map of Regional Transmission Organizations in North America

Energy Efficiency Objectives and Programmatic Considerations

Specific energy efficiency programs and goals are likely to vary by utility and region and also over time. However, what unites them is the objective to improve the economics of the power system for the utility, the customer, and society. In areas characterized by rapid load growth, the focus may be on new construction programs. In areas with slower growth, the focus may be on retrofit programs. In areas with very sharply sloping load duration curves, such as those characterized by extreme weather conditions, one would expect to see a major emphasis on demand response programs. But there still may be a strong emphasis on energy efficiency programs if load growth is taking place at a rapid pace and/or when the marginal cost of new capacity exceeds the cost of installed capacity, which is typically the case today. In areas with relatively shallow load duration curves, such as in temperate climates, the focus will largely be on energy efficiency programs.

In states or regions with multiple program objectives such as California, where both energy efficiency and demand response programs are being emphasized, it is important to integrate and simplify the programmatic message. Ultimately, the same customers will need to be involved in both types of programs. Offering uncoordinated programs is unlikely to achieve program goals, since it will create confusion in the marketplace and customer overload.

The second generation of energy efficiency programs ended just when market transformation features involving equipment manufacturers, contractors and builders—all of whom are upstream of the end-use customer—were being brought into the picture. The third generation of energy efficiency programs is likely to bring these market transformation features into the mainstream to emphasize sustainability.

To best leverage societal resources and most rapidly meet energy savings and demand management goals, energy efficiency and demand response programs are best designed with federal and state codes and standards in mind (i.e. building and home efficiency codes; equipment and appliance efficiency standards). Codes and standards can play a significant role in complementing or amplifying energy efficiency programs. For example, California's Title 20 and 24 standards have accounted for half of the gain in energy efficiency that has occurred since 1975. The combination strategy has allowed the state to lower its electric energy consumption by 15 percent compared to what it would have been in the absence of the programs, as illustrated in Figure 1-3. [11]

Finally, utilities can facilitate the adoption of new, energy efficient technologies such as solid state lighting, advanced heat pumps, and more efficient appliances, into the market through investment in applied R&D and partnerships with equipment manufacturers through pilots and demonstrations. Examples of such technologies are discussed in Chapter 13.

[11] California Energy Commission. "California Energy Demand 2003-2013: Staff Energy Demand Forecast". Report No: CEC-100-03-002. August 2003.

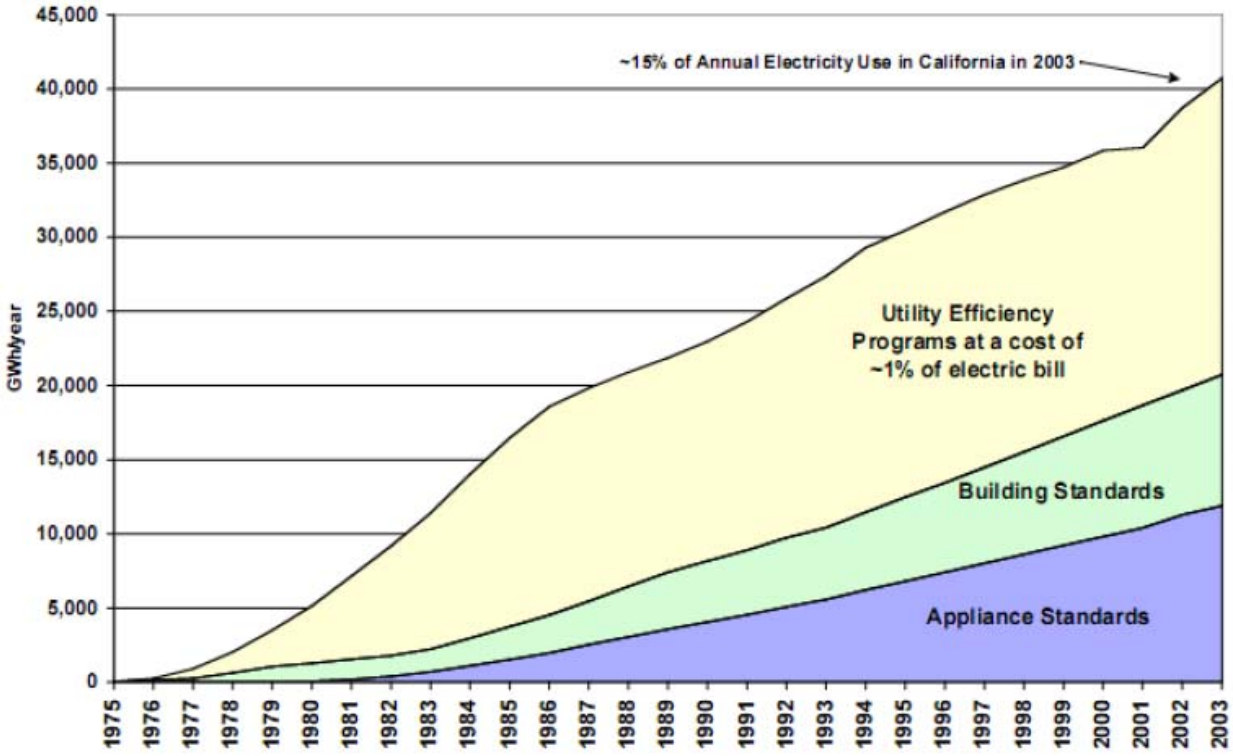


Figure 1-3
California Electricity Savings: Contribution of Programs, Codes & Standards [12]

[12] Ibid.

2
UTILITY BUSINESS MODELS FOR ENERGY EFFICIENCY

Introduction

Under traditional ratemaking, utilities have an incentive to increase electricity sales but a penalty for promoting energy efficiency (EE). The volumetric part of the electric rate generally recovers some of the fixed costs of doing business, so a decline in sales reduces fixed cost recovery and lowers earnings while a rise in sales increases it. While some states enacted regulatory policies in the 1980s and early 1990s to address these problems, these policies were largely abandoned with the move to restructured markets. These issues are being revisited in a number of states.

To overcome financial disincentives for utilities to engage in EE and to provide incentives for EE, three key issues are being addressed: program cost recovery, lost revenue recovery, and performance incentives. Financial disincentives arise from the risky or untimely recovery of program costs and the inability to cover fixed costs when or if revenues fall. Financial incentives are designed to encourage utility management to engage in EE activities. In practice, virtually all states allow cost recovery, a few allow lost revenue recovery, and several provide various forms of earnings incentives. These three key issues are summarized below:

- **Cost Recovery**. A utility's direct expenditures on EE may not be fully captured in rates. This can occur either because (a) growth in programs may increase the EE budget above the amount factored into the "test year" that was used to set rates, and rates are not adjusted frequently; or (b) utilities may be granted delayed cost recovery for EE outlays not already included in rates, but may be unable to recover the carrying charges (e.g., lost interest and borrowing costs) in the intervening period. EE program costs can be recovered on a timely basis through several mechanisms identified later in this chapter.
- **Lost Revenue.** The second EE-related financial challenge is the issue of lost revenue. A portion of the revenue from each kWh sold is intended to cover the utility's fixed costs, including its allowed cost of capital. Unless an explicit adjustment or decoupling mechanism (currently adopted by a small number of states) is put in place, each kWh "lost" as a result of EE reduces the total contribution of sales revenues to cover fixed costs and earnings.

- **Performance Incentives.** Performance incentives (also referred to as shareholder incentives or EE bonuses) can, in principle, give EE an equal footing or even an edge over other utility resource options and allow utility management to start thinking of EE as a profit center, rather than as just another cost. A performance bonus can be determined as a share of the savings produced by EE, an increment to the rate of return, as a fixed payment per kW or kWh saved, as a share of the EE costs as a proxy for accomplishment, or in other ways that link the bonus to EE program performance. More important than the calculation method is the likelihood that the utility can actually realize a monetary bonus through successful EE efforts. If the value of the bonus is uncertain, or if a comparable amount might be deducted elsewhere in a rate case, then its usefulness as a motivator is diminished. Finally, although performance incentives can benefit shareholders, such benefits may be realized at the customer's expense.

The rest of this chapter describes provides further details on regulatory mechanisms and approaches for addressing these financial issues.

Utility Corporate Objectives

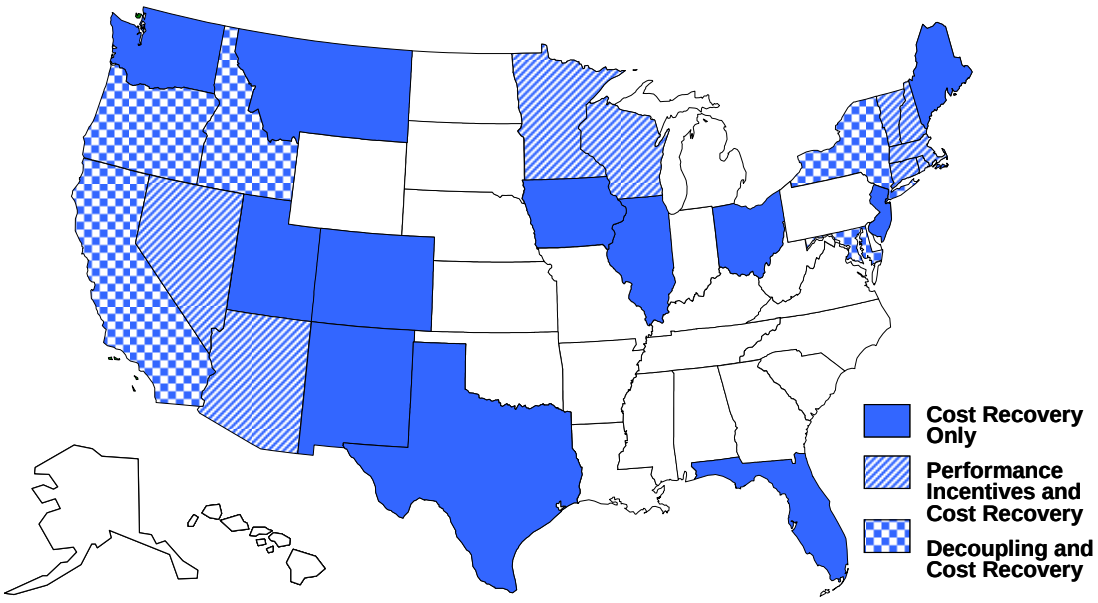
In the current business environment, some utility executives are focused on going beyond simply integrating EE into their "supply" portfolios - they want to make a sustainable business out of EE. In order to make this possible, state commissions are exploring options to remove regulatory disincentives for utility investment in EE (as they started to do in the past), as well as provide performance incentives to utilities that implement high performing EE programs.

Regulatory Setting

In practice, all of the states that have seriously implemented EE have put mechanisms in place to address the cost recovery issue, but far fewer states have mechanisms in place to address either lost revenues or performance incentives, as shown in Figure 2-1. Based on a recent report that examined 25 states with active utility-sector energy efficiency programs, the situation can be summarized as follows:[13]

- All of the 25 states examined have EE program cost recovery mechanism (outside a general rate case)
- Of these 25 states with cost recovery, 9 states also have performance incentives in place.
- Of these 25 states with cost recovery, only four—California, Idaho, New York and Maryland—have decoupled electricity sales from utility revenues (Oregon has gas decoupling only). Decoupling is currently under discussion in other states, especially in the northeast.

[13] Kushler, M., D. York, and P. Witte, "Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives". ACEEE, Report No. U061, October 2006.



- This map is limited to the 25 states covered in: Martin Kushler, Dan York and Patti White, "Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives." October 2006, ACEEE Report Number U061.
- The decoupling mechanism in Oregon is for natural gas only.

Figure 2-1
Status of Utility Regulatory Mechanisms for Energy Efficiency in 25 States

Mechanisms to Remove Disincentives for EE

This section reviews the two regulatory mechanisms that remove financial disincentives to utility EE investment—program cost recovery and lost revenue recovery—and provides examples of successful models.[14] Removal of these investment disincentives, many argue, will encourage greater utility EE activity.

A fundamental driver to advance the implementation of utility EE programs is the ability to recover the direct costs of program implementation outside a general rate case with a high degree of certainty of success. Cost recovery can be achieved through various mechanisms including: embedding costs in rates as part of resource procurement; using a special tariff rider on customer rates; recovering costs through an EE-specific cost recovery clause similar to a fuel adjustment clause; or using a systems/public benefits fund (or surcharge) on the bill to fund the programs. Based on DSIRE (Database of State Incentives for Renewables and Efficiency), 20 states currently have public benefits funds for energy efficiency.[15] Some states, such as California, use a combination of a public benefits fund and an EE rider or balancing account. Other states combine public benefits fund with rate cases.

[14] For more details on state specific models, see M Kushler, D. York, and P. Witte, "Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives." ACEEE. Report Number U061. October 2006.
[15] See http://www.Dsireusa.org.

The second fundamental driver for advancing EE programs is lost revenue recovery. The two mechanisms for recovering lost revenues are: (1) direct compensation for lost revenues from EE programs, and (2) "decoupling" of utility revenues and sales. As discussed above, only California Idaho, Maryland, and New York, have electricity decoupling. Seven states also have decoupling mechanisms in place for natural gas.

Although lost revenue recovery is a major concern to some utilities, many states have chosen to address this issue only indirectly by offering performance incentives.

Mechanisms to Provide Incentives for EE

In addition to the nine states shown in Figure 2-1 that have performance incentives in place—Arizona, Connecticut, Massachusetts, Minnesota, Nevada, New Hampshire, Rhode Island, Vermont, and Wisconsin—California has also adopted a policy of shareholder incentives in its Energy Action Plan. The California Public Utility Commission recently set the shareholder incentive amount at 12%.

Shareholder or performance incentives can be provided in different ways including the following:

- **Shared Savings**. Utility receives an incentive equal to some percentage of the program's net savings[16] for achieving some targeted range of savings agreed upon between the regulator and the utility. California used shared savings from 1991 to 1997 and is proposing to use it again.
- **Performance Rewards**. Utility receives a specified financial reward for meeting or exceeding performance goals or targets measured either in GWh and MW, or EE spending For example, Massachusetts offers an incentive of 8.25% of program costs at 100% of target.
- **ROE Kicker.** Utility earns a return on equity (ROE) on its EE costs that is greater than the ROE on its supply-side investments, which equals their cost of capital. For example, Nevada has an ROE kicker and Florida has accelerated depreciation on selected EE costs.
- **Virtual Power Plant incentive**. Utility gets a percentage of the avoided supply-side but takes on the obligation to pay for EE programs to absorb the risk of program performance and the recovery of lost fixed costs in between general rate cases. For example, Duke Energy filed for its *Save-A-Watt* EE program in North Carolina in May 2007, which is pending regulatory decision.

[16] Net savings equal gross benefits minus costs

Examples of Performance Incentives in Action

ROE Kicker

In Nevada, an enhanced return on equity applies to investments in EE. Currently, the ROE "kicker" is equal to 5% and is applied to EE expenditures. Hence, the utility receives a higher return on EE investments than on its other capital investments.

Shared Savings

CA Shared Savings. The California model combines expensing of EE costs with a balancing account[17], lost revenue recovery through decoupling, and, if approved, a shareholder incentive.

*Financial incentives = ([12% * net program benefits (or savings)] + lost base revenues + immediate cost recovery).*

Net program benefits are defined as total benefits resulting from EE less program costs. This model results in the customer receiving 88% of the net program savings. In addition to program benefits, shareholder benefits also include through recovery of lost base revenues (through decoupling) and cost recovery.

Duke "Save-A-Watt". Under the Duke model, the utility absorbs total program costs and is exposed to risk for lost base revenues, but then recovers, over time, a set percentage of the avoided cost benefits, calculated based on EE estimates. These estimates must be validated through state of the art measurement and verification studies.

*Shareholder incentive = ([90% * <u>total</u> avoided cost savings] - program costs - lost base revenues).*

This model is based on total program savings and results in the customer receiving 10% of total program savings.

Performance Rewards

Several states have performance incentives that reward utilities for meeting or exceeding EE program targets or goals. [18] In Arizona, for example, utilities receive a performance incentive based on net benefits from EE subject to a cap of 10% of EE total spending. In Minnesota, for every percentage point above 90% of the established EE goal, utilities receive a percentage of total net benefits resulting from EE, subject to a cap of 30%. The specific details of EE performance rewards vary by state.

[17] This is done by adjusting electric rates each year to balance out revenue gains or losses.
[18] See C. Harrington, C. Murray, and L. Baldwin, "Energy Efficiency Policy Toolkit." The Regulatory Assistance Project. January 2007.

EE as a Business: Summary

Regardless of utility structure—investor-owned, municipal, or cooperative—some method of cost recovery (including direct program costs and indirect fixed costs associated with operations) is essential for sustained investments in EE. To this end, some states have enacted performance incentive mechanisms or decoupled electricity sales from revenues, with the former more prevalent than the latter.

Performance incentive mechanisms come in different flavors and vary in complexity, but are essentially performance "bonuses" that encourage EE over other utility resource options. The fact that several states provide them suggests that such incentives are politically and economically viable. Importantly, these incentives allow utility management to treat EE as a business or profit center, rather than as just another cost. Once the issue of cost recovery is resolved, performance incentives are a lever that can elevate EE as a strategic utility business opportunity.

3
THE ENERGY EFFICIENCY PROCESS

Introduction

The development of effective energy efficiency (EE) programs and services to yield anticipated energy and demand impacts essentially entails the following nine sequential steps:

Establishing objectives

Baseline forecasting

Screening of measures (technical and economic criteria)

Sizing up customer acceptance and response

Estimating savings potentials (technical, economic, and achievable)

Program design and impact estimation

Measuring cost-effectiveness of programs

Implementation and monitoring of programs

Evaluation, measurement, and verification of program impacts

This chapter provides a brief overview of this nine-step process, as illustrated in Figure 3-1. Chapters 4 through 12 of this guidebook provide a detailed discussion of each step.

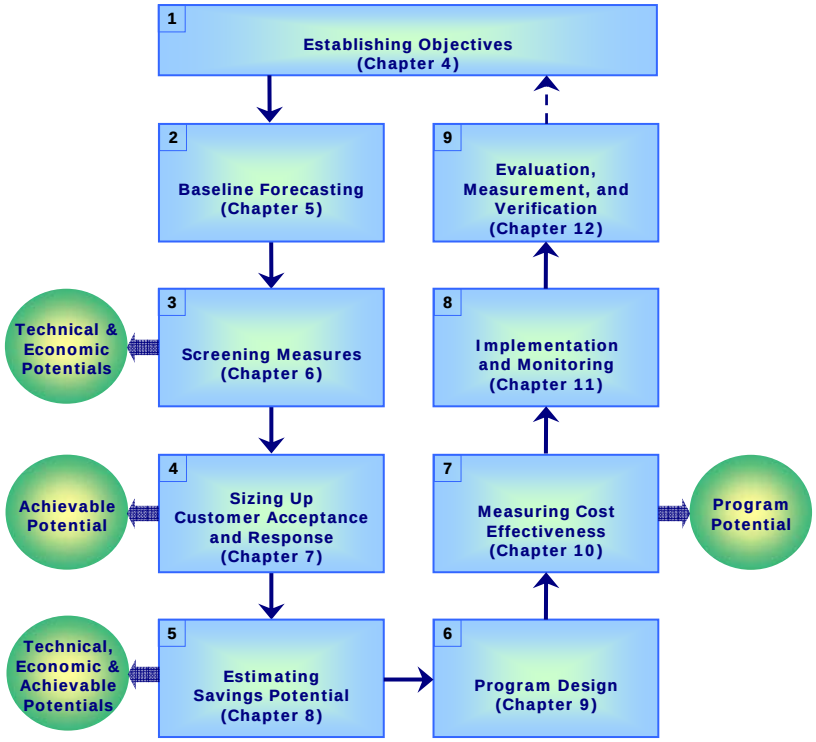


Figure 3-1
EE Program Process

EE Objectives

The first step in the process is to establish objectives. In today's business environment, utilities are focused on both demand- and supply-side resources to meet the needs of customers, shareholders, and regulators. However, due to the significant reorganization of the electric utility industry over the past two decades, utilities may differ in their EE objectives depending on whether they are in restructured or un-restructured states.

Investor-owned utilities (IOUs), particularly in the south and much of the west, are still regulated and vertically integrated (i.e., responsible for generation, transmission, and distribution of electricity). In these instances, reducing or shifting demand will avoid new supply costs. In contrast, IOUs in the northeast and parts of the Midwest have unbundled (or separated) their generation, transmission, and distribution functions. As a result, the distribution company is subject to continued regulation and is the entity most likely to administer EE programs. Such distribution companies, also called load serving entities or LSEs, purchase power from generators, typically as a pass-through cost for their consumers. Hence, reducing or shifting demand via EE will not defer new supply costs for a stand-alone distribution company, per se. However, the overall cost to serve customers on EE programs, particularly load shifting

programs, will decline. From a societal resource cost perspective, EE can provide clear benefits.[19]

Based on individual utility goals, state mandates, and federal mandates, the typical EE objectives are to:

- Conserve energy
- Reduce peak demand
- Increase system reliability
- Reduce carbon and other emissions
- Avoid or defer building new power plants
- Avoid or defer building new T&D infrastructure

Chapter 4 of this guidebook provides a more detailed discussion of establishing EE objectives. In today's environment, EE is viewed as a resource to meet energy needs. In some states, such as California, EE is on an equal footing with supply side resources and EE resources must be exhausted before new power plants are approved. In today's environment, EE is increasingly becoming part of a utility's portfolio of resources.

EE measures and programs that are designed to meet these objectives can usefully be divided into two categories:

- Energy efficiency/conservation
- Demand response (DR)

Throughout this guidebook, in particular when we discuss measuring cost effectiveness, estimating program impacts, program implementation, and program evaluation, we will distinguish between energy efficiency/conservation and DR measures and programs.

Baseline Forecasting

The baseline forecast represents a projection of energy consumption and peak demand in the absence of EE. The baseline serves as a reference against which the impact of EE can be assessed. The EE baseline forecast is based on a utility's load forecast but it is typically much more detailed.

- The residential sector baseline forecast typically projects annual electric consumption and seasonal coincident peak demand for major end uses of electricity including heating, ventilation, and air conditioning (HVAC), appliances, and lighting. Typically a forecast is prepared by three dwelling types: single family, multi-family, and modular homes.

[19] The issue of valuing the benefits of EE based on resource costs versus contracted prices has been debated in California, for example, where the state contracted for power under long-term contracts during the energy crisis. In California, the state has decided that the appropriate way to measure the benefits of demand-side resources is to use estimates of resource costs.

- The commercial sector baseline forecast projects annual electric consumption and seasonal coincident peak demand for major appliance end uses (i.e., water heating, cooking, refrigeration, and lighting) and HVAC. Commercial projections are typically prepared by building type (e.g., office, retail, grocery, restaurant, warehouse, school, college, hospital, etc.).
- The industrial sector baseline forecast projects annual electric consumption and seasonal coincident peak demand for major end uses such as motors, process heating, refrigeration, lighting, HVAC, and other. Industrial projections are typically prepared for each major industrial segment (e.g., primary metals, machinery manufacturing, etc.) applicable to the utility service territory.

Chapter 5 of this guidebook provides a detailed explanation of baseline forecasting.

Screening EE Measures

Most utilities are aware of the wide range of potential EE measures, which include technologies aimed at conservation/efficiency and load management, as well as innovative rate options such as dynamic rates, interruptible rates, and curtailable rates. The Energy Information Agency (EIA) publishes an annual update to a comprehensive database of EE programs for the electric utility industry, which tracks annual and program-to-date (PTD) demand (MW) impacts, energy savings impacts (MWh), peak load reduction, program expenditures, and other data.[20] .

Once the range of measures is identified, preliminary screening is a three step process. The first step is to screen out EE measures that are not appropriate to the housing and building stock in the utility service area. After this qualitative screening, the second step is to estimate the energy savings and peak demand impacts of the EE measures. This can be done using engineering calculations for non weather-sensitive end uses (such as a compact fluorescent bulb). For weather-sensitive end uses such as heating and cooling, engineering simulation models using prototype dwellings or buildings are typically used to estimate the energy savings and peak demand impacts of the measures. For innovative rate options, statistical/econometric models that include estimates of demand elasticities are used to estimate energy savings and load impacts. The final step is to estimate the costs of the measures. Cost data can typically be gathered from secondary sources, vendors, and distributors.

Chapter 6 of this guidebook provides a detailed discussion of screening EE measures.

Program Design

Effective EE program design is based on a solid understanding of customer preferences and customer response as well as the likely program energy and demand impacts. For each program concept, in addition to understanding both the program costs and delivery mechanisms, three customer-dependent measures will determine whether or not an EE program is cost-effective:

- Program participation rates and customer response

[20] The EIA database contains information on energy efficiency programs and load management programs. See U.S. Energy Information Agency at http://www.eia.doe.gov/cneaf/electricity/page/eia861.html

- Market penetration (for EE programs that involve multiple units)
- Program energy and demand impacts

Program design is a multi-step process that starts with identifying and understanding target markets. The next step is to design programs with features that meet customer needs. The final step is to market and deliver the program. The success of the program design, marketing, and delivery process will ultimately determine program participation rates and the overall energy and demand impacts. Chapters 7, 8, and 9 provide a detailed discussion of program participation and customer response, estimating energy and demand impacts, and EE program design.

Cost-Benefit Analysis

Five economic tests are widely used to assess the cost-effectiveness of EE programs. These tests are often referred to as the "standard practice" tests in the industry because they are based on the California Standard Practice Manual.[21]

The five different tests were developed to address the issue that EE program have different impacts on different groups of customers and the utility.

- The **participant test** addresses the participant's perspective: "Are participants better off as a result of the program?"
- The **total resource cost (TRC) test** addresses the perspective of the utilities and the ratepayers: "Does the total resource cost go down?"
- The **ratepayer impact (RIM) test** addresses the utility's rates perspective, "Will rates increase as a result of the program?"
- The **utility cost test** addresses the utility's total cost perspective: "Are revenue requirements lower as a result of the program?"
- The **societal test** addresses society as a whole, "Will societal costs go down as a result of the program?"

Although these tests were originally developed in the 1980s, they remain essentially unchanged over the years and are in wide use today. Two additional factors, however, warrant discussion: (1) environmental benefits should be explicitly included in both the societal test and the total resource cost test; and (2) the issue of consumer surplus, which represents the difference between the "value" that customers derive from consuming a product and the amount they actually pay for it.[22] Chapter 10 provides a detailed discussion of measuring cost-effectiveness using these standard cost-benefit tests, and addresses the inclusion of environmental benefits and the issue of consumer surplus.

[21] California Standard Practice Manual: Economic Analysis of Demand Side Programs and Projects, July 2002. http://drrc.lbl.gov/pubs/CA-SPManual-7-02.pdf

[22] Another way to think about this is that a consumer's willingness to pay for a product or service will always be greater than or equal to its price.

Implementation and Monitoring

Once a program has been designed, and program participation, energy and demand impacts, and costs have been estimated, it is ready for execution. The implementation and monitoring step in the EE process is where the "rubber meets the road." Depending on the characteristics of the EE program and the experience of its staff, a utility may opt for a pilot program or full scale implementation.

A pilot program may be the appropriate first step: (a) for particularly innovative EE programs, such as the dynamic pricing options which several utilities are piloting today; (b) when utility staff has limited experience with EE programs; or (c) when the cost of rolling out the program is very high. Pilot programs offer an opportunity to test a program, find out what works, and then fine tune the design as well as the estimates of impacts and costs. On the other hand, if the utility has experienced staff and the program is not particularly innovative or costly, it may be appropriate to proceed to full scale program implementation.

The success of an EE program depends on effective marketing and management. Once program delivery begins, the marketing plan must be executed and the implementation staff must be successfully managed. Implementing EE programs may also require the cooperation of trade allies, contractors, and others outside of the utility.

Finally, ongoing program monitoring is essential to quantifying accomplishments (i.e., customer participation, energy, and load impacts); tracking costs, monitoring contractor performance, keeping programs on track, and (if required for performance incentives or otherwise) regulatory reporting.

Chapter 11 provides a detailed discussion of program implementation and monitoring.

Evaluation, Measurement, and Verification

Program evaluation is the *ex post* assessment of the effectiveness of the EE program. Typically EE program evaluations fall into two categories: process evaluations and impact evaluations.

- Process evaluations address program delivery, promotional strategies, coordination, customer satisfaction, and market acceptance. Process evaluations are typically qualitative in nature and rely on surveys, interviews, site visits, and document review.
- Impact evaluations quantify the effects of a program in terms of program participation rates, energy impacts, and load impacts. Impact evaluations are quantitative in nature and rely on metering data, engineering calculations, and statistical modeling.

The purpose of a process evaluation is to assess the overall performance of the program and to recommend changes to improve program effectiveness. In contrast, the purpose of an impact evaluation is to quantify the effects of a program in terms of energy and demand impacts. Chapter 12 provides a detailed discussion of EE evaluation, measurement, and verification.

4
ESTABLISHING ENERGY EFFICIENCY OBJECTIVES

Background

The first step of the EE program process is to clarify and establish the utility's strategic objectives.

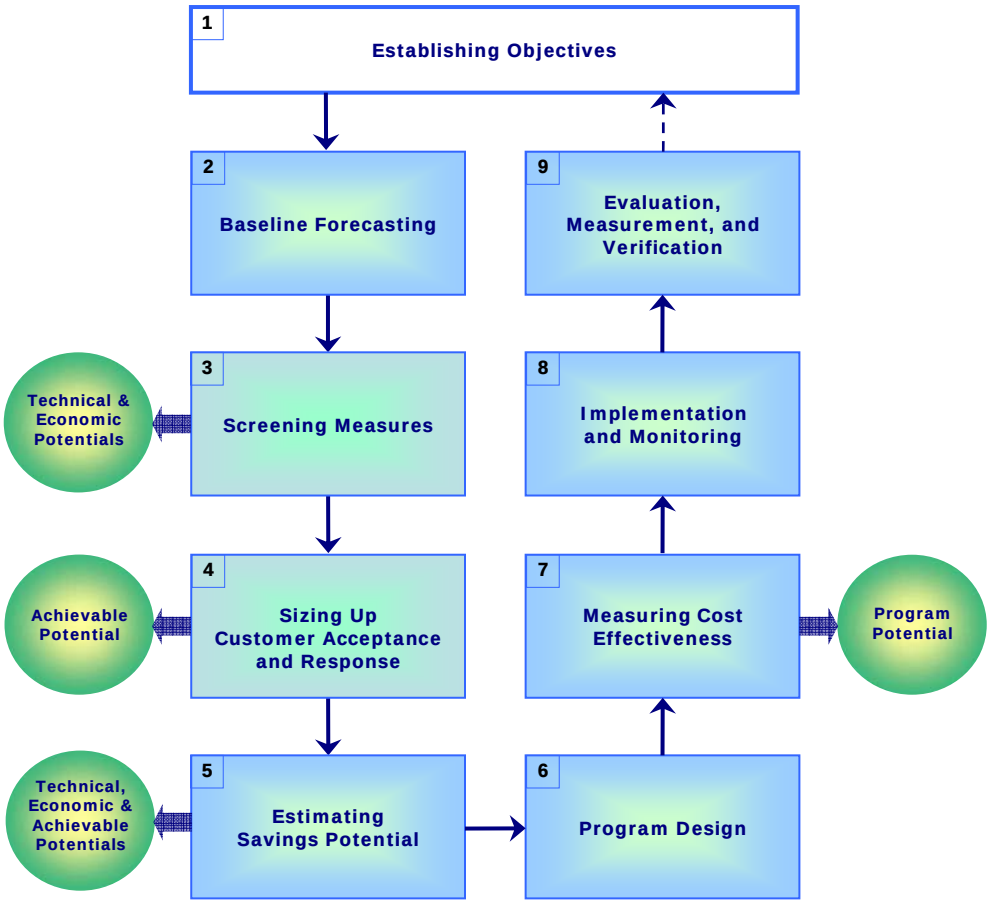


Figure 4-1
EE Program Process, Step 1: Establishing Objectives

In today's business environment, a growing number of utilities are focused on both demand- and supply-side resources to meet energy needs. The renewed interest in demand side resources is a result of increasing pressure from the public, state regulators, and federal policy makers to meet growing energy demand in a cost-effective and environmentally sustainable manner. At the same time, utilities have an obligation to serve the best interests of their shareholders. Although the third generation of EE programs alluded to in Chapter 1 bears some resemblance to the demand side management (DSM) programs that prevailed in the late 1980s and early 1990s, the policy context for EE now includes the following three considerations: [23]

- An emphasis on aligning financial incentives for shareholders with customers
- Focus on EE as a resource
- Concern about carbon emissions

The over arching objectives of EE are closely tied to this new policy context.

First, as a result of the significant restructuring of the U.S. electric utility industry over the past decade, utilities today face different circumstances with regard to implementing EE and financial incentives must be aligned accordingly.

- For investor owned utilities (IOUs), particularly in the south and west, that are still regulated and vertically integrated (i.e., responsible for generation, transmission, and distribution of energy), reducing energy or lowering peak demand as a result of EE will avoid new supply costs. However, under conventional regulation, EE investments are not as rewarding as supply side investments. As discussed in Chapter 2, lost sales from energy efficiency will have a negative effect on financial performance unless cost-recovery strategies are in place.
- For IOUs, particularly in the northeast and parts of the Midwest, that have unbundled their generation, transmission, and distribution functions, the distribution company (or load serving entity, LSE) is subject to continued regulation and is the entity that typically administers EE programs.[24] Such distribution companies purchase power for their customers and the cost of that energy is typically a pass-through.[25] For these stand-alone distribution companies, reducing or shifting demand via EE will not defer new supply costs. From a societal resource cost perspective, EE can provide a clear benefit in deferring or avoiding investment in generation, transmission, or distribution infrastructure.[26] However, foregone electricity sales due to EE may have an even greater negative effect on the financial performance of stand-alone distribution companies than for vertically integrated utilities, so cost recovery strategies are even more critical.[27]

[23] V. Jensen, "Aligning Utility Incentives with Investment in Energy Efficiency: A product of the National Action Plan for Energy Efficiency." ICF International. July 2007.
[24] In some states, a state agency administers EE programs.
[25] At this point in time, most of all of the distribution companies in the U.S. are load serving entities meaning that they are responsible for supplying power to their customers.
[26] The issue of valuing the benefits of EE based on resource costs versus contracts has been debated in California. In California, the state has decided that the appropriate way to measure the benefits of demand-side resources is to use estimates of resource costs.
[27] See C. Harrington, C. Murray, and L. Baldwin, "Energy Efficiency Policy Toolkit," Regulatory Assistance Project. January 2007. Page 21. www.raponline.org

Second, as a result of projections that demand for energy will exceed supply in some areas of the country (i.e., projected capacity shortages) coupled with the costs, risks, and siting issues surrounding new generation, there is a renewed focus on resource planning. Increasingly EE is regarded as a key resource on the same footing as supply side resources in such planning and as a means to maintain or increase reliability. California, for example, adopted an Energy Action Plan in 2003 that defines a "loading order" of energy resources that places energy efficiency as the first priority, followed in order by renewables, distributed generation, and finally clean fossil-fueled generation.[28]

Finally, utility companies, state policy makers, and federal policy makers all recognize the need to mitigate climate change as well as the potential costs to the utility industry that may result from climate change legislation. EE is regarded as a key resource to help utilities reduce carbon emissions.

Corporate Objectives, Policy Interests, and EE

As a result of the renewed policy interest in EE, utility investments in energy efficiency programs, both actual and planned, are increasing significantly. As these investments increase, electric utilities are increasingly concerned about how the costs of utility-sponsored EE programs are recovered.[29] Hence, a major objective of electric utilities is to align their financial interests with policy interests that support increased investment in EE. As discussed in Chapter 2, both EE program cost recovery and lost revenue recovery are two regulatory mechanisms that remove the financial disincentive to invest in EE. Performance incentives are a third regulatory mechanism; they provide a financial incentive via shared savings, performance rewards, or an increased ROE for utilities to invest in EE.

The National Action Plan for Energy Efficiency (NAPEE) identifies key barriers limiting greater U.S. investment in energy efficiency, and documents sound business practices for removing these barriers.[30] The goal of NAPEE is to create a sustainable, aggressive national commitment to energy efficiency.[31] The NAPEE report states that "Energy efficiency is a critically underutilized resource in the nation's energy portfolio," and notes that utilities are in a unique position to lead in energy efficiency. [32]

As a result of these different interests and perspectives, multiple EE objectives emerge.

- From the utility perspective, a major objective is to align their financial interests with investments in EE. This requires a combination of cost recovery and incentive mechanisms to enhance utility investment in EE, as elaborated upon in Chapter 2.

[28] California Energy Action Plan. California Public Utilities Commission (CPUC) rulemaking (R.02-11-039). Adopted April 30, 2003 by the California Energy Commission. Adopted May 8, 2003 by the CPUC.
[29] These issues were also discussed in the late 1980s/early 90s and some states enacted policies to address them. However, with the advent of restructuring, most of these policies were abandoned.
[30] See www.epa.gov/cleanenergy/eeactionplan.htm
[31] NAPEE defines energy efficiency very broadly as using less energy at any time including through demand response and peak shaving efforts. Demand response and peak shaving efforts are more typically referred to as demand response, demand management, or load management. In this report, we define EE in the same way and use the term DSM only to refer to the historical period when the term was used.
[32] See www.epa.gov/cleanenergy/eeactionplan.htm

- Assuming financial incentives are in place, a second major objective is to utilize EE as a resource wherever cost-effective, thereby delaying the need for new power plants.[33] In a growing number of states, EE has been placed on an equal footing with supply side resources and is viewed as a resource to meet energy needs.[34]
- A third major objective is to utilize EE programs as a means to reduce carbon emissions. While reducing energy consumption will reduce carbon emissions, shifting energy usage through some forms of demand response may not reduce carbon emissions.[35]

Competing and Complementary EE Objectives

Throughout this guidebook, we divide EE into its two broad categories: energy efficiency and demand response (DR). In the late 1980s and early 1990s, DSM program objectives were viewed as "load shaping objectives" such as peak shaving, load shifting, valley filling, strategic load growth, and conservation. However, in today's environment, as the landscape has shifted, the engineering-centric objectives of EE have expanded to include its role in improving reliability, reducing the need for new supply side resources, and improving the utility's carbon footprint.

- The primary goal of energy efficiency measures and programs is to reduce the consumption of energy without compromising value to the end user. Examples of energy efficiency programs include appliance efficiency programs, HVAC efficiency programs, and building envelope programs. In addition to saving energy, these programs can offset the need for new supply options and will typically result in reduced carbon emissions.
- The primary goal of demand response (DR) measures and programs is to reduce peak demand. DR programs may also increase reliability. Examples of DR programs are critical peak pricing (CPP), real time pricing (RTP), interruptible and curtailable rates, and load control. DR programs that result in load shifting may or may not result in energy savings and are unlikely to result in reduced carbon emissions.[36]

Summary

A necessary condition for increased investment in EE is aligning the utility's financial incentives. Once this is in place, EE programs have an important role beyond saving energy and reducing peak demand. EE programs can lead to improved reliability, a reduced need for new supply options, and an improved carbon footprint.

[33] The issue of cost effectiveness and the standard benefit cost tests are discussed in detail in Chapter 7. Most states currently use the Total Resource Cost (TRC) test to determine whether a particular EE program is cost effective. However, a few states still use the Rate Impact (RIM) test. For a description of these tests see, California Standard Practice Manual: Economic Analysis of Demand Side Programs and Projects. July 2002.

[34] In California, for example, EE must be exhausted before new power plants are considered or approved. However, in some states, EE is not yet on an equal footing with supply side resources.

[35] EPRI is currently pursuing research to model the marginal carbon emissions impact of energy efficiency. In this approach, emissions impact is a function of both the generation mix and load shape of end use measures. To the extent that load shifting programs merely shift generation from on-peak to off-peak periods with no conservation effect, the relative carbon-intensities of these periods will determine how much, if any, carbon emissions is avoided.

[36] DR programs that entail peak load reduction without shifting will likely reduce carbon emissions. However, as explained in the previous footnote, load shifting DR measures may not result in reduced carbon emissions. This determination is utility-specific and dependent on the generation fuel mix and load shape characteristics of end use efficiency measures.

5
BASELINE FORECASTING

Introduction

Defining a baseline forecast is the second step of the EE program process, as illustrated in Figure 5-1. The objective of this step is to establish a forecast of electric energy consumption and peak demand in the absence of new EE programs.[37]

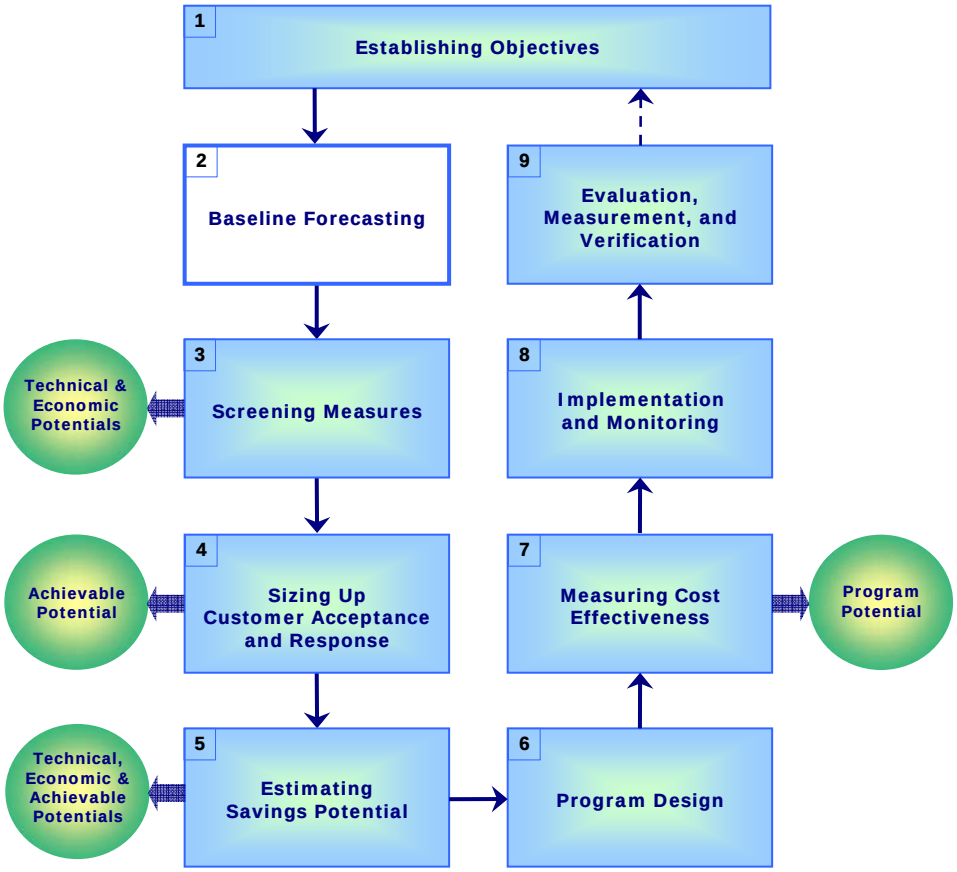


Figure 5-1
EE Program Process, Step 2: Baseline Forecasting

[37] In the context of this document, "EE" refers to both energy efficiency/conservation and demand response.

This baseline forecast establishes a reference against which the impact of EE measures can be assessed. Most frequently the forecast is represented by single yearly values for a specific set of variables, such as annual energy consumption, summer peak demand, and winter peak demand, for each year of the analysis. Some utilities use a range around the point forecast using either probabilistic or scenario generation methods. In addition, for demand response programs and demand trading operations, tools for short-range hourly load forecasts have become important to utilities to determine the timing and magnitudes of peak demands.

This chapter describes the different approaches to developing a baseline forecast and discusses the characteristics of residential, commercial, and industrial sector baseline forecasts.

The EE Program Baseline Forecast

The EE program baseline forecast should be derived from the utility's official load forecast that is used to project utility capacity needs and fuel costs as well as to evaluate supply-side options against which EE options will compete. Usually, the official load forecast does not contain the level of detail necessary to assess the impact on the forecasted energy consumption and peak demand of specific EE measures. As a result, for the EE program baseline forecast, a more detailed breakdown of this load forecast information, and the assumptions behind it, is often required. Even if the official load forecast contains the necessary level of detail, the computational methods used to develop it typically do not permit the assessment of the impacts of EE measures. Therefore, it is usually necessary to create a separate computational framework that generates a detailed EE program baseline forecast.

The level of detail used in developing the EE program baseline forecast is a function of data availability. Figure 5-2 illustrates the different levels of detail that can be included in the baseline forecast, starting with information at the system level and becoming progressively more detailed at levels corresponding to information at the sector, segment, end-use, technology, and equipment levels, respectively. Typically, a distinction is made between different vintages, such as existing and new construction. Sometimes an additional distinction is made for owner-occupied versus tenant-occupied buildings.

Most utilities' official load forecasts are developed with econometric models that result in projections at the sector or segment level. A few utilities use a combination of econometric and end-use models that result in projections at the end-use level. Other methods such as time series analysis or informed opinion may also be employed alone or in conjunction with other techniques in utility load forecasting.

Ideally, to assess the impact of all applicable EE measures thoroughly, the EE program baseline forecast should be established at the most detailed level, i.e., at the equipment level. However, the data required to accomplish this goal are typically not available or are available only for very few end-uses and technologies. Therefore, in most cases, it is not possible to establish the EE program baseline forecast at the equipment level.

The baseline forecast should take into account naturally-occurring efficiency improvements, effects of appliance standards and building codes, and impacts of existing EE programs. These

variables are usually included in a utility's official load forecast. However, the baseline forecast should not include any impacts of future EE programs, since the purpose of the baseline forecast is to serve as a reference for quantifying impacts of future EE program efforts. Because utility forecasts may assume some degree of impact from future EE programs, the effects of future programs must be removed from the utility's official load forecast in order to have a proper baseline forecast from which to compare future EE programs.

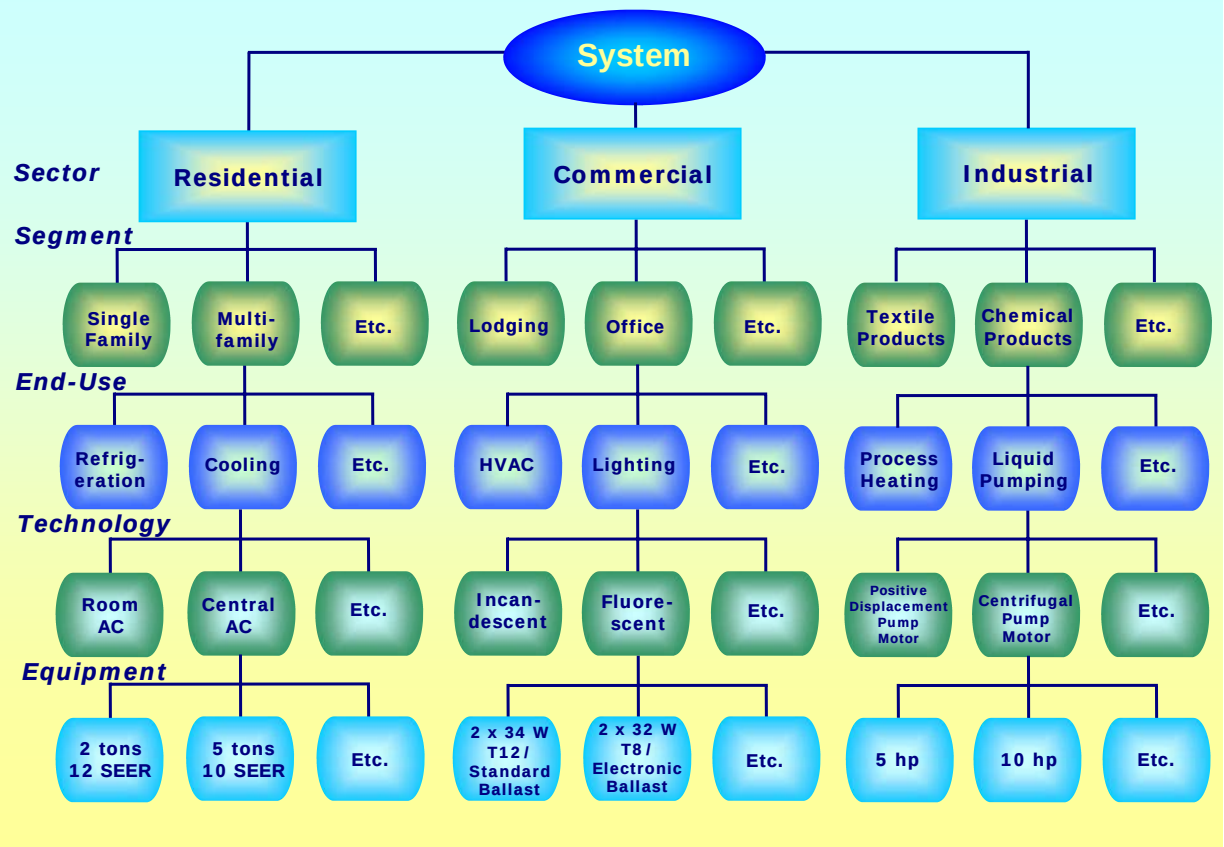


Figure 5-2
Levels of Detail in an EE Program Baseline Forecast

Approaches to Developing an EE Program Baseline Forecast

It is useful to establish baseline forecasts for the major sectors in a utility's service territory, such as the residential, commercial and industrial sectors. The best approach to developing a baseline forecast is a function of data and resource availability. The following subsections describe four of the main methods used in baseline forecast development:

- Bottom-up approach
- Top-down approach
- Hybrid bottom-up/top-down approach
- Prototype approach—a variation of the bottom-up approach

While a bottom-up approach is preferred because it is more rigorous in nature, top-down or hybrid approaches are most commonly employed since they have fewer data and resource requirements. The decision to use a top-down or hybrid approach instead of a bottom-up approach is a function of time/budget tradeoffs and whether the utility requires the detailed results of a bottom-up study or if the order-of-magnitude results characteristic of top-down or hybrid studies are sufficient. Utilities more often decide that top-down or hybrid approaches will provide enough information to move forward with their planning activities.

Bottom-Up Approach

In an ideal situation, if estimates of saturation rates, annual energy consumption, demand at the time of the system peak, and other parameters required for EE program assessment are available for all applicable equipment and end-uses and for all the analysis years, the baseline forecast can be developed in a building block, bottom-up fashion, illustrated in Figure 5-3.

The *bottom-up approach* begins with: (a) a detailed equipment inventory (e.g., number of 20-cubic-foot refrigerators, number of 2 x 32-Watt T8 / electronic ballast fluorescent light fixtures); (b) corresponding average annual energy consumption per device, known as "Unit Energy Consumption" or UEC; and (c) diversified load at the time of the system peak, known as "Unit Coincident Demand" or UCD for each type of equipment and for each year of the analysis.

In each market segment (e.g., existing single-family housing, new office buildings, etc.) the annual energy and peak demand are calculated as the product of the number of devices times the corresponding UEC and UCD. For example, to calculate the 2007 energy contribution of 20-cubic-foot refrigerators in existing single-family housing, the number of such refrigerators is first calculated by multiplying the total number of existing single-family units in 2007 by the saturation of 20-cubic-foot refrigerators in that market segment. This value is then multiplied by the 2007 average annual energy use per existing 20-cubic-foot refrigerator.

This process is repeated for the other types and vintages of equipment and market segments, and the results are aggregated across all equipment types and vintages, end-uses, and sectors to arrive at the subtotal of annual energy or peak demand consumption in the sector. The results are compared and calibrated to the utility's official load forecast at the level that this forecast is available—usually at the segment or sector level.

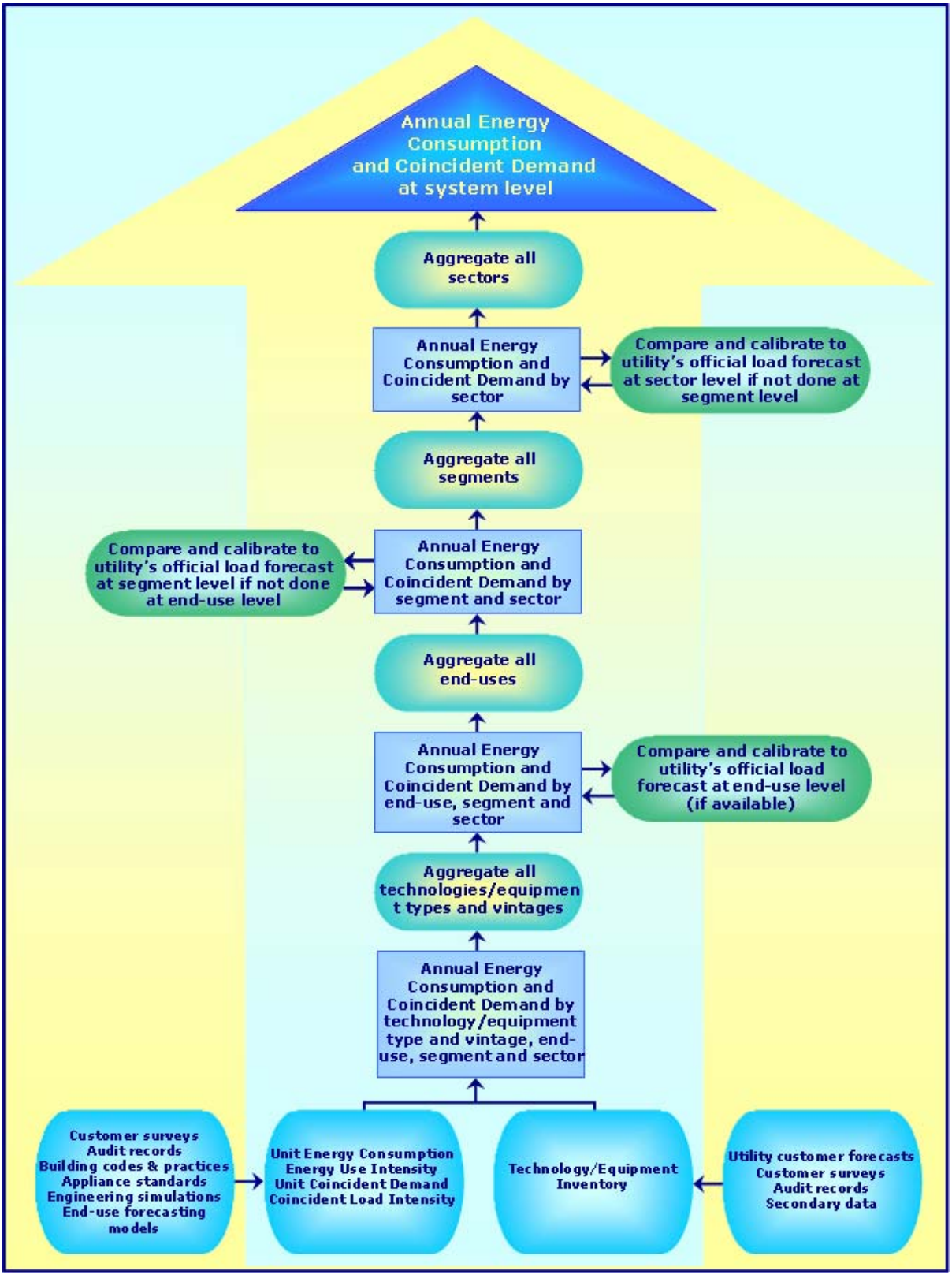


Figure 5-3
Establishing an EE Program Baseline Forecast: Bottom-Up Approach

The data required to develop a baseline forecast employing a true bottom-up approach, starting at the equipment level, are so detailed that they are typically not available or are available only for very few devices, end-uses, and segments. Alternatively, the bottom-up approach can be started at the technology level (e.g., refrigerators, fluorescent light fixtures) where more data might be available. At this level, for the residential sector, the analysis starts with a technology inventory and the corresponding average UEC and UCD. For the commercial and industrial sectors, it starts with applicable square footage and average annual energy consumption per square foot, known as "Energy Use Intensity" or EUI, and the load at the time of the system peak, known as "Coincident Load Intensity" or CLI.

The value of one or more of the parameters discussed above is typically not available for every year of the analysis. For instance, saturation forecasts by type of technology may not be available for future years. In this case, the saturation values can be kept constant at the base-year value or secondary data that permit the development of trend forecasts can be used.

Many utilities forecast load shapes at the sector, segment, and/or end-use levels. This is often accomplished through analysis of day types (e.g., average June weekday, January peak day, etc.). Such analysis requires substantially more data and effort than analysis of just energy and peak demand, but the additional detail provided can greatly assist in integrated resource planning (IRP) and EE program planning.

Even starting at the technology level, the bottom-up approach requires very detailed data that are available with any degree of confidence only for the residential customer class in some cases, as well as for a few technologies, end-uses, and segments in the commercial sector. Therefore, the bottom-up approach can sometimes be used to develop a residential sector base case, but other types of approaches are more likely to be used for the commercial and industrial classes.

Top-Down Approach

Figure 5-4 illustrates an approach that can be used to develop an EE program baseline forecast when the bottom-up approach cannot be used due to lack of primary data at the technology or end-use level.[38] This is often true for the commercial and industrial sectors. In the *top-down approach*, the baseline forecast is developed from information at the customer sector or segment level. The starting point for this approach is the utility's official load forecast, which is allocated down to the different hierarchical levels. Since the official load forecast is so intrinsic to this approach, it is important to make sure that any projected impacts of future EE programs are removed from the official load forecast.

[38] Primary data refers to data specific to the utility's territory. Secondary data refers to data developed by other utilities or organizations that are not specific to the utility's territory.

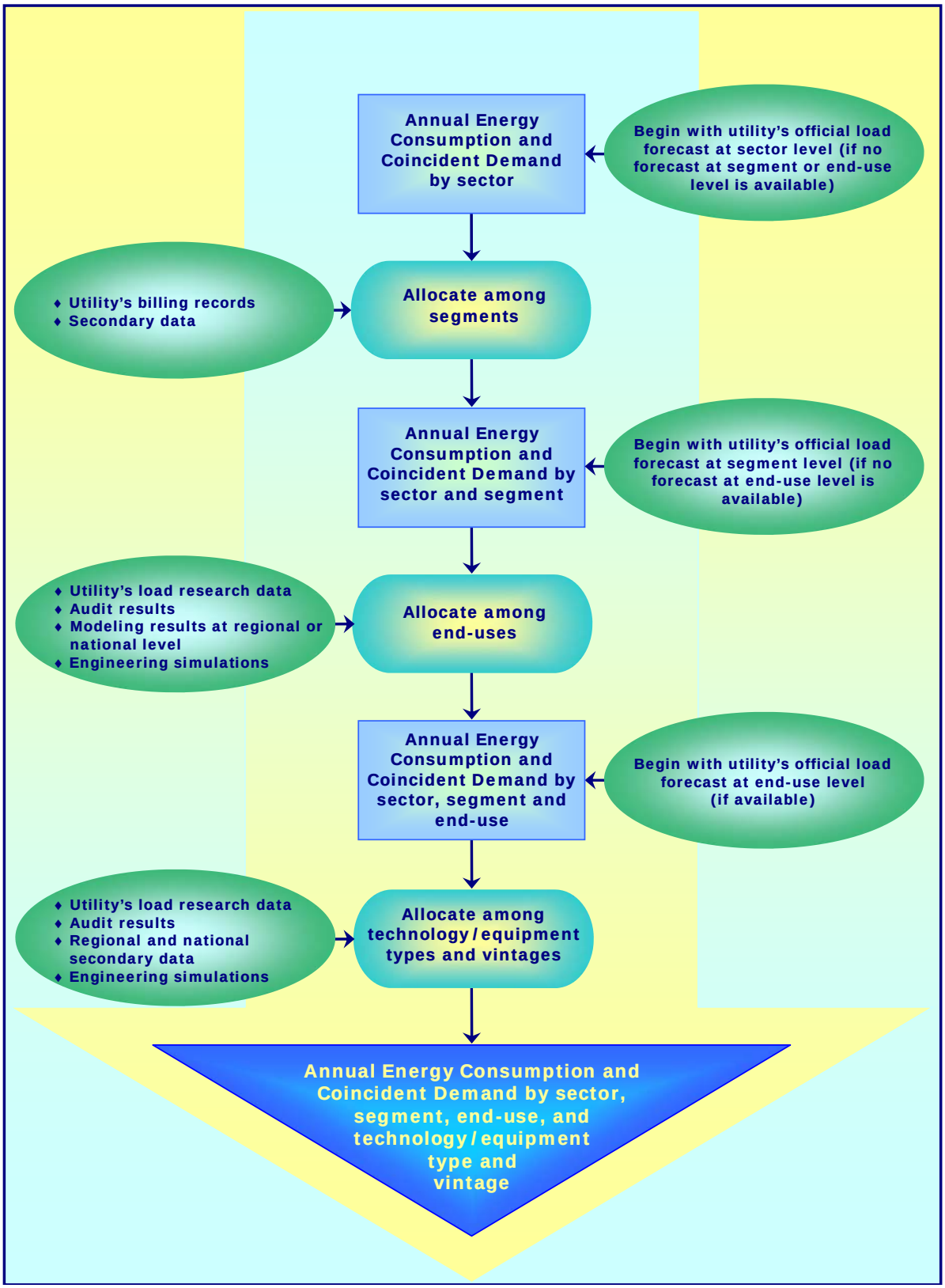


Figure 5-4
Establishing an EE Program Baseline Forecast: Top-Down Approach

If this official forecast is only available at the sector level, the annual energy consumption and peak demand for the sector are first allocated to the various segments by their percentage shares, as derived from the utility's billing records or building consumption data from secondary resources. Next, the segment-specific energy consumption and peak demand forecasts are allocated to different end-uses on the basis of end-use consumption data. Such data might be derived from a variety of sources such as load research data or on-site audit data obtained by a neighboring utility, results from end-use models obtained at the regional or national level, and other end-use data developed at the local or national level. Finally, the end-use forecasts can be allocated to the different technologies or equipment types and vintages if enough secondary data are available.

Hybrid Bottom-Up/Top-Down Approach

A hybrid bottom-up/top-down approach is appropriate when sufficient primary data are available at the equipment or technology level for specific end-uses and segments (e.g., motors in the industrial sector and lighting in the commercial sector). The annual energy consumption and peak demand for these end-uses and segments can be determined using a bottom-up approach, and a top-down approach can be used for all other end-uses and segments. Hybrid approaches can be used for determining the baseline forecast for all sectors.

Prototype Approach

Figure 5-5 illustrates a *prototype approach*, another approach that can be employed to establish baseline conditions, particularly in the residential and commercial sectors. The prototype approach is a variation of the bottom-up approach that integrates engineering simulation models into EE program analyses. Using these models, the energy consumption of prototypical buildings can be evaluated.

The first step in this type of analysis determines the prototypes to be studied. These prototypes can be representative of an entire segment or a sub-segment within a sector. Typically, prototypes are selected to analyze the most important customer segments (i.e., building types) in the utility's territory. The remaining segments can then be analyzed using a top-down approach.

The determination of the prototypes is also influenced by data availability. The availability of metered, whole-building hourly load shape data for a prototype provides an important means by which to quantify and benchmark the typical profile and amount of energy use for that building type. In other words, such data permit the reconciliation of the prototype simulation results to the energy and peak demand constraints of actual representative whole-building loads.

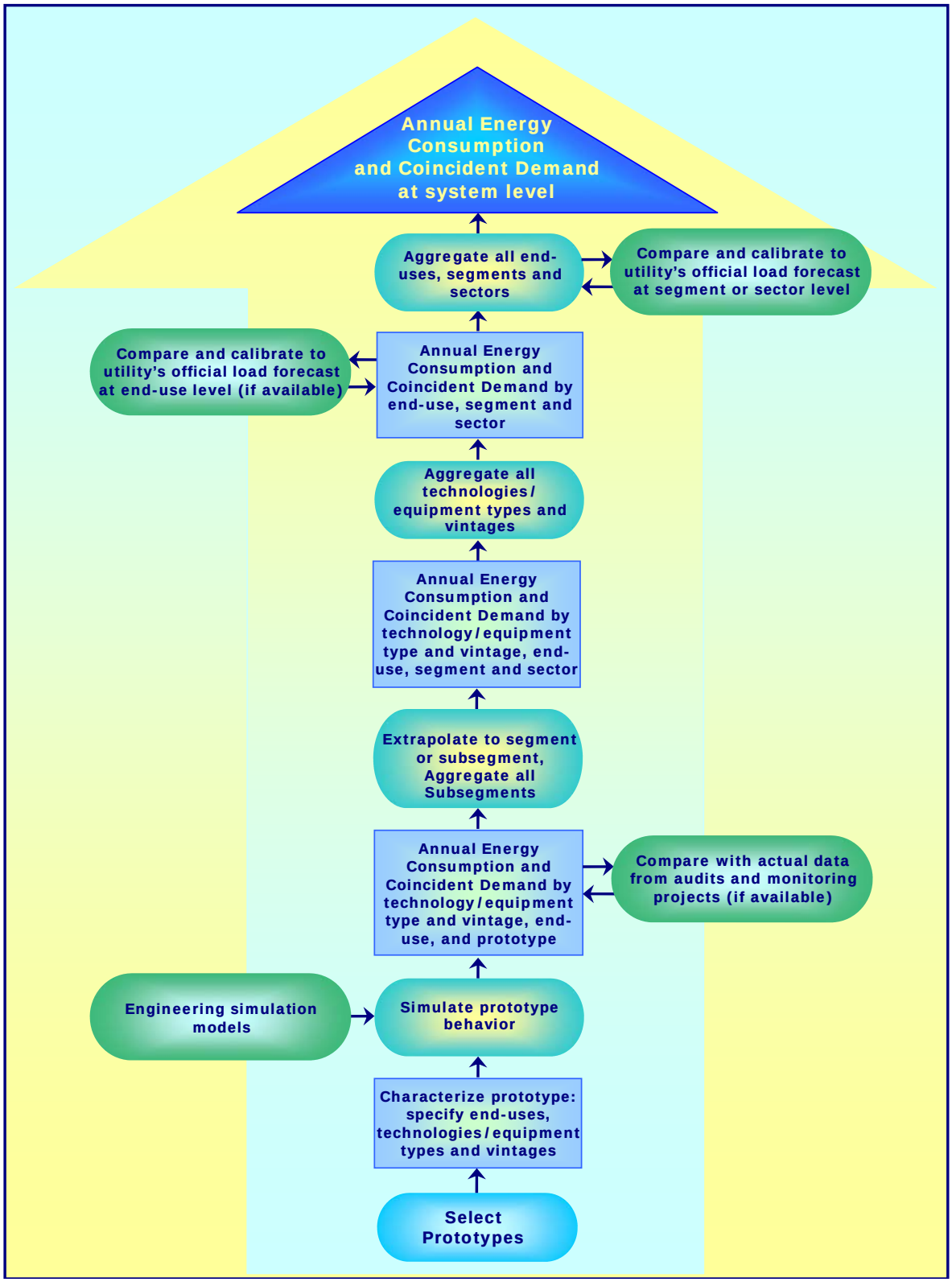


Figure 5-5
Establishing an EE Program Baseline Forecast: Prototype Approach

Once the prototypes are defined, their baseline characteristics must be determined. For each prototype, the major components affecting building energy use must be considered. These include:

- Building shell characteristics;
- Heating, cooling, and ventilation systems;
- Connected lighting loads, control types, and usage patterns;
- Connected equipment and appliance loads, and usage schedules, and
- Building operation and occupancy characteristics

The next step in the analysis involves running the baseline simulations using energy simulation models. One commonly employed model is DOE-2, used either directly or with user-interface software platforms such as eQUEST. The hourly results from the simulations are then processed into average monthly and peak day profiles for comparison with metered data, if available. From the results obtained for each prototype, baseline energy and peak demand forecasts at the end-use, segment, or sector level can be obtained. These values can be reconciled with the utility's official load forecast at the level that the forecast is available.

Baseline Forecasting Characteristics by Sector

Residential Sector Baseline Forecast

In some cases, there are enough primary or secondary data to develop the residential sector baseline forecast using the bottom-up approach. This approach requires accurate estimates of technology or equipment saturations and UEC values. Many utilities have conducted saturation studies and developed technology equipment saturation data for their service territories, and estimates of equipment UECs, if not already available for the utility, can be developed from secondary data. However, since most utilities use econometric models which typically result in load forecasts at the sector level, the calibration and comparison can only be done at that level. Even for the residential sector, most utilities do not use the bottom-up approach but rather the prototype or hybrid approaches.

Enough national and regional information is now available to make fairly accurate calculations of appliance UECs. The historical equipment capacity, efficiency, utilization, and product shipment data that are necessary for calculating base year UECs are available from trade organization such as the Association of Home Appliance Manufacturers (AHAM), the Air Conditioning and Refrigeration Institute (ARI), research organizations such as EPRI, the U.S. Department of Energy, and the national laboratories. Although data completeness varies, the information is often available as far back as 1972 and includes detail by product class within the major end-use categories. UEC forecasts rely on the equipment efficiencies mandated by federal appliance standards and on equipment capacity and utilization trends. Projections for appliances that are not subject to efficiency standards are more difficult to make since absent regulatory requirements to mandate higher efficiencies, manufacturers incorporate only those changes required to remain competitive in the market. The historical UECs for these appliances have not shown much variation and the savings potential for these appliances is limited. Therefore the

corresponding UECs are usually kept constant for the purposes of developing the baseline forecast.

Space heating and cooling UECs depend on local weather conditions and building construction practices. Therefore, they often require a more sophisticated analysis that uses computerized simulation models to estimate those UECs.

Seasonal UCDs can be determined by applying load factors to appliances' UECs and can be developed directly from some of the simulation models for heating and cooling applications. The load factors can be derived from the utility's load research studies or other appropriate load studies or load shape models.

The residential sector baseline forecast generally projects annual electric consumption and seasonal peak demands for all major end-uses of electricity, including heating, ventilation, and air conditioning (HVAC) equipment and appliances. Because the cost-effectiveness of building shell improvements depends on the combination of heating and cooling equipment, the baseline forecast typically addresses various heating and cooling configurations, such as:

- Non-electric heat with room air conditioning
- Non-electric heat with central air conditioning
- Heat pumps (such as air-source, ground-coupled, ground-water source, and dual fuel heat pumps)
- Electric heat with room air conditioning
- Electric heat with central air conditioning
- Electric heat with no space cooling

In addition, the following appliances are usually considered:

- Refrigerator
- Freezer
- Water heater
- Clothes washer
- Clothes dryer
- Range
- Swimming pool pump
- Miscellaneous

Energy use in the miscellaneous category, which consists largely of plug loads (that is, devices that are not hard-wired but rather plug into a building's electrical system), is growing at higher than historical rates because of the increasing presence of computers, cell phone chargers and other electronic devices. This growth must be properly accounted for in the baseline forecast. Figure 5-6 illustrates that for the U.S. as a whole, plug loads, including "TV/PC" and "other uses," are the only residential end-uses whose electricity intensity—expressed as kWh per

household—are expected to grow through 2030. These plug load categories are expected to grow from 35% of U.S. residential electricity consumption in 2005 to 43% in 2030.[39]

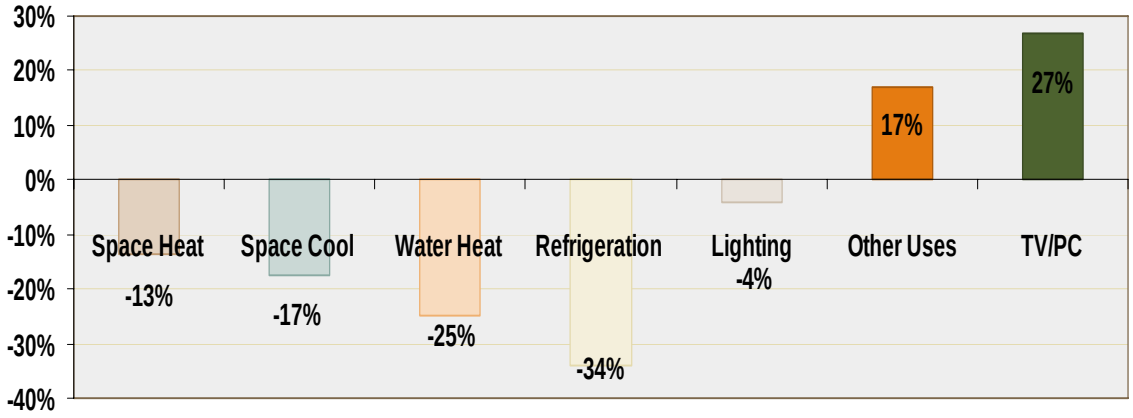


Figure 5-6
Change in Electricity Intensity of Major Residential End Uses (2005 – 2030) [40]

Projections are usually made separately for three types of dwelling units:

- Single family
- Multifamily
- Modular home

In addition, a distinction is made between new and existing homes/equipment. If more detail is desired, additional categories can be considered.

The Residential Energy Consumption Survey (RECS) and the Annual Energy Outlook (AEO), which are periodically published by the Department of Energy's (DOE's) Energy Information Administration (EIA), are excellent resources for historical and projected energy use data for residential buildings.

Commercial Sector Baseline Forecast

The diversity of commercial buildings, end-uses, and technologies often precludes a strict bottom-up approach because sufficient data are seldom available on saturation rates and energy consumption by technology. Forecast information is often only available at the sector or segment level. Some utilities may have detailed information such as audit results from their larger customers. In these cases it may be possible to develop the baseline using EUI and CLIs obtained directly from the utility, or from extrapolated secondary data.

[39] EIA Annual Energy Outlook 2007.
[40] EIA Annual Energy Outlook 2007, Table A4, page 142. Baseline electricity consumption for heating, cooling, and lightning intensity normalized on per sq. ft. basis; refrigeration and TV/PC/Set top/other uses normalized on per household basis.

Typically, because of limited data, a top-down approach, a prototype analysis, or a combination of both is employed to establish the commercial sector baseline forecast. Assumptions, expert opinion, and secondary data are often used in the baseline process to augment utility-provided data.

The commercial sector baseline forecast typically projects annual electric consumption and seasonal peak demand for major appliance-related end-uses, such as:

- Lighting
- Refrigeration
- Water heating
- Miscellaneous (including plug-loads such as office equipment)

And three weather-sensitive end-uses:

- Heating
- Cooling
- Ventilation

Projections are usually made for the following building types:

- Office
- Retail
- Grocery
- Restaurant
- Warehouse
- School
- College
- Health
- Miscellaneous

If more detail is desired, additional building types are considered. Typical examples include large and small and/or low-rise and high-rise office buildings instead of just office buildings, and fast-food and sit-down restaurants instead of just restaurants. Projections are usually made separately for new and existing buildings.

The EIA's Commercial Buildings Energy Consumption Survey (CBECS) and AEO reports are valuable sources of information on historical and projected energy use data for commercial buildings.

Industrial Sector Baseline

Industrial sector end-uses are generally more diverse than those of the residential and commercial sector, and sufficient data are seldom available to permit a strict bottom-up approach. Instead, a top-down approach is often employed to establish the industrial sector baseline forecast. Projections are usually made separately for each major industrial segment (three-digit NAICS code) present in the utility's service territory. The types of industries vary widely. For example, major industrial segments in the manufacturing industries (NAICS 31-33) include:

Table 5-1
Major Industrial Segments

Major Industrial Segments	
Food Manufacturing	Plastics and Rubber Products Manufacturing
Beverage and Tobacco Product Manufacturing	Nonmetallic Mineral Product Manufacturing
Textile Mills	Primary Metal Manufacturing
Textile Product Mills	Fabricated Metal Product Manufacturing
Apparel Manufacturing	Machinery Manufacturing
Leather and Allied Product Manufacturing	Computer and Electronic Product Manufacturing
Wood Product Manufacturing	Electrical Equipment, Appliance, and Component Manufacturing
Paper Manufacturing	Transportation Equipment Manufacturing
Printing and Related Support Activities	Furniture and Related Product Manufacturing
Petroleum and Coal Products Manufacturing	Miscellaneous Manufacturing
Chemical Manufacturing	

Segments in the agricultural industry are also important to consider.

For the top-down approach, annual energy use and seasonal peak demand are typically allocated by each of the end-uses appropriate to the industrial sector. The end-uses usually include:

- Motor drive
- Process heating
- Refrigeration
- Electrolytics
- Lighting
- Heating, ventilation, and air conditioning (HVAC)
- Miscellaneous

Allocations of end-use data is often accomplished using secondary sources such as the EIA, Lawrence Berkeley National Laboratory (LBNL), ACEEE, EPRI, and other databases and models. Considerable national and regional information is available on these end-uses for the various industrial segments. For example, the EIA publishes periodic reports on historical and projected energy end-use data for the industrial sector in its Manufacturing Energy Consumption Survey (MECS) and Annual Energy Outlook (AEO) documents. See the Resources section at the end of this chapter for specific secondary resources.

Example of Baseline Forecasting Results

Table 5-2 and Figures 5-7 through 5-9 illustrate sample baseline forecasting results. In this example, the planning horizon is the period 2010 to 2025. Table 5-2 shows energy and peak demand at the sector level. Figures 5-7 through 5-9 illustrate the breakdowns of energy and peak demand by end-use at the sector level for the residential, commercial, and industrial sectors, respectively. The segment level results for this example are not shown. However, the residential assessment considered single-family homes and multi-family dwellings. Fifty-four percent of total energy usage was attributable to single-family homes and multi-family dwellings accounted for the remaining 46 percent. In addition, 10 building types were evaluated for the commercial sector, with retail, hotels/resorts, offices, schools and restaurants being the predominant energy users. The principal energy-using segments in the industrial sector included food processing and pumping.

Table 5-2
Illustrative Baseline Forecast: Energy Use and Peak Demand by Sector

					Share of Total	
	2010	2015	2020	2025	2010	2025
Energy (GWh)						
Residential	3,202	3,517	3,763	3,952	39%	40%
Commercial	4,459	4,828	5,049	5,220	54%	53%
Industrial	562	608	636	658	7%	7%
Total	**8,224**	**8,953**	**9,449**	**9,830**	**100%**	**100%**
Peak Demand (MW)						
Residential	599	655	703	743	43%	45%
Commercial	707	759	794	827	51%	50%
Industrial	74	79	83	87	5%	5%
Total	**1,380**	**1,493**	**1,581**	**1,657**	**100%**	**100%**

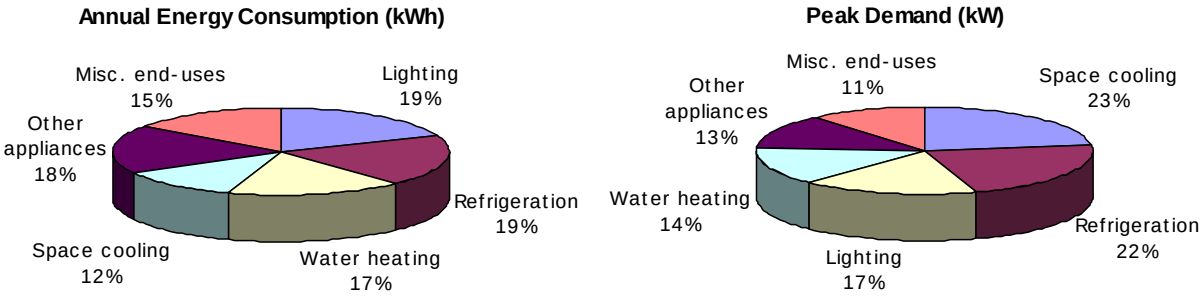


Figure 5-7
Illustrative Baseline: Residential Energy Use & Peak Demand by End-Use

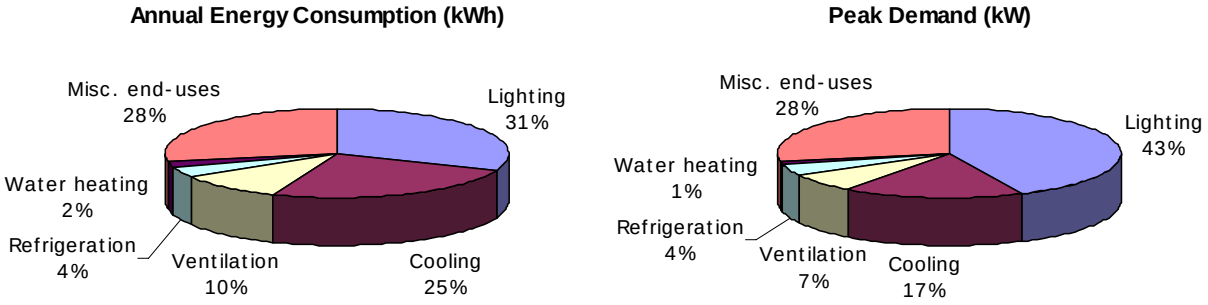


Figure 5-8
Illustrative Baseline: Commercial Energy Use & Peak Demand by End-Use

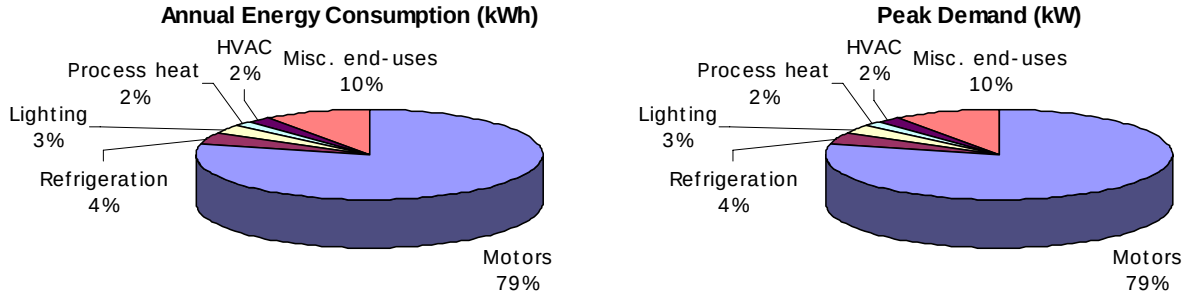


Figure 5-9
Illustrative Baseline: Industrial Energy Use & Peak Demand by End-Use

Summary and Resources

This chapter described EE program baseline forecasts and the different approaches that can be followed to define them, namely the bottom-up, top-down, and prototype approaches. It then presented the characteristics of baseline forecasts for the residential, commercial, and industrial customer sectors. The chapter also included an illustrative example of baseline forecasting results.

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6
SCREENING MEASURES

Introduction

The third step in the EE program process illustrated in Figure 6-1 is to screen EE measures.[41] This chapter describes how to identify measures that are of potential benefit to your customers and how to conduct a three-level screening process to select those measures that are more applicable to your service territory.

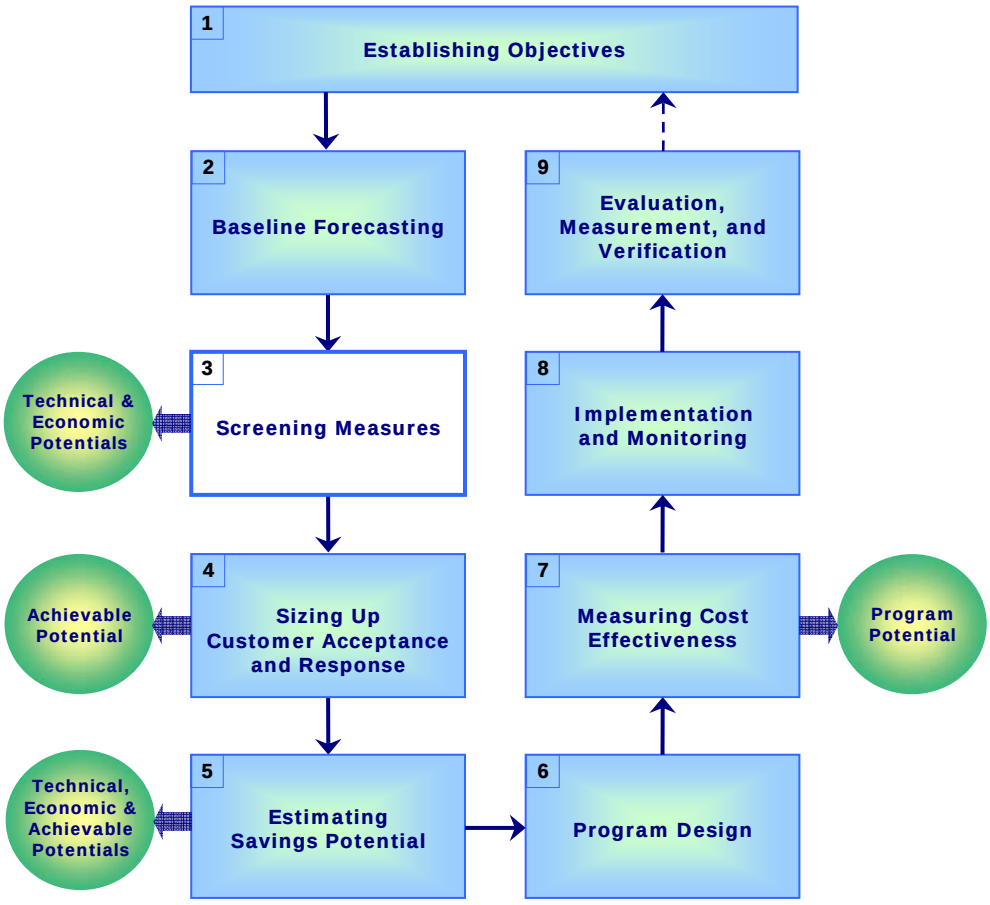


Figure 6-1
EE Program Process, Step 3: Screening Measures

[41] In the context of this document, "EE" refers to both energy efficiency/conservation and demand response.

The three-level process involves:

1. A preliminary screening step to identify measures worthy of more detailed characterization

A secondary screening step to identify measures to analyze in the potential assessment

An economic screening step to identify measures that pass the economic criteria

Completion of the first two levels of screening ultimately leads to quantification of the technical potential. Completion of the third level of screening leads to quantification of the economic potential.

EE Measures

For purposes of regulatory credibility, it is useful to create a comprehensive list of EE measures and technologies that are of potential benefit to electricity customers in your service territory. A representative sample of EE measures for the residential sector is presented in Table 6-1.

The list of potential measures can be developed from information on other utilities' EE program experience, as well as from numerous EE-related publications and resources. Programs such as ENERGY STAR®, which is a joint venture of the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Energy (DOE), and the U.S. Green Building Council's Leadership in Energy and Environmental Design (LEED) program are excellent sources of information on energy efficient equipment and building practices, particularly for the residential and commercial sectors. The American Council for an Energy Efficient Economy (ACEEE) is another useful resource for EE measures.

In addition to energy efficient technologies and practices, EE measures encompass time-based rate options, incentive-based strategies, and enabling technologies for demand response such as smart thermostats, smart appliances, or thermal energy storage systems. Time-based rate options, such as time-of-use (TOU), real time pricing (RTP), and critical peak pricing (CPP), better match retail prices with wholesale market costs, encouraging load reductions during high-priced peak periods. Incentive-based strategies such as direct load control (DLC), interruptible or curtailable (I/C) rates, demand bidding/buyback (DB/BB) options, emergency demand response (EDR) measures, capacity market programs (CAP), and demand control ancillary service (AS) markets offer incentives to participants for reducing peak loads during periods of system need or stress. Rate options coupled with enabling technologies can result in higher impacts than those obtained from innovative rates or technologies alone. The U.S. Demand Response Coordinating Committee (DRCC) is a good source of information on current policies and practices related to demand response.

The energy efficient and demand response technologies and practices being analyzed throughout the nation are changing rapidly as more and more utilities encourage adoption of such technologies. It is important to keep track of newly emerging measures by reviewing R&D and pilot programs.

Table 6-1
Sampling of Residential EE Measures

Building shell	Insulation on building envelope: ceilings, walls, floors, foundations, slabs
	Double- or triple-pane windows
	Low-emissivity windows
	Window films
	Interior shades or thermal drapes
	Storm or thermal door
	Caulking and weatherstripping
	Duct insulation/repair
	Radiant barriers
Cooling	High-efficiency central air conditioner
	Servicing central air conditioner
	Early replacement of old central air conditioner
	Evaporative cooler
	Precooler
	High-efficiency room air conditioner
	Servicing room air conditioner
	Removal of unneeded room air conditioner
	Early replacement of old room air conditioner
	Fans: attic, whole-house, ceiling
	Displacement ventilation
	Natural ventilation
	Shade trees, awnings or pergolas
Heating	Variable-speed furnace
	Active solar space heater
	Two stage condensing gas furnace
	Electrically-heated floors
	Zoned resistance heating
Cooling & heating	Air filter replacement
	Thermostat control: set-back, set-up
	Heat pumps: air-source, ground-coupled, or groundwater source
	Dual fuel heat pump
	Multizone heat pump
	Room heat pump
	Servicing heat pump
Lighting	High efficiency fluorescent lamps and ballasts for general illumination
	Compact fluorescent lamps for task lighting
	LED task lighting
	Lower-wattage incandescent lighting
	Advanced lighting controls including dimmers, photo sensors, motion detectors
	Light scheduling
	High intensity discharge lamps
	Servicing lighting
	Skylights
Water heating	High-efficiency water heater
	Early replacement of old water heater
	Solar water heater
	Heat pump water heater
	Tankless water heater
	Heat recovery water heater
	Hot water pipe insulation
	Low-flow shower heads
	Faucet aerators
	Water heater timer or advanced controls
	Water heater thermostat setback
	Water heater cycling
	Water saving appliances: dishwasher, clothes washer
	Direct/distributed control
	Efficient water heater operation
Appliances	High efficiency appliances: dishwasher, clothes washer, clothes dryer, refrigerator, freezer, cooktop and oven
	Heat pump clothes dryer
	Duct heat recovery clothes dryer
	Induction cooktop
	Refrigerator or freezer antisweat switch
	Early replacement of appliances
	Servicing appliances
	High efficiency electronics: entertainment devices, computer, monitor, printer, fax machine
	Minimize standby losses
	High-efficiency pool pump
	Pool cover
	Pool pump timer/ controls
	Efficient appliance operation
	Appliance operation during off-peak hours
Demand response	Innovative rates and strategies
	Time of use rate (TOU)
	Real time pricing (RTP)
	Critical peak pricing (CPP)
	Direct load control program
	Enabling equipment
	Smart meters
	Smart thermostats
	Smart appliances
	Thermal energy storage
	Advanced notification of power or pricing events (internet, pager, cell phone, etc.)
	Load controls
	Two-way communications

Once the list of potential EE measures has been created, several levels of screening are typically performed to identify those measures that are applicable to the utility's service territory and are more effective from a technical, market, and economic perspective. Figure 6-2 illustrates a three-level screening process.

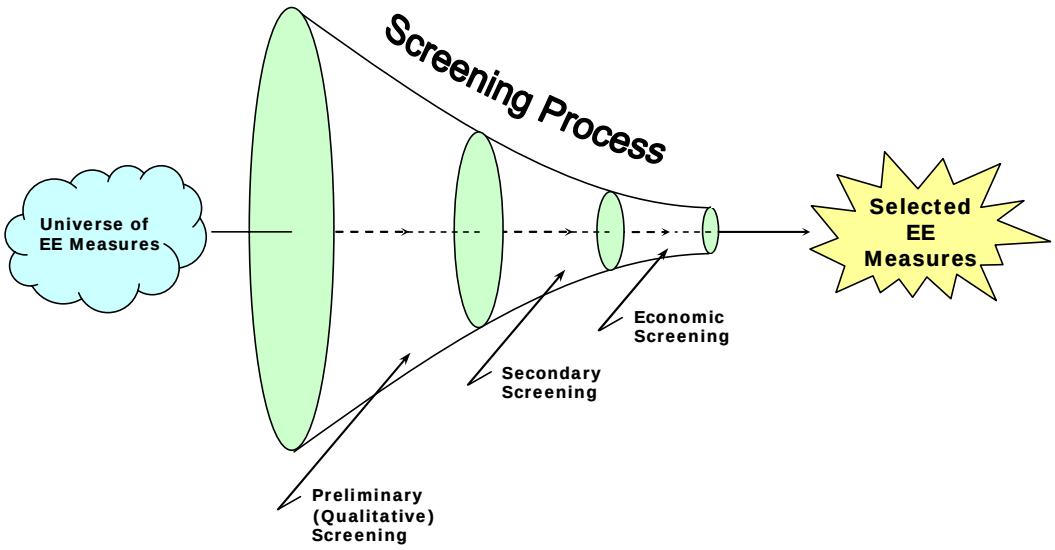


Figure 6-2
Conceptual Screening Process for Selecting EE Measures

The following sections describe the screening process in more detail. After the screening is performed, the expected customer response to the selected EE measures is evaluated in order to determine the achievable potential of the measures (see Chapter 7).

Preliminary (Qualitative) Screening

The first screening of EE measures considers a series of qualitative criteria designed to assess the applicability of the EE measures to conditions unique to the utility's territory. The purpose of the qualitative screening is to produce a list of measures that merit detailed analysis with a reasonable expenditure of analytic effort. Without this step, the analyst may be overwhelmed by myriad possible EE measures, and might risk performing detailed analyses on measures inappropriate for the utility's circumstances. The qualitative screening criteria vary by utility but may include the following:

- **Immaturity:** Is the measure in the development stage so that it will not be commercially available or fully tested within the defined EE program assessment horizon?
- **Poor utility match:** Is the measure incompatible with the climate, building stock, or equipment that is typical of the utility's territory?

- **Better measure available:** If more than one measure addresses a specific inefficiency in equipment, operation, or building envelope, is another measure clearly equivalent in function and more cost-effective?
- **Environmental and health concerns:** Does the measure present any potential environmental or health concerns?

A sample screening of some residential measures is presented in Table 6-2.

Table 6-2
Qualitative Screening: Sampling of Residential EE Measures [42]

Qualitative Screening Criteria					
EE Measure	**Technological Immaturity?**	**Poor utility match?**	**Better measure available?**	**Environmental and health concerns?**	**Pass ?**
Building Shell					
Ceiling and wall insulation					Y
Foundation insulation					Y
Floor insulation					Y
Slab insulation		Y[1]			N
Double- or triple-pane windows					Y
Low-emissivity windows					Y
Window films					Y
Interior shades or thermal drapes			Y[2]		N
Caulking and weather-stripping					Y
Duct insulation/repair					Y
Cooling					
High-efficiency central AC					Y
Servicing central AC					Y
Evaporative cooler					Y
Early replacement of old central AC					Y

Notes:
[1] The majority of homes in the utility's territory are not built directly on a slab.
[2] Window films are a better, more reliable measure than interior shades and drapes.

Screening matrices for a particular category of EE measure (e.g., lighting, water heating, demand response, etc.) can also be generated under each of the market segments and sub-segments for which baseline estimates have been developed to illustrate the range of applicability of the measures. For some measures, it may be possible to further disaggregate the applicability criteria by the type of end-use for a particular market sub-segment.

[42] Only affirmative responses are indicated; numbered notes 1 and 2 provide explanations.

However, for most EE options such disaggregation is not possible and one needs to consider the overall applicability of the measure for the particular market sub-segment. Tables 6-3 and 6-4 show screening matrices of demand response measures for single family homes and commercial buildings, respectively. The single family home example depicts disaggregation down to the end-use level, while the commercial building example illustrates disaggregation down to building type.

Table 6-3
Applicability Screening: DR Measures in Single Family Homes by End-Use

Type of End-use	Incentive-based programs						Time-based rate programs[1]		
	DLC[2]	I/C rates[3]	DB/BB[3]	EDR[3]	CAP[3]	AS[3]	TOU	CPP	RTP
Lighting									
Heating	✓								
Cooling	✓								
Plug									
Water heating	✓								
Exterior									
Overall		NA	NA	NA	NA	NA	✓	✓	✓

DLC = Direct Load Control; I/C = Interruptible/Curtailable; DB/BB = Demand Bidding/Buyback; EDR = Emergency Demand Response; CAP = Capacity Market Programs; AS = Ancillary Services; NA = Not Applicable

Notes:

[1] All three types of time-based rate programs are applicable to residential customers. Since these programs result in an overall reduction in demand, it may be difficult to estimate demand reductions associated with specific end-use types.

[2] DLC programs are commonly used with residential customers to cycle the operation of specific end-use appliances.

[3] Typically, these demand response measures are not offered to residential customers.

Table 6-4
Applicability Screening: DR Measures by Commercial Building Type

Type of end-use	Incentive-based programs						Time-based rate programs		
	DLC	I/C rates	DB/BB	EDR	CAP	AS	TOU	CPP	RTP
Large office		✓	✓	✓	✓	✓	✓	✓	✓
Medium office	✓	✓					✓	✓	✓
Large retail		✓	✓	✓	✓	✓	✓	✓	✓
Medium retail	✓	✓					✓	✓	✓
Grocery	✓	✓	✓	✓	✓	✓	✓	✓	✓
Large hotel		✓	✓	✓	✓	✓	✓	✓	✓
Medium hotel	✓	✓					✓	✓	✓
Hospital							✓	✓	✓
Nursing home	✓						✓	✓	✓
Large school		✓	✓	✓	✓	✓	✓	✓	✓
Medium school	✓	✓					✓	✓	✓
College		✓	✓	✓	✓	✓	✓	✓	✓
Restaurant	✓						✓	✓	✓
Warehouse	✓	✓	✓	✓	✓	✓	✓	✓	✓
Small commercial	✓						✓	✓	✓
Misc. commercial	✓	✓	✓	✓	✓	✓	✓	✓	✓

DLC = Direct Load Control; I/C = Interruptible/Curtailable; DB/BB = Demand Bidding/Buyback; EDR = Emergency Demand Response; CAP = Capacity Market Programs; AS = Ancillary Services

EE Measure Characteristics

Once EE measures appropriate to the utility's conditions have been selected, information on their relevant characteristics needs to be compiled. The information generated for each measure that passes the qualitative screen typically includes:

- Description
- Operating history
- Annual energy consumption impact
- Peak demand impacts (winter and summer)
- Load shape impacts
- Useful life
- Incremental costs (operating, capital, and installation)
- Expected changes in cost and performance over time, and
- Environmental effects

The measure characterization usually starts with a full technical description of what the measure accomplishes; the building types, industries, and processes where it is typically installed; and the way in which the measure is typically implemented. The measure's operating history permits an assessment of the measure's "track record."

Estimates of the measure's energy, demand, and load shape impacts are also developed. These estimates are categorized to the extent possible by segments within the sectors. For example, energy savings estimates for efficient air conditioners differ between single-family and multifamily dwellings. Several methods can be employed to estimate the energy and demand impacts corresponding to different EE measures. The impacts can be estimated directly using engineering or statistical methods, or they can be obtained from databases developed with secondary data.

For non weather-sensitive end-uses, simple engineering calculations can be performed to estimate the energy consumption savings. For example, the energy and peak demand consumption savings obtained when replacing an incandescent lamp with a compact fluorescent lamp can be estimated as:

*Energy savings = Reduction in wattage * Operating hours*

*Peak demand impact = Reduction in wattage * End-Use or Class Coincidence Factor*

For weather-sensitive end-uses, computerized engineering simulation models such as DOE-2 based systems can be used to estimate the energy consumption, load shape, and peak demand impacts of EE measures. The models simulate the energy consumption behavior of prototype dwelling or building types with and without EE measures.

Simulation models also take into account interactive effects of EE measures that are otherwise difficult to quantify with simple calculations. For example, replacing an incandescent lamp with a compact fluorescent lamp not only results in lighting energy savings, but also affects cooling and heating loads—cooling requirements are decreased by the use of compact fluorescent lamps, while heating requirements are increased. Energy simulations models readily take these important interactions into account.

Econometric models or secondary data on customer response can be used to estimate the peak demand impacts attributable to time-based rates and other demand response measures. There is a growing body of data to call upon as more and more demand response programs are now being carried out at the pilot-scale and full-scale levels. The impacts are often presented in terms of absolute or relative load impacts (measured in kilowatt or percent load reduction) or in terms of price elasticity. Price elasticity provides a normalized measure of the intensity of customer load changes in response to price circumstances. It is especially applicable to time-varying rates or demand response programs that induce load modifications directly in response to price changes. It is defined as the percentage change in usage for a one-percent change in price.

Measure lifetimes and incremental costs must also be determined. Several sources of information can be used to estimate total and incremental costs for EE measures. Some of these sources include general cost information for residential, commercial, and industrial sector EE measures. These costs data may need to be adjusted to reflect the specific conditions of the utility's service

territory. Other sources of information include cost data handbooks like those published by RSMeans and Grainger, and data from the cost databases of other utilities. This cost information typically needs to be augmented by a telephone survey of vendors and distributors of energy-efficient equipment in the utility's service territory. The cost information is an essential requirement for the economic screening step described subsequently.

Finally, the environmental effects related to each EE measure are sometimes assessed. Examples of such effects include indoor air quality, the creation or reduction of solid waste, the use or destruction or hazardous materials, and the use or capture of chlorofluorocarbons (CFCs).

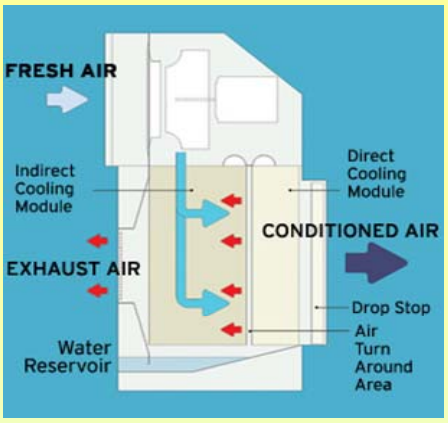
Organizations such as DOE, ACEEE, DRCC, the California Energy Commission (CEC), the National Renewable Energy Laboratory (NREL), the American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE), and several utilities have published documents that include information on EE measures and characteristics.

Figure 6-3 illustrates the type of information typically compiled for each EE measure that passes the qualitative screening.

Indirect-Direct Evaporative Cooling (IDEC) System

Description

IDEC systems rely on 2-stage evaporative cooling. In the first stage, the outdoor air passes through an indirect cooler, which lowers the temperature without adding humidity. The cool, dry air then enters the second stage—the direct evaporative cooler—where it is cooled down further as it picks up moisture from a wet medium. Combining these two cooling techniques enables the supply air to be cooled below the outside air wet bulb temperature. One new design of IDEC (see figure) uses a single blower that pulls in outside air, and directs roughly 70% of it through the dry side of a heat exchanger that uses 14-inch thick media. The remaining 30% of the outdoor air flows through the wet side of the counterflow heat exchanger where it is cooled and picks up moisture before entering the outdoors. The counterflow heat exchanger constitutes the first indirect evaporative cooling stage. The 70% air flow stream, now cold but still dry, then enters the second direct evaporative stage where it cools down further and also picks up some moisture before entering the indoor space. Both the indirect and direct evaporative stages produce water. This water gathers in a single reservoir which is drained and flushed automatically.



Air Flow Patterns in a New IDEC System.
Source: Speakman CRS (Need permission)

Applications

IDEC systems can be used to retrofit conventional compressor-based AC units or direct evaporative cooling systems in residential homes and commercial buildings. In addition, indirect-direct evaporative cooling systems can be readily installed in new construction. The greater the difference is between the air's dry bulb temperature and wet bulb temperature, the greater the evaporative cooling potential is. IDEC systems perform best in climates where the mean coincident wet bulb temperature remains below 70°F. As a result, IDEC systems are most appropriate for the western U.S. They are not appropriate for use in humid climates.

Operating History / Market Penetration

The evaporative cooling market is currently small in the U.S., with only a few percent of homes using evaporative cooling. Evaporative cooling has achieved higher penetration in homes (particularly mobile homes) in western states. The market penetration for IDEC is smaller, since most evaporative cooling systems are either direct or indirect evaporative systems. The penetration of IDEC is expected to increase substantially during the next 5 to 10 years, especially in hot and dry climates, as the awareness of the great energy savings provided by this cooling technology increases.

Annual Energy Impact

Data from demonstrations and simulations indicate that replacing conventional compressor-based air conditioning (DX) with IDEC in residential homes typically yields energy savings of 80% to 90% in hot and dry climates. The energy savings are lower in temperate climates. The following table summarizes energy savings derived from simulations of highly-efficient 1,800-ft^2 homes in hot and dry climates.

City	Annual Cooling Energy DX	Annual Cooling Energy IDEC	Annual Energy Saved (%)
Albuquerque, NM	2,487	2,153	87%
Cheyenne, WY	1,773	1,485	84%
Denver, CO	1,935	1,656	86%
Las Vegas, AZ	4,722	4,225	89%
Phoenix, AZ	6,043	5,469	90%
Salt Lake City, UT	2,839	2,483	87%

Figure 6-3
Sample EE Measure Attributes: Indirect-Direct Evaporative Cooling (part 1)

Indirect-Direct Evaporative Cooling (IDEC) System (continued)

Peak Demand / Load Shape Impact

A conventional residential DX system rated at 12-SEER has a peak demand of about 3 kW, while an IDEC system of comparable size has a peak demand of about 0.5-0.7 kW. As a result, IDEC systems can reduce peak demand by as much as 75-85% relative to conventional AC units.

Costs, Lifetime, and Payback

The costs for IDEC systems are comparable to conventional central AC systems. For example, installed costs for conventional split system AC units are approximately $3,300. Total installed costs for efficient IDEC cooling systems are on the order of $2,500 to $3,500. Because of the significant energy savings, lifetime costs for IDEC cooling systems over a 20-year lifetime are typically half of those for comparable compressor-based cooling systems. For example, one study estimates lifetime costs for a residential IDEC cooling system to be $5,500 in the Southwest. The lifetime costs for a comparable conventional AC system would be double. The simple payback period for replacing conventional AC units with IDEC systems ranges from 7 to 15 years. In new construction, the incremental cost for an IDEC system relative to conventional AC is very small, so an IDEC system pays for itself immediately.

Expected Changes in Cost and Performance

Hard water may cause scaling of heat exchanger surfaces, which in turn, will affect the cooling performance. When water evaporates, impurities in the water fall down into the water basin. To address the scaling issue, make-up water periodically or continually replaces bled-off water. Treatment of water may be required in regions with hard water.

Environmental Effects

IDEC systems provide environmentally-friendly cooling because they do not use CFCs. In addition, IDEC systems bring 100% fresh air into the space, thereby improving indoor air quality. In addition, the direct evaporative stage of the cooling system acts as a filter to remove particulates from the supply air, improving indoor air quality further.

Information Sources

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Development of an Improved Two-Stage Evaporative Cooling Systems, California Energy Commission, 2004. 500-04-016.

Larry Kinney, "Modern Evaporative Coolers," *HOME ENERGY*, September/October 2005.

Best Practices Awards Program, UC/CSU Sustainability Conference, Santa Barbara, June 2006.

Resources for IDEC

California Energy Commission, www.cec.org.

Lawrence Berkeley National Laboratory, www.lbnl.edu.

Southwest Energy Efficiency Project (SWEEP), www.swenergy.org.

Figure 6-4
Sample EE Measure Attributes: Indirect-Direct Evaporative Cooling (part 2)

Secondary Screening

In some cases a secondary screening is performed. The secondary screening addresses additional criteria for individual measures, which may include:

- **Non-quantifiable (savings variance):** Are the costs and impacts of the measure non-quantifiable or quantifiable with very low reliability so that an economic evaluation is not possible or reasonable? Measures with impacts and costs that cannot be clearly quantified but are generally acceptable can be good candidates to include in customized programs. These measures should no be excluded from further analysis; they can be passed directly to the program design stage for further evaluation.
- **Poor customer acceptance***:* Does the measure reduce the quality of the energy-service provided to the customer to the point that customers are unwilling to implement it in important markets?

The secondary screening may also revisit some of the preliminary screening criteria in more detail. Some utilities combine the preliminary and secondary screening steps.

The screening criteria used in the secondary step help to screen out measures that are difficult to quantify and/or may be hard to market to customers except in niche markets. Such measures may still be viable and could be packaged in customized programs, but will not be included in the detailed potential assessment.

Figure 6-5 summarizes sample results from a secondary screening of compact fluorescent lamps (CFLs) in a template form. In this example, the CFL measure has already passed the preliminary qualitative screening and been characterized using the approach described in the preceding sections of this chapter. The secondary screening results show that this measure passes the screen and will continue to the next step.

Compact Fluorescent Lamps

Description

Compact fluorescent lamps consist of an electronic or magnetic ballast and a twin tube or quad tube lamp. They are designed to replace standard incandescent lamps and often require only 25% to 30% of the energy required by incandescent lamps to produce the same lumen output. Integral compact fluorescent lamps have the ballast integrated into the base of the lamp and have a standard screw-in base, which permits straightforward installation into existing incandescent fixtures.

Secondary Screening

Applicability to Utility	Compact fluorescent lamps are applicable to lighting needs in the utility's service territory. They can be readily installed in new construction or to replace incandescent lamps in existing buildings.
Technological Maturity	Compact fluorescent lamps are commercially available. They are sold in a wide variety of locations, including hardware stores and supermarkets. The efficiency and sophistication of compact fluorescent lamps continues to improve, with newer technologies having dimming capabilities.
Market Maturity	Compact fluorescent lamps are currently supported by the necessary service industry. They have been available in the lighting market for a number of years, but there is still a great potential for further implementation.
Acceptability to Consumers	Compact fluorescent technology is continuously improving making products more appealing to consumers. Some consumers (particularly residential) avoided early products due to limitations in light quality and color, flicker, dimming ability, and expense. Newer generation products should increase acceptability.
Quantifiable Demand, Energy and Cost Impacts	The demand, energy, and cost impacts of compact fluorescent lamps as replacements for incandescent lamps are straightforward to quantify. The impacts will be estimated using the customer segment prototypes and a DOE-2-based model. The savings in energy use and cost can be 70 to 75%.
Non-Energy Benefits	Some of the non-energy benefits of compact fluorescent lamps include: Roughly 70% less heat output than incandescent lamps (leads to safer operation in addition to reduced cooling load) Increased lamp life (up to 10 times the life of incandescent lamps) Reduced greenhouse gas emissions

Recommendation

Based on the results of the qualitative screening, we propose to include compact fluorescent lamps in further detailed analysis. They are applicable to the utility's service territory, they are commercially available with the potential to achieve greater penetration, they are increasing in consumer acceptability, and they have quantifiable energy and cost benefits, as well as non-energy benefits.

Figure 6-5
Illustrative Secondary Screening Results: Compact Fluorescent Lamps

After the secondary screening step, the analyst will have enough information to determine the *technical potential*. The technical potential represents the maximum potential energy savings and/or demand impacts that are technically possible for a given EE measure in a given application, without consideration to economics and customer response. See Chapter 8 for more detail on estimating the technical potential. In some cases, utilities stop here and then leap-frog to Step 6: Program Design (see Figure 6-1). In other cases, utilities proceed to the next level of screening described below.

Economic Screening

To screen out uneconomical EE measures, all measures passing the first two levels of screening described previously can be screened for their economic cost-effectiveness by using a simple test that yields an order-of-magnitude cost-effectiveness result. Usually, a simplified version of either the Participant Test or the Total Resource Cost (TRC) Test is used. For this type of preliminary economic screening analysis at the measure level, the effects of participation rates as well as program administration and delivery costs are ignored. That is, it is assumed for the time-being that participation rates and administration/delivery costs will not preclude the measure from passing on to further analysis. In essence, participation rates and administration/delivery costs are given the benefit of the doubt as they relate to the cost-effectiveness of the measure. If the measure passes the economic screen under these circumstances, it moves forward in the analysis.

The next steps described in subsequent chapters include bundling EE measures into programs and/or delivery mechanisms. When the more detailed cost-effectiveness analysis is done at the program level, participation rates and administrative/delivery costs are accounted for and the economics of the program are assessed from all test perspectives—Participant, TRC, Ratepayer Impact (RIM), Utility Cost, and Societal Cost (see Chapter 10).

The simplified Participant Test compares the quantifiable benefits of each EE measure to the costs of the measure from the perspective of a typical participant. The benefits include reduced energy costs, avoided appliance costs, and operation and maintenance (O&M) savings. The costs typically include bill increases, incremental capital and installation costs, and O&M cost increases.

The simplified TRC Test compares the quantifiable benefits of each EE measure with the measure's costs from the perspective of the utility and its ratepayers as a whole. The benefits include avoided marginal costs of energy and capacity and avoided operation and maintenance (O&M) costs. The costs consist of incremental capital and installation costs and O&M costs.

In determining the lifetime benefits, the energy and demand benefits are obtained by multiplying the annual energy savings and demand reductions by the participant's energy rates (for the simplified Participant Test) or by the utility's avoided costs (for the simplified TRC Test). The benefits are then typically discounted to a present value equivalent basis and compared to the measure's lifetime costs. The EE measure savings, incremental cost, and lifetime are obtained as part of the characterization of the EE measures described in earlier in this chapter.

The ratio of lifetime benefits to costs is used to determine the economic feasibility of the candidate measures. Measures with a benefit-to-cost ratio significantly greater than 1 pass the economic screen, and those with a ratio significantly less than 1 fail the screen. Measures with marginal benefit-cost ratios (for example, ranging between 0.8 and 1.3) may be considered to have passed or failed, based on the preferences of the utility's staff. Figure 6-6 shows results from an economic screening of a heat pump water heater using the Participant Test. Figure 6-7 presents results from an economic screening of several measures using the TRC Test.

Heat Pump Water Heater

Single-Family House, Existing Vintage

Base Case = Standard Electric Water Heater (Energy Factor =0.83)

Efficiency Case = Heat Pump Water Heater (Energy Factor =2.0)

- Unit impact = 1,591 kWh/yr per water heater; 0.358 kW per water heater
- Lifetime = 9 years
- Discount rate = 4.6%
- Inflation rate = 1.6%
- Cost of energy = $0.2215/kWh
- Measure first cost = $1,512 per water heater
- Present value of lifetime savings $2,870 per water heater
- Present value of lifecycle costs $2,288 per water heater
- B/C Ratio = 1.25
- Pass economic screen? = YES

Figure 6-6
Sample Economic Screening, Simplified Participant Test (HPWH)

Single Family Home
Existing Building
Electric Space Heating and Water Heating
Location: Oregon

End-Use	Energy Efficiency Measure	Baseline Level	Efficiency Level	Full or Incremental Cost	Measure Costs for Screening [$ 2006]				Lifetime Benefits ($ 2006)				
					Material Costs	Labor Costs	Lifetime O&M Costs	Total Costs [$ per unit]	Electric		Gas		Total [$ per unit]
									Peak Demand	Energy	Demand	Energy	
Heating/ Cooling	Heat Pump - Cold Climate Heat Pump	HSPF=6.8; SEER=10	HSPF=9.6;SEER=16	Full	$3,553.00	$1,628.80	$1,351.36	$6,533.16	$1,823.98	$721.55	$0.00	$0.00	$2,545.53
HVAC-Other	Ducting, Repair and Sealing	Existing Duct Condition	Repair and Sealing	Full	$104.50	$407.20	$0.00	$511.70	$2,774.27	$559.89	$0.00	$0.00	$3,334.15
Building Envelope	Doors, Storm and Thermal	No Storm Door	Install Storm Door (R-1)	Full	$404.54	$74.23	$0.00	$478.77	$12.77	$20.04	$0.00	$0.00	$32.81
		Standard Door	Install Thermal Door (R-5)	Full	$528.74	$74.23	$0.00	$602.97	$25.54	$40.27	$0.00	$0.00	$65.82
Building Envelope	Infiltration Control (caulk, weather strip, etc.)	Existing Infiltration Conditions	Install Caulking & Weatherstripping	Full	$79.63	$284.02	$0.00	$363.65	$224.40	$431.70	$0.00	$0.00	$656.10
Building Envelope	Insulation, Ceiling	R-0	R-11	Full	$0.15	$0.73	$0.00	$0.87	$2.30	$2.73	$0.00	$0.00	$5.03
		R-11	R-13	Incremental	$0.03	$0.00	$0.00	$0.03	$0.08	$0.12	$0.00	$0.00	$0.20
		R-13	R-19	Incremental	$0.08	$0.00	$0.00	$0.08	$0.16	$0.23	$0.00	$0.00	$0.39
		R-19	R-25	Incremental	$0.16	$0.00	$0.00	$0.16	$0.08	$0.13	$0.00	$0.00	$0.21
		R-25	R-30	Incremental	$0.14	$0.00	$0.00	$0.14	$0.05	$0.07	$0.00	$0.00	$0.13
		R-30	R-38	Incremental	$0.13	$0.00	$0.00	$0.13	$0.03	$0.08	$0.00	$0.00	$0.11
		R-38	R-49	Incremental	$0.20	$0.00	$0.00	$0.20	$0.05	$0.07	$0.00	$0.00	$0.12
Lighting	High Pressure Sodium Lamps, Outdoors	150 W Incandescent	50 W HPS Lamp	Full	$23.36	$5.09	$0.00	$28.45	$0.00	$69.55	$0.00	$0.00	$69.55
Lighting	Outdoor Lighting - Photosensor Control	No Photosensor Control	Install Photosensor Control	Full	$16.09	$40.21	$0.00	$56.30	$0.00	$72.87	$0.00	$0.00	$72.87
Water Heating	Faucet Aerators	4.0 GPM	2.5 GPM	Full	$5.31	$5.09	$0.00	$10.40	$0.00	$73.03	$0.00	$0.00	$73.03
Water Heating	Pipe - Hot Water, Insulation	No Pipe Insulation	Install Insul (R-4)	Full	$3.19	$21.38	$0.00	$24.56	$0.00	$128.67	$0.00	$0.00	$128.67
Water Heating	Showerheads, Low-Flow	4.5 GPM	2.5 GPM	Full	$14.86	$10.18	$0.00	$25.04	$37.49	$166.34	$0.00	$0.00	$203.83
Water Heating	Water Heater - Electric, High Efficiency	EF=0.83 or lower	EF=0.86	Incremental	$50.96	$0.00	$0.00	$50.96	$0.00	$67.97	$0.00	$0.00	$67.97
		EF=0.86	EF=0.90	Incremental	$99.20	$0.00	$0.00	$99.20	$32.09	$83.35	$0.00	$0.00	$115.45
		EF=0.90	EF=0.92	Incremental	$66.13	$0.00	$0.00	$66.13	$0.00	$39.20	$0.00	$0.00	$39.20
Water Heating	Water Heater, Tank Blanket/Insulation	No Tank Insulation	Install Insul. (R-6.9)	Full	$14.85	$20.36	$0.00	$35.21	$37.49	$206.63	$0.00	$0.00	$244.12
Water Heating	Water Heater, Thermostat Setback	No T-Stat Setback	Install Programmable Water Heater T-Stat.	Full	$74.27	$50.90	$0.00	$125.17	$37.49	$206.63	$0.00	$0.00	$244.12
Water Heating	Water Heating, Drain Water Heat Recovery	No Heat Recovery	Install Drain Water Heat Recovery	Full	$191.11	$223.96	$0.00	$415.07	$74.98	$386.59	$0.00	$0.00	$461.57
Appliances	Clothes Washer, Energy Star or better	Std. Top-Load Wash.	NAECA Std. Top-Load.	Incremental	$84.94	$0.00	$0.00	$84.94	$0.00	$46.14	$0.00	$0.00	$46.14
		NAECA Std. Top-Load.	Energy Star Top-Load.	Incremental	$350.37	$0.00	$0.00	$350.37	$128.37	$466.63	$0.00	$0.00	$595.01
		Energy Star Top-Load.	Horizontal Axis Washer	Incremental	$530.86	$0.00	$0.00	$530.86	$32.09	$179.11	$0.00	$0.00	$211.21
Appliances	Home Office Equipment, Energy Star or better	Std. Home Office Equip.	E-Star Office Equip.	Incremental	$0.00	$0.00	$0.00	$0.00	$0.00	$19.06	$0.00	$0.00	$19.06
Appliances	Refrigerator/Freezer, Removal of Secondary Unit	Use Secondary Unit	Remove Secondary Unit	Full	$0.00	$50.90	$0.00	$50.90	$0.00	$117.70	$0.00	$0.00	$117.70
Appliances	TVs and Home Electronics, Energy Star or better	Std. TV & Home Elec.	E-Star TV, etc.	Incremental	$0.00	$0.00	$0.00	$0.00	$0.00	$10.48	$0.00	$0.00	$10.48
Demand Response	Home Energy Management System w/ Smart T-Stat	No Home EMS	Install Home EMS	Full	$1,061.72	$509.00	$0.00	$1,570.72	$4,423.83	N/A	$0.00	N/A	$4,423.83
Demand Response	Water Heaters, Direct Load Control	No Direct Load Control	Install Direct Load Control	Full	$127.41	$35.63	$0.00	$163.04	$524.86	N/A	$0.00	N/A	$524.86

* Unless noted otherwise, the cost data do not include the cost of system accessories such as ductwork, piping, etc.

Figure 6-7
Sample Economic Screening, Simplified TRC Test (Single Family Home)

After this third level of screening has been conducted, the analyst will have enough information to determine the *economic potential*. The economic potential represents the maximum potential energy savings and/or demand impacts that are economically feasible for a given EE measure, without consideration to customer response. See Chapter 8 for more detail on estimating the economic potential. In some cases, utilities stop here and then leap-frog to Step 6: Program Design (see Figure 6-1). In other cases, utilities proceed to the next level of screening, which takes customer response into account (see Chapter 7).

Summary and Resources

This chapter has described the issues associated with identifying applicable EE measures and performing a three-level screening process to eliminate measures that are not appropriate for a utility's conditions.

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7
SIZING UP CUSTOMER ACCEPTANCE AND RESPONSE

Introduction

Once the EE measures, technologies, or programs have been screened for technical and economic potential, the next step is to determine the *achievable potential*.[43] As discussed in the last chapter, the economic potential represents the maximum energy savings and/or demand impacts that are economically feasible for a given measure, without considering program participation, customer acceptance, or budget constraints. Achievable potential—a subset of economic potential—represents the maximum savings that a utility can expect to achieve given the likely rate of customer acceptance.

[43] In the context of this document, "EE" refers to both energy efficiency/conservation and demand response.

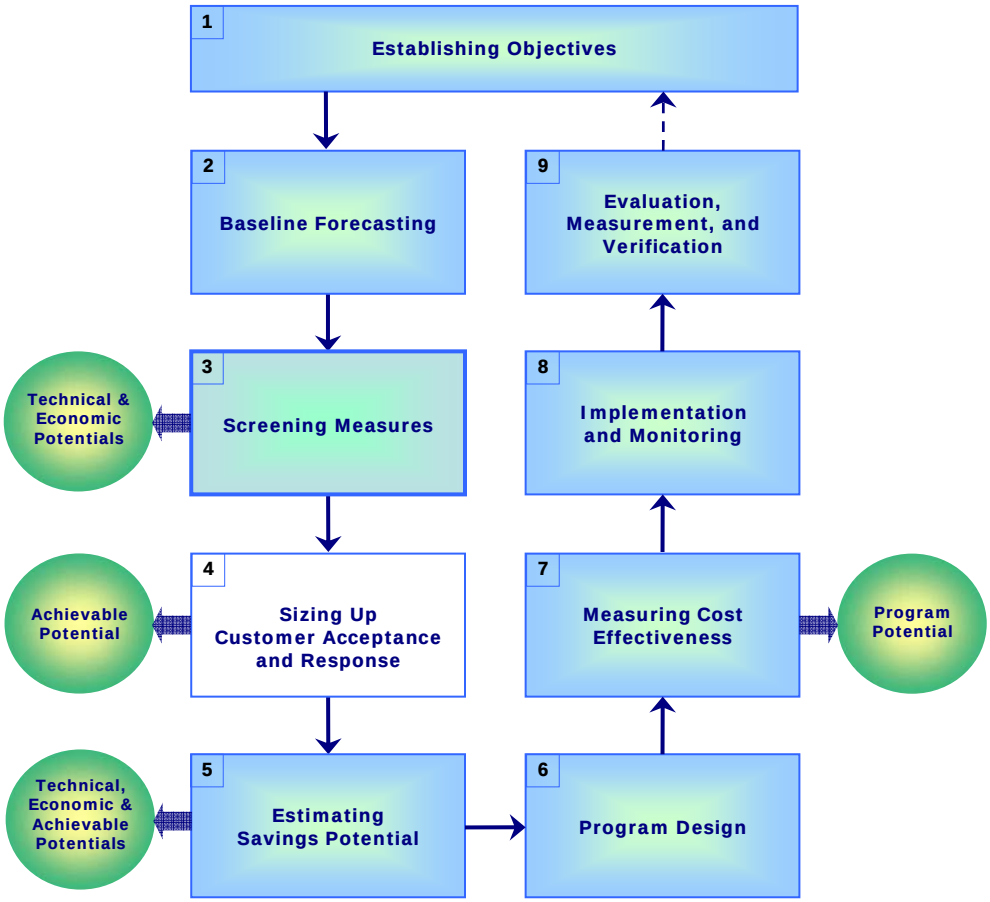


Figure 7-1
EE Program Process, Step 4: Sizing up Customer Acceptance and Response

Figure 7-2 shows the three stages of potential estimation.

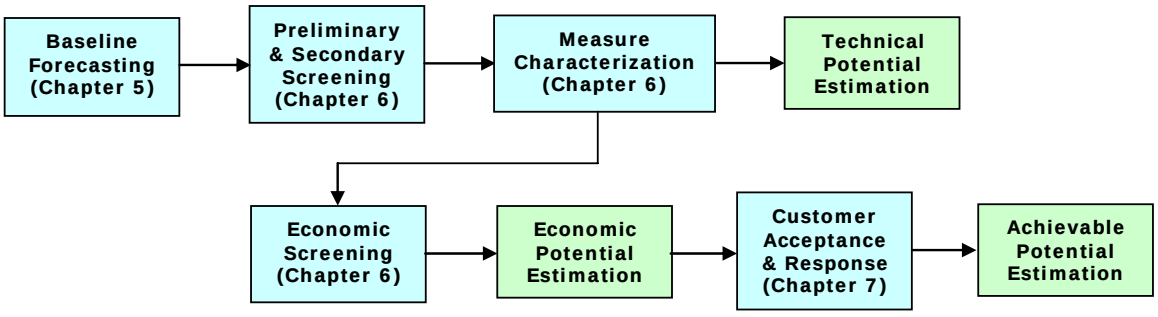


Figure 7-2
Three Stages of Potential Estimation: Technical, Economic, Achievable

In this chapter we discuss the methods for estimating customer acceptance or participation rates. Ultimately, how this question is addressed depends of the type of measure, program, or technology being evaluated. In general,

- For building shell and equipment/technology measures, the question is the proportion of customers that will purchase the measure or the customer acceptance rate.
- For load control or end-use programs, where multiple measures may affect the same end use such as efficient heating technologies, the question is the proportion of customers that will join the program or adopt the efficient end-use.
- For dynamic pricing or demand response programs, the question is the proportion of customers that will adopt the pricing program.[44]

Note that dynamic pricing programs are somewhat different than measures, technologies or load control programs because pricing programs have two distinct customer behavior components rather than just one: (a) how will customers react to the price signal—an input to economic potential discussed in the last chapter, and (b) how many customers are likely to join the program—an input to achievable potential.

Developing Customer Acceptance, Adoption, or Participation Rates

Customer acceptance, adoption, or participation rates can be estimated based on primary data or secondary data. At the market level, the terminology is market acceptance or adoption. At the individual level, each household or premise makes a binary decision whether to adopt the measure, technology, or program. Primary data are typically obtained from surveys of utility customers, pilot programs, or from programs that have already been implemented. Secondary data are typically obtained from other utility pilot or full scale programs, from results published by energy-related organizations such as EPRI or the American Council for an Energy Efficient Economy (ACEEE), or from government databases compiled by the Energy Information Administration in the U.S. Department of Energy.[45]

Primary Data: Survey Methods

For measures or programs that are new to customers or to the utility industry, actual data on customer acceptance may not be available. In these instances, the goal is to estimate a "hypothetical" acceptance or adoption rate that is as accurate as possible. Several different types of survey questions can be used to estimate hypothetical customer acceptance or participation rates. These include:

- Standard likelihood of purchase or likelihood of participation questions where customer responses on a rating scale are converted to the probability of customer participation in a program or the probability of purchasing technology. Examples of likely to purchase/participate questions are the following:

[44] Note that how customers respond to the price signal or the demand response is an input to economic potential
[45] See www.epri.com and www.aceee.org

  - On a rating scale of 1 to 10, how likely are you to purchase technology X in the next year?
  - On a rating scale of 1 to 10, how likely would you be to participate in this pricing program?
  - How likely would you be to purchase technology X if it had a payback of 2 years?
- Contingent valuation surveys where information on customer willingness to pay for a measure or a technology is used to estimate the probability of customer participation in a program. These questions require yes/no responses and take the following form:
  - Would you be willing to pay $X per month to decrease carbon emissions in your area by Y tons?
    - If yes, would you be willing to pay $2X per month to decrease carbon emissions in your area by Y tons?
    - If no, would you be willing to pay 1/2X per month to decrease carbon emissions in your area by Y tons?
- Conjoint or choice-based conjoint surveys ask the customer to tradeoff the attributes of one program against another (or one technology against another). Such surveys pose a series of questions for which the characteristics of a given program vary and the respondent is asked to choose a preferred program attribute set. The responses to these questions can be used to statistically estimate the probability of a customer joining a program. A typical conjoint question might look like the question in Figure 7-3 for a critical peak pricing program. The information gathered from these types of surveys and questions is used in a statistical model to estimate customer acceptance or participation rates.

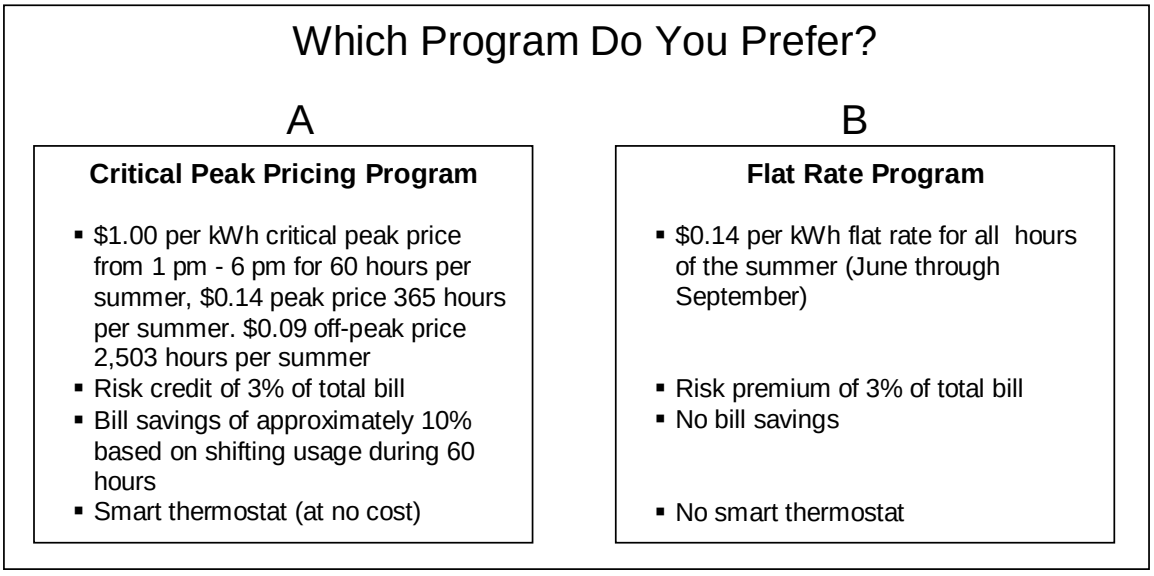


Figure 7-3
Example of a Choice-based Conjoint Question for a Pricing Program

Pilot Programs

Some utilities implement pilot programs to gauge customer acceptance before implementing a full-scale program. When implementing a pilot program, it is critical to use a statistically sound experimental design so that the pilot results can be generalized to the target population. Such pilot programs can be very helpful in both understanding potential participation rates as well as obtaining feedback on program features that appeal or do not appeal to customers. As discussed earlier, pilot programs are very effective for gauging customer response to pricing signals. Designing an effective pilot program to measure customer response was discussed in detail in Chapter 6; that general discussion applies to using pilot programs to measure customer acceptance.

Primary Data: Historical Rates

For some EE measures, programs, and technologies, utility companies may have already gathered historical data on customer acceptance, customer participation, or current saturation levels of measures. In these cases, the issue is how to convert historical acceptance or participation rates into future projections. When a few historical data points are available, the typical way to forecast market penetration of a relatively new technology or program over time is to use a diffusion or S-shaped curve. The most common model is the Bass diffusion model which has a long history in marketing and market forecasting.[46]

$$L(t) = p + q/M\ [N(t)]$$

Where

L(t) = likelihood of customer adoption of program or technology at time t

p = coefficient of innovation (or external influence)

q = coefficient of imitation (or internal influence)

M = market potential (in our case, economic potential) or the total number of customer in the market segment

N(t) = the number of customers that have already adopted the program or technology at time t.

Figure 7-3 shows two examples of S-shaped diffusion curves. The S-shaped curve is used to account for the typical life cycle of a relatively new technology or program. Initially only a few customers adopt the technology or program (i.e., early adopters or innovators), then the technology or program starts to diffuse more rapidly through the potential market as "imitators" start to adopt, finally the market become saturated and the rate of new adoptions flattens out. Figure 7-4 illustrates the truism that new products penetrate the market at different rates.

[46] Gary L. Lilien and Arvind Rangaswamy, "Marketing Engineering: Computer-Assisted Marketing Analysis and Planning." 2nd edition. Prentice Hall. 2003.

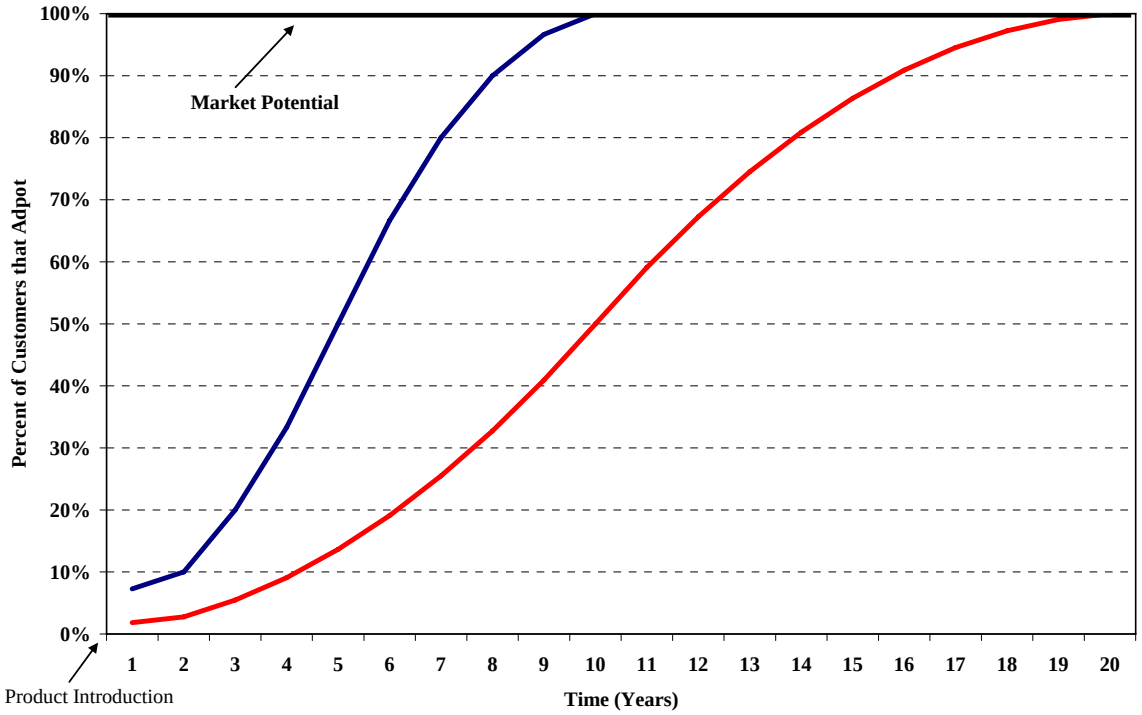


Figure 7-4
Example of Two S-shaped Diffusion Curves for New Product Adoption[47]

Secondary Data

Although primary data are likely to provide the most accurate utility-specific estimates, secondary sources can be very valuable and are often the only source available given time and budget constraints. Useful secondary data sources are the following:

- Data on analogous programs or technologies (from your company or from other utilities) may be useful in estimating customer acceptance for a new program or technology.
- Data from government sources (e.g., DOE), trade associations, or non-profit organizations (e.g., ACEEE) on historical growth rates for the penetration of efficient technologies or end uses may be useful in estimating customer adoptions of new technologies.

Once estimated, customer acceptance or participation rates are applied to the economic potential estimates to arrive at achievable potential.

[47] The product represented by the steeper curve penetrates the market at a faster rate

Summary

This chapter has described methods for estimating customer acceptance or participation rates prior to program implementation. These include primary data based on surveys (likelihood of purchase, contingent valuation, and choice-based conjoint surveys), pilot programs, or historical rates and secondary data sources. As discussed, estimates of customer acceptance are the link between economic potential and achievable potential.

8
ESTIMATING SAVINGS POTENTIAL

Introduction

The next step in the EE program process is to estimate the savings potential of the EE measures, as illustrated in Figure 8-1.[48]

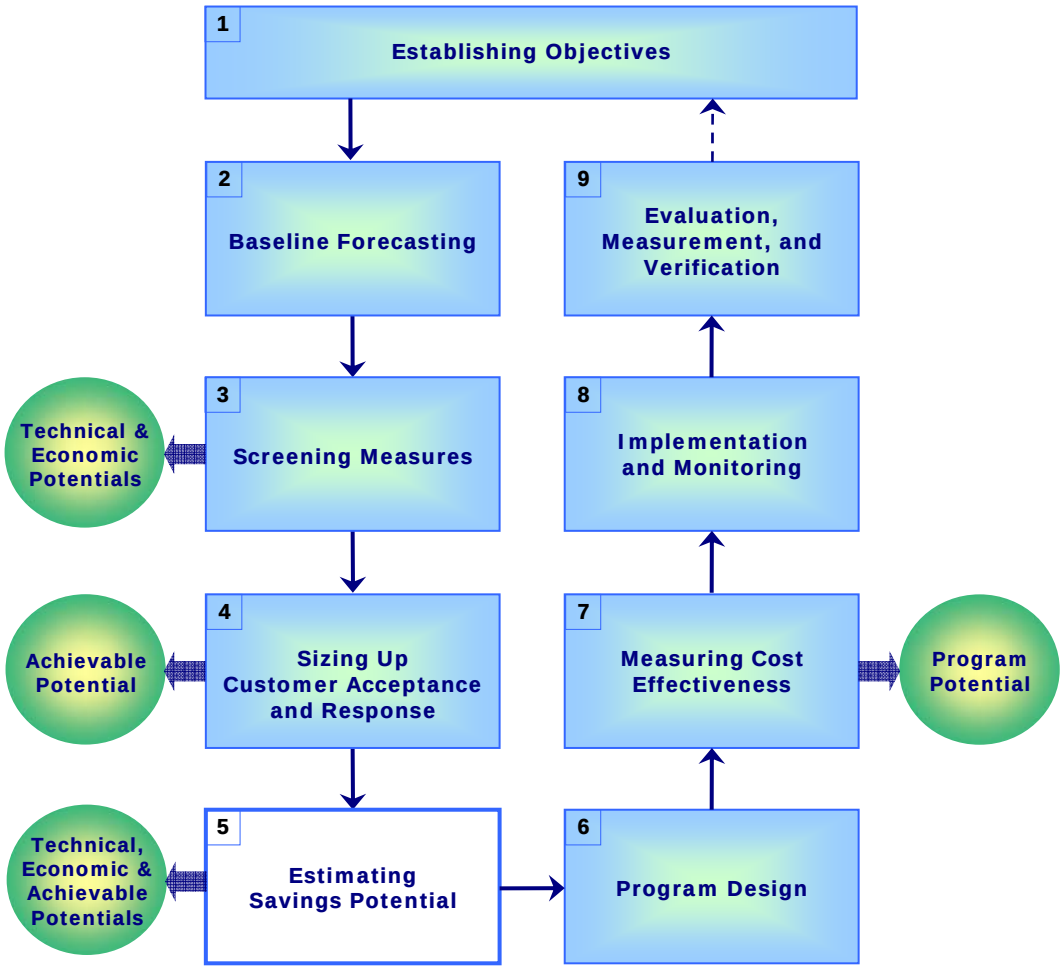


Figure 8-1
EE Program Process, Step 5: Estimating Savings Potential

[48] In the context of this document, "EE" refers to both energy efficiency/conservation and demand response.

This chapter describes how to quantify the savings potential of a group of measures that have been identified as being applicable to your service territory. The savings potential due to energy efficiency measures and demand response measures are addressed separately.

The Three Levels of Savings Potential

In the context of a program design and planning process, the savings potential of a group of EE measures that are applicable to a utility's service territory can be quantified at three different levels: (1) the technical potential, (2) the economic potential, and (3) the achievable potential. Each of these levels are defined and discussed below.

Technical Potential represents the savings due to EE measures that would result if all of the most efficient measures are adopted by your customers, regardless of cost. It provides the broadest and highest definition of savings potential since it quantifies the savings that would result if all current equipment, processes, and practices in all sectors of the market were replaced by the most efficient measures that pass the first two levels of screening that were discussed in Chapter 6 (the preliminary and secondary screens). Technical potential does not take into account the cost-effectiveness of the measures.

There are two types of technical potential, each with its own term and meaning. "Instantaneous technical potential" assumes that all of the current stock of equipment is immediately changed out by the most efficient measures available regardless of service life considerations (i.e. retrofit). "Phase-in technical potential" assumes that only the portion of the current stock of equipment that has reached the end of its useful life and is due for turnover is changed out by the most efficient measures available (i.e. replacement). As such, the phase-in technical potential will be lower than the corresponding instantaneous technical potential during the first several years since it assumes that the replacements occur gradually over time. Instantaneous technical potential ignores a genuine limitation that arises during the implementation of energy-efficiency programs since certain measures (e.g. upgrades from SEER 13 to SEER 15 air conditioners) are best targeted to customers already in the market for new or replacement equipment.

Economic Potential represents the savings due to EE measures that would result if only cost-effective measures are adopted by the utility's customers. It is a subset of the technical potential and is quantified only over those measures that pass the economic screen that was discussed in Chapter 6. Similarly to technical potential, the term "instantaneous economic potential" assumes that all of the current stock of equipment is changed out immediately by the most cost-effective measures regardless of service life considerations (i.e. retrofit). "Phase-in economic potential assumes that only the portion of the current stock of equipment that has reached the end of its useful life and is due for turnover is changed out by the most cost-effective measures (i.e. replacement). Since many measures pass the economic screen only when they are implemented at the end of the equipment life cycle (and thus incremental costs are considered instead of full costs), the phase-in economic potential is usually evaluated instead of the instantaneous economic potential.[49] Program administration costs and customer preferences are entirely ignored in the economic potential analysis.

[49] Incremental costs are usually used to evaluate the cost-effectiveness of measures in replacement situations (e.g. the equipment has reached the end of its useful life and needs to be replaced) or new construction situations (e.g. there is

Achievable potential is a subset of the economic potential. Achievable potential refines the economic potential by taking into account expected program participation, customer preferences, and budget constraints (these and other customer-related factors are discussed in Chapter 7). Achievable potential establishes a maximum target for the savings that a utility can hope to achieve through its programs. As such, this savings potential is often referred to as the *maximum achievable potential (MAP)*. Achievable potential usually involves incentives that represent 100% of the incremental cost of energy efficient measures above baseline measures, combined with high administrative and marketing costs. Therefore, achievable potential must be balanced against other goals such as maintaining low electric rates and customer equity in the development of final program designs and savings targets.

Figure 8-2 illustrates the different levels of savings potential.

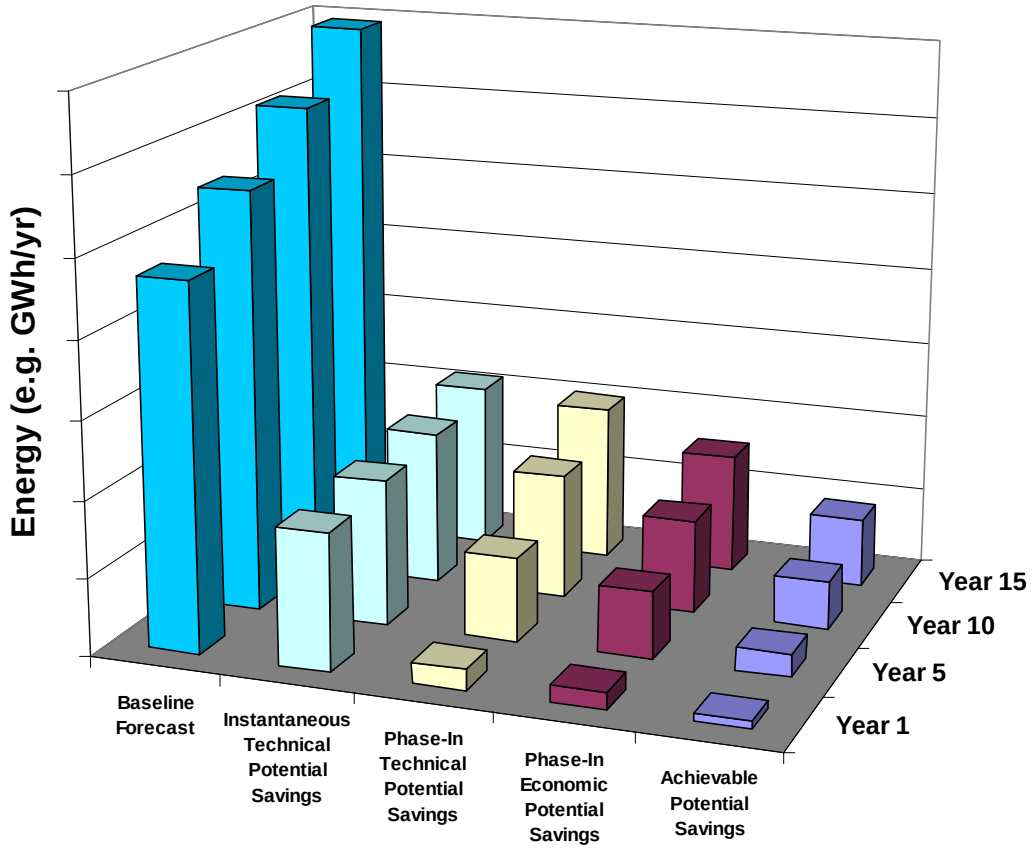


Figure 8-2
The Different Levels of Savings Potentials

Figure 8-3 illustrates the relationship between the levels of savings potential and the screening process described in Chapter 6.

a choice of two or more design alternatives). Full costs are usually used to evaluate the cost-effectiveness of measures in retrofit situations (e.g. the equipment is replaced before the end of its useful life) or when the measure is a new addition to existing equipment (e.g. water heating timer, window film, etc.).

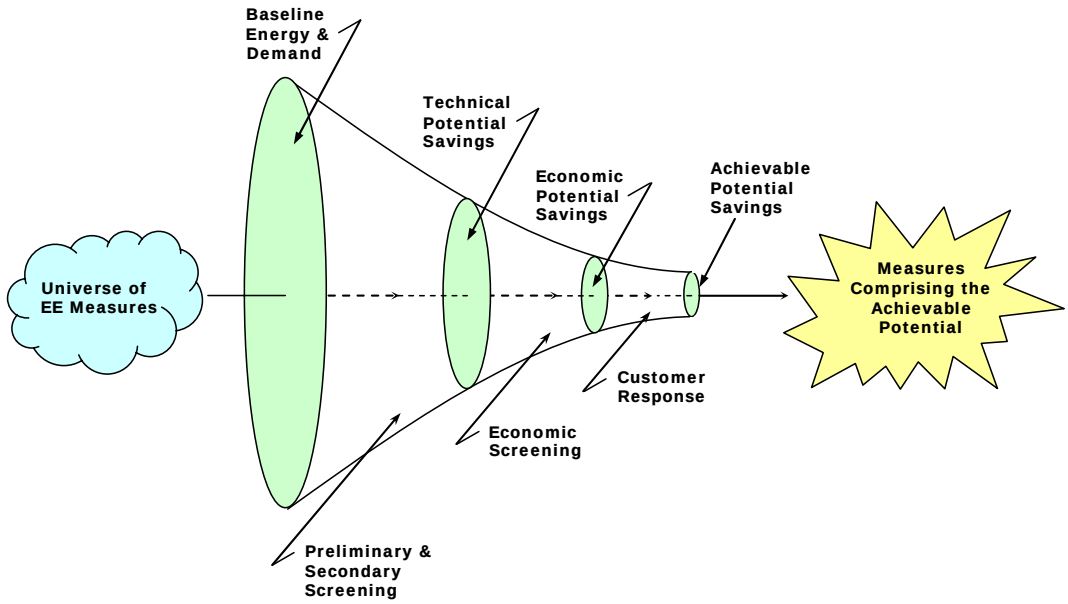


Figure 8-3
Relationship of Potential Savings to Screening Process

Estimating Savings Potential—Energy Efficiency Measures

In the context of this section's discussion, "savings potential" refers to the collective impact of a group of measures (rather than individual measures) applicable to a utility's service territory, which is more relevant to program design and planning. This section discusses the steps involved in estimating the technical, economic, and achievable potential for a group of energy efficiency measures. The entire process is illustrated in Figure 8-4. Note that several elements of this process have already been discussed in the previous chapters.

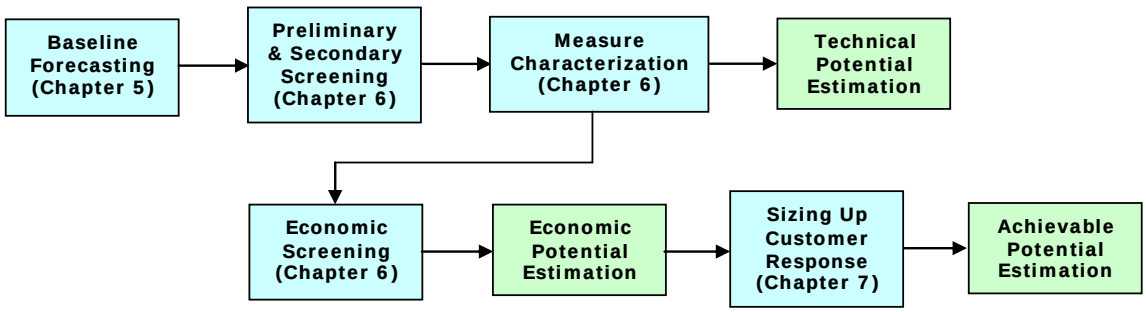


Figure 8-4
Process of Savings Potential Estimation

Technical Potential

The technical potential can be represented as:

*Technical Potential of Energy Savings = (Energy Baseline Forecast) * (Savings)*

*Technical Potential of Peak Demand Reduction = (Demand Baseline Forecast) * (Reduction)*

It can be seen from the above expressions that the process of estimating the technical potential of a group of measures is driven by the level of detail developed in the baseline forecast (see Figure 5-2). For "bottom-up" approaches, it is likely that the baseline forecast is available at the equipment or technology level. However, for "top-down" approaches, the baseline forecast is usually available only at the end-use level. As such, the challenge is to determine the savings at the appropriate level of detail that can be applied to the previously developed baseline forecast.

The following outlines a general procedure for estimating the technical potential:

Develop base case unit energy consumption (UEC) and demand matrices at the highest level of detail that is available from the baseline forecast.

- For bottom-up approaches, this usually entails developing representative values of the base case energy consumption and demand of each type of equipment or technology at the per-unit level (e.g. kWh/yr and demand of a base case central air conditioner). An example of UECs and demand at the per-unit level is shown in Table 8-1. These values can be developed by using resources such as computer modeling (e.g. DOE-2, Energy+, eQuest, etc.), engineering calculations, primary data from the utility's databases, and secondary data from key industry sources (e.g. appliance manufacturers) and other utilities.
- For top-down approaches, the most common practice is to develop representative values of the base case energy consumption and demand for each end-use (e.g. cooling kWh/yr and demand of a base case office building). An example of UECs and demand at the end-use level is shown in Table 8-2. The development of these values is most conducive to computer modeling (e.g. DOE-2, Energy+, eQuest, etc.) and engineering calculations since utilities do not usually track their customers' energy consumption and demand at the end-use level.

Develop efficiency-case unit energy consumption (UEC) and demand matrices at the highest level of detail that is available from the baseline forecast. The format of the UECs and demand matrices for the efficiency case is the same as that of the baseline described in Step 1 above. The difference is that the values are representative of what the energy consumption and demand would be if all of the measures that pass the primary and secondary screens (see Chapter 6) are implemented.

- For bottom-up approaches, it is possible to use the information developed in the measure characterization (Chapter 6) for all of the most energy-efficient measures that pass the primary and secondary screens to develop the efficiency-case UECs and demand at the equipment or technology level.

- Top-down approaches involve UEC and demand development at the end-use level. It is not difficult to imagine that, of the group of measures that pass the primary and secondary screens, multiple measures have the potential to affect the same end use(s). Also, measures that affect the same end use(s) may be mutually exclusive (e.g. it is not possible to implement the high-efficiency water heater and the heat pump water heater measures at the same time). As such, it is necessary to create "bundles" of measures that capture the potential impacts of all measures within the same category. An example of the bundles of measures that could be developed for the commercial sector is shown in Table 8-3. Computer modeling and engineering calculations, which take into account the impacts due to each bundle of measures, are usually used to derive the values of the efficiency-case UECs and demand at the end-use level.

The difference between the base case UEC/demand and the efficiency-case UEC/demand is the technical potential savings. It is now possible to calculate a savings for each equipment, technology, or end use, and apply these savings to the baseline forecast to obtain the technical potential.

- For bottom-up approaches, the savings calculated for each type of equipment or technology can be extrapolated to the segment and sector levels by using the previously developed baseline forecasting model (in general, the sum of all of the individual technical potentials at the equipment or technology level is equal to the total technical potential). This method can be used to obtain the instantaneous technical potential over the time horizon of the study. Alternatively, the baseline forecasting model can be designed to take into account the effects of equipment replacement timing (e.g. at the end of the life cycle) and new constructions to obtain the phase-in technical potential.
- Top-down approaches usually require the savings calculated for each end-use to be expressed as percentages. These percent savings can be applied to the end-use level data in the baseline forecasting model to obtain the instantaneous technical potential. As with the bottom-up approach, the baseline forecasting model can be designed to take into account the effects of equipment replacement timing (e.g. at the end of the life cycle) and new constructions to obtain the phase-in technical potential.

Economic Potential

As illustrated in Figure 8-4, the process of estimating economic potential is completely independent of technical potential. Since the road to the achievable potential runs through the economic potential (and not the technical potential), many program planners and analysts completely bypass the technical potential and proceed directly to the economic potential.

The process for estimating the economic potential is almost identical to that used for the technical potential. The main difference is that the group of measures used in the analysis passes an economic screen. In other words, the economic potential is only comprised of cost-effective measures, whereas the technical potential is comprised of the most energy-efficient measures regardless of cost considerations.

The economic potential can be represented as:

*Economic Potential of Energy Savings = (Energy Baseline Forecast) * (Savings)*

*Economic Potential of Peak Demand Reduction = (Demand Baseline Forecast) * (Reduction)*

As evident from these expressions, the process of estimating the economic potential of a group of measures is driven by the level of detail developed in the baseline forecast (see Figure 5-2). For "bottom-up" approaches, it is likely that the baseline forecast is available at the equipment or technology level. However, for "top-down" approaches, the baseline forecast is usually available only at the end-use level. As such, the challenge is to determine the savings at the appropriate level of detail that can be applied to the previously developed baseline forecast.

The following outlines a general procedure for estimating the economic potential:

1. Develop base case unit energy consumption (UEC) and demand matrices at the highest level of detail that is available from the baseline forecast.
   - For bottom-up approaches, this usually entails developing representative values of the base case energy consumption and demand of each type of equipment or technology at the per-unit level (e.g. kWh/yr and demand of a base case central air conditioner). An example of UECs and demand at the per-unit level is shown in Table 8-1. These values can be developed by using resources such as computer modeling (e.g. DOE-2, Energy+, eQuest, etc.), engineering calculations, primary data from the utility's databases, and secondary data from key industry sources (e.g. appliance manufacturers) and other utilities.
   - For top-down approaches, the most common practice is to develop representative values of the base case energy consumption and demand for each end-use (e.g. cooling kWh/yr and demand of a base case office building). An example of UECs and demand at the end-use level is shown in Table 8-2. The development of these values is most conducive to computer modeling (e.g. DOE-2, Energy+, eQuest, etc.) and engineering calculations since utilities do not usually track their customers' energy consumption and demand at the end-use level.

Table 8-1
Example of UECs and Demand at the Per-Unit Level

Unit Energy Consumption and Peak Demand		Single Family House
Basic Appliances		**UEC (kWh/yr)**
	Refrigerator 1	961
	Freezer	1,025
	Water Heater	2,719
	Dishwasher--motor/heater	179
	Clothes washer--motor	103
	Clothes Dryer	839
	Range/Oven	822
	Refrigerator 2	1,144
	Lighting	1,719
Weather Sensitive End Uses		**UEC (kWh/yr)**
	Room AC	1,806
	Central AC	6,325
	Electric Heat	0
Basic Appliances		**Peak kW**
	Refrigerator 1	0.20
	Freezer	0.22
	Water Heater	0.41
	Dishwasher--motor/heater	0.03
	Clothes washer--motor	0.04
	Clothes Dryer	0.10
	Range/Oven	0.10
	Refrigerator 2	0.24
	Lighting	0.30
Weather Sensitive End Uses		**Peak kW**
	Room AC	0.555
	Central AC	2.474
	Electric Heat	0.000

Table 8-2
Example of UECs and Demand at the End-Use Level

	Energy (kWh/yr)	
	Large Office	
End Use	**Existing**	**New**
Heating	661,328	84,822
Cooling	2,767,448	1,918,069
Ventilation	1,162,030	653,439
Water Heating	85,305	83,564
Refrigeration	0	0
Lighting	1,920,417	1,408,312
Miscellaneous	2,363,237	2,269,991
Total	8,959,764	6,418,198
	Demand (kW)	
	Large Office	
End Use	**Existing**	**New**
Heating	39.8	41.2
Cooling	265.3	215.0
Ventilation	123.1	67.3
Water Heating	11.4	11.2
Refrigeration	0.0	0.0
Lighting	321.8	236.0
Miscellaneous	205.0	195.2
Total	966.4	766.0

Develop efficiency-case unit energy consumption (UEC) and demand matrices at the highest level of detail that is available from the baseline forecast. The format of the UECs and demand matrices for the efficiency case is the same as that of the baseline described in Step 1 above. The difference is that the values are representative of what the energy consumption and demand would be if all of the measures that pass the economic screen (see Chapter 6) are implemented.

- For bottom-up approaches, it is possible to use the information developed in the measure characterization (Chapter 6) for all of the cost-effective measures that pass the economic screen to develop the efficiency-case UECs and demand at the equipment or technology level.
- Top-down approaches involve UEC and demand development at the end-use level. It is not difficult to imagine that, of the group of measures that pass the economic screen, multiple measures have the potential to affect the same end use(s). Also, measures that affect the same end use(s) may be mutually exclusive (e.g. it is not possible to implement the high-efficiency water heater and the heat pump water heater measures at the same time). As such, it is necessary to create "bundles" of measures that capture the potential impacts of all measures within the same category. An example of the bundles of measures that could be developed for the commercial sector is shown in Table 8-3. Computer modeling and engineering calculations, which take into account the impacts due to each bundle of measures, are usually used to derive the values of the efficiency-case UECs and demand at the end-use level.

Table 8-3
Example of Measure Bundles

Bundle Category	Description
Cooling	This bundle consists of replacing the baseline cooling equipment with one that represents the high efficiency level/technology available on the market. The high efficiency level is EER 11 for packaged air-conditioners and EER 11.5 for room air-conditioners. For chillers, the high efficiency level is 1.11 for air-cooled reciprocating chillers, 1.10 for air-cooled screw chillers, 0.85 for water-cooled reciprocating chillers, 0.66 for water-cooled screw chillers, and 0.50 for water-cooled centrifugal chillers.
Plug Load	This bundle consists of replacing all baseline office equipment with high efficiency/technology equipment available on the market. The measure also includes guestroom occupancy sensors and high-efficiency vending machines in the relevant building types. This generally results in a 20% reduction in the various plug load densities.
Building Shell	This bundle consists of replacing all baseline building shell measures with high efficiency/technology measures available on the market. Specifically, this is installing wall insulation R-19, ceiling insulation of R-25, and Energy Star Windows (only in small offices, restaurants, grocery stores and schools).
Lighting	In each of the commercial building types, this bundle consists of replacing the entire stock of fluorescent tube lamps with T-8 lamps with electronic ballasts, replacing of the entire stock of incandescent lamps with compact fluorescent lamps, and using LED exit signs, occupancy sensors and task lighting. In existing buildings only, this bundle also entails de-lamping and installing reflectors. This generally results in a 25% reduction in the various lighting densities in old vintage buildings and 10% reduction in the various lighting densities in the new vintage buildings.
Refrigeration	This bundle consists of replacing all of the baseline refrigeration equipment with high efficiency/technology equipment available on the market. The bundle includes: high efficiency compressors, anti-sweat heaters, and floating head pressure controls. With the exception of the anti-sweat heater, which is modeled directly, these measures are simulated by increasing the compressor efficiency by 15%.
Water Heating	This bundle consists of replacing all baseline water heating equipment with high efficiency/technology equipment available on the market. The equipment used is high-efficiency electric water heater with an EF of 0.98 in small offices and restaurants.

The difference between the base case UEC/demand and the efficiency-case UEC/demand is the economic potential savings. It is now possible to calculate a savings for each equipment, technology, or end use, and apply these savings to the baseline forecast to obtain the economic potential.

- For bottom-up approaches, the savings calculated for each type of equipment or technology can be extrapolated to the segment and sector levels by using the previously developed baseline forecasting model (in general, the sum of all of the individual economic potentials at the equipment or technology level is equal to the total economic potential). This method can be used to obtain the instantaneous economic potential over the time horizon of the study. Alternatively, the baseline forecasting model can be designed to take into account the effects of equipment replacement timing (e.g. at the end of the life cycle) and new constructions to obtain the phase-in economic potential.
- Top-down approaches usually require the savings calculated for each end-use to be expressed as percentages. These percent savings can be applied to the end-use level data in the baseline forecasting model to obtain the instantaneous economic potential. As with the bottom-up approach, the baseline forecasting model can be designed to take into account the effects of equipment replacement timing (e.g. at the end of the life cycle) and new constructions to obtain the phase-in economic potential.

Achievable Potential

As illustrated in Figure 8-4, the achievable potential can be estimated after the economic potential has been determined and the customer acceptance has been analyzed (see Chapter 7). The achievable potential can be represented as:

*Achievable Energy Savings Potential = (Economic Potential) * (Customer Acceptance)*

*Achievable Peak Demand Reduction Potential = (Economic Potential) * (Customer Acceptance)*

It can be seen from the above relationship that the key to estimating the achievable potential lies in the quantification of the customer acceptance. There are several ways to accomplish this, but a commonly used method involves the concept of “market acceptance ratios” (MARs).

MARs are mathematical adjustment factors that are applied to the economic potential results in order to account for customer acceptance issues such as program participation, customer preferences, etc. The MARs may also account for programmatic considerations such as availability and amount of incentives offered by the utility, marketing costs, administrative costs, etc. MARs can be developed using the information obtained from the analysis of the customer response (see Chapter 7). Alternatively, the MARs can be developed through a qualitative assessment of secondary sources such as industry studies and general knowledge of energy efficiency efforts demonstrated from around the country.

The dynamics of MARs generally differ by market segment (e.g. replacement equipment in existing housing stock, as opposed to new construction), end use, and type of equipment. Also, MARs generally increase over time to reflect the fact that market penetration of energy-efficiency measures usually increases over time as a result of the utility's marketing efforts and/or market transformation. Table 8-4 provides an example of MARs that were developed for the commercial sector in an actual energy-efficiency potential study.

Table 8-4
Example of Market Acceptance Ratios

End Use	Year 1	Year 5
Heating	15%	30%
Cooling	15%	30%
Ventilation	25%	40%
Water Heating	15%	30%
Refrigeration	25%	45%
Lighting	25%	40%
Miscellaneous	10%	25%

The following is an outline of the general procedure for estimating the achievable potential:

1. *Develop adjustment factors (e.g. market acceptance ratios) that account for customer acceptance issues.* These adjustment factors can be developed using the information obtained from the analysis of the customer response (see Chapter 7).
   - For bottom-up approaches, the adjustment factors are usually developed at the equipment or technology level
   - For top-down approaches, the adjustment factors are usually developed at the end-use level

Apply the adjustment factors to the economic potential over the study time horizon to obtain the achievable potential. The phase-in economic potential is most commonly used for the quantification of the achievable potential because it provides a more realistic depiction of customers' behavior (e.g. customers are more likely to wait until the end of the life cycle of expensive equipment such as chillers, central air conditioners, etc. before replacing them with energy-efficient units).

Estimating Savings Potential—Demand Response Measures

As discussed in Chapter 6, for the residential sector, the demand response measures include innovative rate options such as time of use (TOU) rates, critical peak pricing (CPP) rates, and real time pricing (RTP), as well as direct load control programs and the associated enabling equipment or technologies such as smart meters, smart thermostats, always-on gateway systems, air-conditioning switches, and advanced notification mechanisms (see Figure 6-2).[50] Throughout this section, we focus on the residential sector.

Figure 8-5 shows a range of flexible rate options. As rates move from the traditional flat rates to more flexible rate options such as TOU, CPP, and RTP, risk is transferred from the supplier to the consumer. This transfer of risk is what induces a customer to respond by changing her behavior and shifting her energy usage. Flexible rates promote economic efficiency in the consumption of electricity and result in potential savings. Estimating this potential savings is the focus of this section.

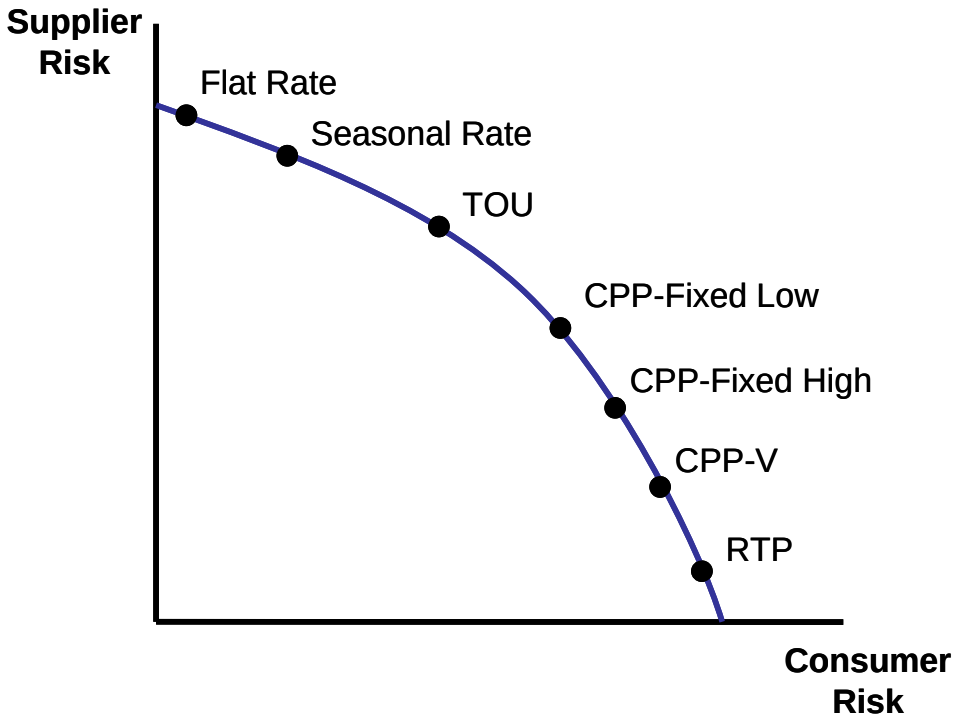


Figure 8-5
Continuum of Rate Option Flexibility and Risk Transfer

[50] Always-on gateway systems adjust the usage of multiple appliances whereas smart thermostats raise the temperature setting on the thermostat by two or four degrees when the price becomes critical.

This section examines how to estimate the savings that can be achieved through demand response measures. The critical question for demand response programs is how customers will adjust their electricity usage in response to the price signal. The customer's "demand response" or price elasticity will determine how much energy the customer shifts and the resulting savings in peak demand reduction. Shifting energy in response to a dynamic price signal during a peak period has two results: peak load reduction by the customer and avoided capacity and energy costs for the utility. Figure 8-6 shows an example of hour-by-hour reduction in peak demand resulting from demand response based on the California Statewide Pricing Pilot (SPP).[51]

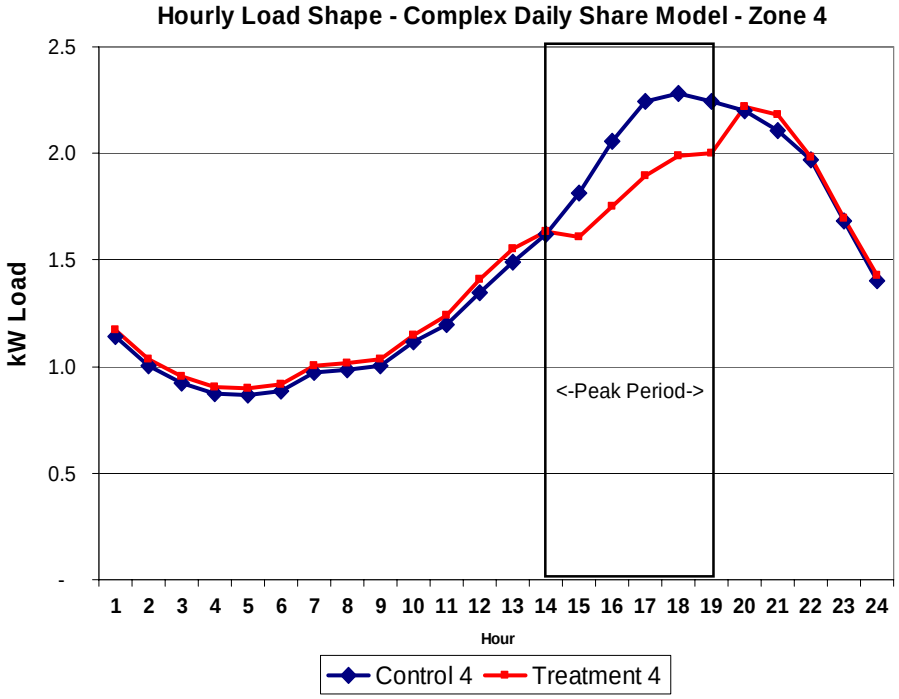


Figure 8-6
Example of Hourly Load Reduction from DR Under a Critical Peak Price

It is important to note that the type of rate, the magnitude of the rate, the enabling technology, and whether the customer has central air conditioning will influence the degree of demand response and the potential savings. Based on the California SPP, customers with central air conditioners were more price responsive than other types of customers, and those with both a central air conditioner and an enabling technology were the most price-responsive. Figure 8-7 shows peak demand reduction by customer type as a function of critical peak prices based on the California SPP.

[51] Charles River Associates, "Impact Evaluation of the California Statewide Pricing Pilot." Final Report, March 16, 2005

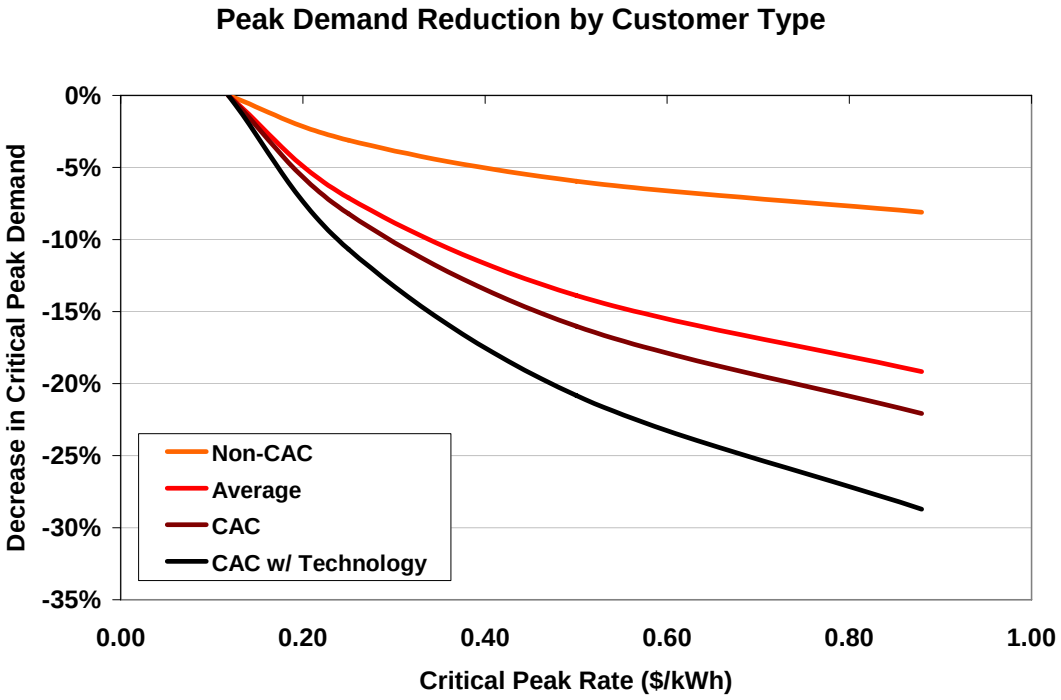


Figure 8-7
Peak Demand Reduction by Customer Type for Range of Critical Peak Prices

The technical, economic, and achievable potentials for peak demand reduction due to demand response measures are discussed below.

Technical Potential

The technical potential for peak demand reduction can be defined as the percent reduction in dispatchable load if all residential customers used the best available DR enabling technology. Based on the California SPP, for residential customers this is the always-on gateway system which has the potential to reduce peak demand by 43%.[52]

The promulgation of advanced metering infrastructure (AMI) and *Smart Grid* technology can facilitate the promulgation of such DR-enabling technology, as discussed in Chapters 13 and 14.

[52] A. Faruqui, R. Hledik, S. Newall, J. Pfeifenberger, "The Power of Five Percent." Discussion Paper. The Brattle Group. May 2007. These estimates for other enabling technologies based on the California CPP are about 13% for smart meters and about 27% for smart thermostats.

Economic Potential

The economic potential for demand response is defined as what would happen if the residential customer class adopted a combination of enabling technologies—a distribution of some customers using best available technology, a portion using some enabling technology, and some using no enabling technology. Recall that economic potential assumes that all customers accept dynamic pricing. The economic potential is the weighted average of each customer group's demand response. One could assume as one example, that 10% of residential customers choose the gateway system with a load reduction impact of 43%; 20% choose the smart thermostat with a load reduction impact of 27%; and 70% choose no enabling technology with a load reduction of impact of 13%).[53] This results in a demand reduction of 18.8% for the residential customer class.

Table 8-5
Example of Economic Potential Derivation

Technology Type	Share of Residential Customers	Load Reduction Impact	Weighted Impact
Gateway System	10%	43%	4.3%
Smart Thermostat	20%	27%	5.4%
No Technology	70%	13%	9.1%
TOTAL			**18.8%**

A utility can draw upon the results of pilot studies of the experience of other utilities to posit assumptions on the distribution of enabling technology among its customers to develop an economic potential for demand response.

Achievable (or Market) Potential

The achievable or market potential is defined as the economic potential multiplied by the customer acceptance rate. The customer acceptance rate will depend on how the program is designed and delivered to customers. Assuming that 20% of the residential class accepts dynamic pricing, which could occur under an optional dynamic pricing program, the resulting market potential is 3.8% (i.e., 20% multiplied by 18.8%). Assuming that 80% of the residential class accepts dynamic pricing, which could occur under a default dynamic pricing program where customers are given the option to opt-out, the market potential is about 15% (i.e., 80% multiplied by 18.8%). Judgment, informed by prior utility experience with DR programs and other insights into customer characteristics, must inevitably be applied to develop an achievable potential for DR.

Ultimately, the amount of demand response that can be delivered as a result of dynamic pricing will depend to a large extent on how the program is designed and delivered to customers.

[53] A. Faruqui, R. Hledik, S. Newall, J. Pfeifenberger, "The Power of Five Percent." Discussion Paper. The Brattle Group. May 2007. See Table 2. Demand Response by Sector and Technology.

How Much Demand Response is There at RTOs and What are the Results?

ISO-New England (ISO-NE), New York ISO (NYISO), PJM, and ERCOT are the current leaders in RTO demand response. ISO-NE has about 1,600 MW enrolled in its programs with around 1,500 MW in emergency programs and 100 MW in economic programs. NYISO has about 2,200 MW enrolled in its demand response programs with around 1,800 MW in emergency programs and approximately 400 MW in economic programs. By contrast to those two RTOs, PJM has a more balanced split amongst program types. It has a total of roughly 5,100 MW in its demand response programs with around 2,100 in emergency programs and 2,900 in economic programs. ERCOT is at the other extreme from ISO-NE and NYISO with basically all of its current demand response participation of 1,800 MW in economic programs. The large industrial base in ERCOT has facilitated demand response participation and in recent times has resulted in oversubscription in its programs. As a result, ERCOT's approach has been to consider that capacity market participation by demand response is not necessary. Other RTOs currently have limited or no participation in their formal demand response programs.[54]

Enrollment in programs, of course, differs from actual impacts. In 2006, NYISO had the largest peak reductions from demand response at 2.8% of peak load or 948 MW. This was followed by ISO-NE with 2.1% peak reduction or 597 MW, and PJM with 1.4% peak reduction or 2,050 MW. Because ERCOT's demand response programs are almost exclusively economic, there was no reduction on peak, but its programs achieved an impressive 4,637 GWh of reduced electricity consumption in 2005.[55]

It is important to understand that inside RTO operating territories there may be substantial amounts of demand response that do not participate in RTO programs. For instance, Midwest ISO (MISO) reportedly has approximately 8,600 MW of DR programs run by utilities that are outside MISO and reportedly achieved a 2.3% reduction at peak in 2006 with these non-RTO programs. Likewise, the California ISO (CAISO) has small demand response programs with enrollment of a couple of hundred MW, but achieved peak reduction of 4.1% or 2,066 MW in 2006 through utility-administered DR programs. Even PJM, with a substantial demand response program portfolio of 5,100 MW, has about 3,200 MW in demand response available in its territory through utility and other non-PJM programs.[56]

Summary and Resources

This chapter has described how to estimate technical, economic, and achievable savings potential—both energy savings and peak demand savings—due to energy efficiency measures and demand response measures.

[54] FERC 2006 Assessment of Demand Response and Advanced Metering; FERC 2007 Assessment of Demand Response and Advanced Metering.
[55] Ibid.
[56] Ibid.

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9
PROGRAM DESIGN

Introduction

The next step in the EE program process illustrated in Figure 9-1 is to design effective programs that will deliver the achievable potential for energy savings and demand reduction discussed in Chapter 8. [57] This chapter is a practical guide to program design.

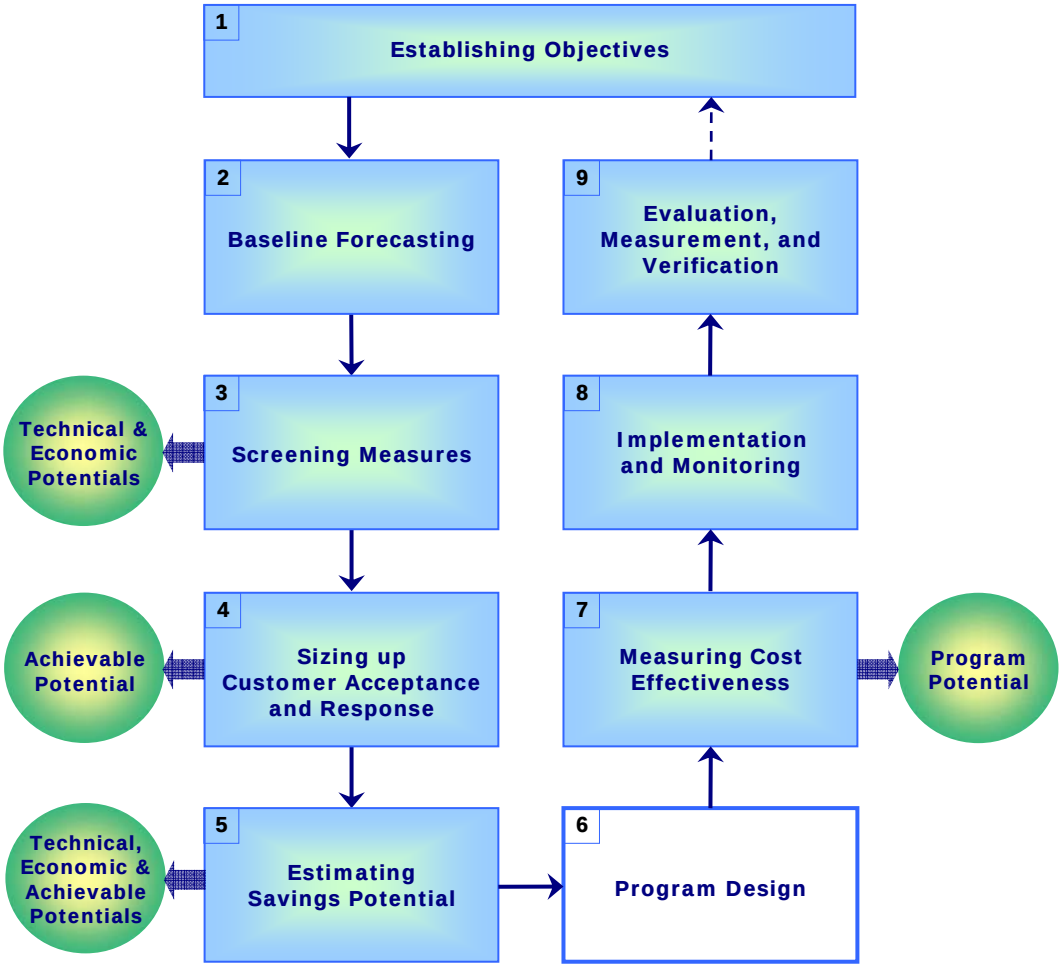


Figure 9-1
EE Program Process, Step 6: Program Design

[57] In the context of this document, "EE" refers to both energy efficiency/conservation and demand response.

Effective EE program design is based on a solid understanding of both customers and markets.[58] By addressing customer needs and overcoming market barriers, a well-designed EE program can:

- *Attain Desired Load Shape Impacts*: Peak clipping, for example, requires targeting the right program options at specific end uses and targeting customers with the greatest coincident load reduction opportunities. Strategic conservation, on the other hand, can be achieved through a wider range of options pertaining to a more diffuse mix of end uses and customers.
- *Ensure Program Cost-Effectiveness*: Poor design can lead to low participation, excess administrative costs, below-target load impacts, or high free readership. Under incentive regulation structures, an EE program that does not meet planning assumptions for cost-effectiveness can adversely affect utility finances.
- *Strengthen Customer Relations*: Each program represents an opportunity to strengthen customer relations and to better understand how customers think and how markets work. This knowledge, accumulated over a series of programs, can be a valuable asset in improving customer relationships and enhancing the utility's long-term competitiveness.

The process of designing an effective EE program involves four main steps: (1) identify target markets and customer needs; (2) design program features to meet customer and utility needs; (3) develop marketing strategies and methods, and (4) develop indicators of program impacts. Figure 9-2 illustrates these program design steps and how they relate to the larger EE program process.

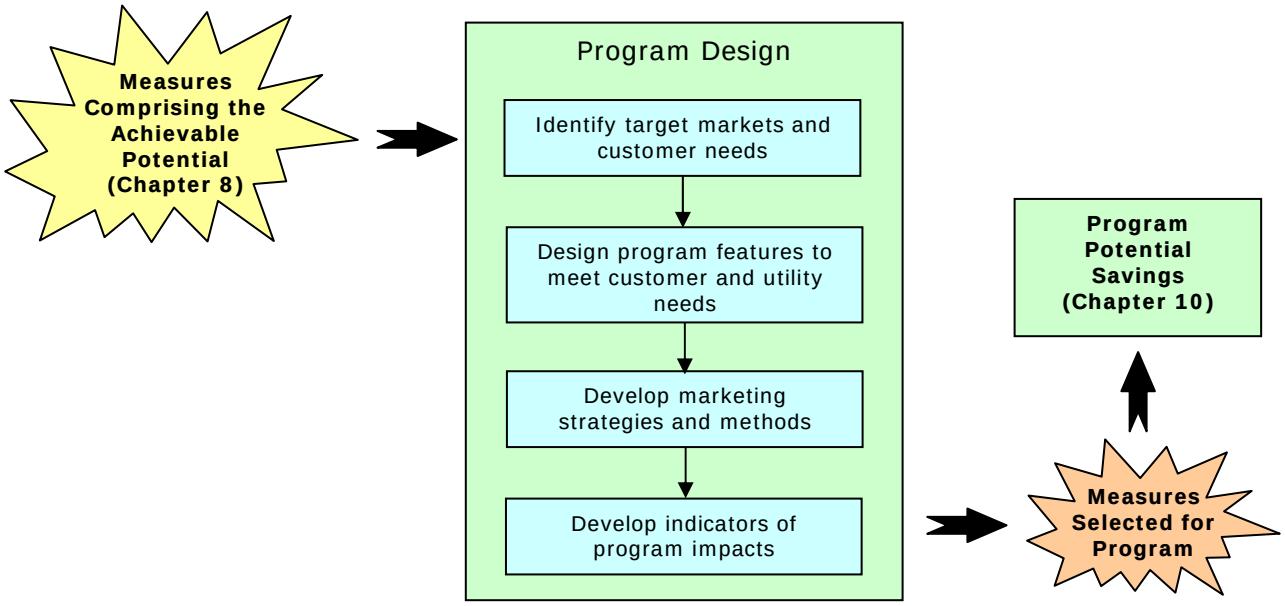


Figure 9-2
Program Design Steps

[58] In the context of this document, "EE programs" consist of both energy efficiency/conservation and demand response programs and "EE measures" consist of both energy efficiency/conservation and demand response measures.

This chapter describes the four main program design steps in detail. Note that the program design steps discussed in this chapter are generically presented and are applicable to both energy efficiency and demand response programs. However, a more in-depth discussion specific to demand response programs is provided in later in this chapter.

Identifying Target Markets and Customer Needs

Much of the EE program planning process revolves around understanding the load shape impacts and costs of EE measures, and certain quantitative program characteristics such as aggregate penetration rates. Program design, however, requires a much more detailed understating of customers and trade allies. Program design professionals have effectively adapted a wide range of market research and program development methods that have been used successfully in other industries. A cornerstone of the market research process is market segmentation, or the division of a large class of customers into smaller groups with similar characteristics which are useful for designing (and implementing) EE programs. Traditionally, utilities have done very limited market segmentation, rarely going beyond segmenting customers by rate schedule, energy usage, size, or location. However, as utilities' program objectives become more varied and the measures more specific, more refined methods of segmentation and research on customer needs are required in order to customize a program's design features and implementation approach.

For example, many utilities' EE program departments start with one program, perhaps simple lighting rebates for a few types of equipment, promoted broadly through customer classes. As their efforts grow, they typically refine the original program, adding customized construction, and initiatives to involve trade allies. These evolutionary changes entail segmenting customers to meet customer needs and program goals more effectively. From such experiences, program designers have learned the benefits of performing market segmentation and program targeting more systematically as well as earlier in the design process.

The benefits of performing market segmentation are:

- better attainment of load shape objectives
- greater cost-effectiveness
- better market intelligence

In particular, segmentation allows program designers to target equipment types, incentives, and delivery mechanisms to specific audiences. In this way, program designers can reduce uncertainty and risk, and most importantly, reduce the cost of attaining program goals.

Segment Target Markets and Customer Types

There are three principal ways to segment markets:

1. *By Quantitative Building or Facility Characteristics*: Energy use and load shape characteristics, saturation and penetration of specific kinds of equipment, building age and construction type, building size, and other "hard" variables can be obtained from load research and modeling analyses and structured surveys. These kinds of data are critical to understanding the physical impacts of EE measure options on customers. For example, in a residential air conditioning cycling program the program designer would want to target homes with a high saturation of central air conditioning whose peak A/C load is coincident with the system peak. Likewise, for a dynamic pricing program, the program designer may want to target residential customers with central air conditioning, electric water heaters, and/or pool pumps.

By Demographic Customer Characteristics: Demographic data on residential customer are often drawn from government census reports on age, family size, income, and ownership status. For nonresidential customers, it is often necessary to capture features such as functional usage (office, school, retail, etc.) and ownership characteristics. Such data would be used, for example, in designing a commercial lighting retrofit program to reach customers with long hours of lighting usage (such as retail) and with owner occupied facilities to avoid the "split-incentive" problem with leased space.[59]

By Attitudinal and Organizational Customer Characteristics: These variables can be as broad as the customer's attitude toward the utility and as specific as the financial criteria the customer uses to make investment decisions. The practice of "psychographics"—the segmenting of customers according to clusters of related attitudes and values—is an important component of newer market research methods. Psychographic variables include attitudes toward risk, value, comfort, convenience, choice, and reliability. Other variables include customers' decision-making styles, types of financial investment criteria, and perceptions of the credibility of sources of energy information. Such customer data could be used to segment customers by the payback period they would require to make a technology investment, or by the sources of information on energy equipment they consider most credible.[60]

Identify Priority End Uses and Program Options

A fundamental step in EE program design is to identify the customer end uses that contain the greatest potential for achieving desired load shape impact and the EE measure options that can best produce the impact in each end use category. If the research, planning, and screening accomplished earlier in the EE program process (see items #2 to #5 of Figure 9-1) have produced very specific customer end-use and measure option targets, the program designer need not repeat this step.

[59] Note that EPRI has recently published a report on the subject of customer segmentation that covers both demographic and psychographic dimensions of classifying customers: *Customer Preference and Behavior: Exploring Customer Segmentation for Utility Energy Efficiency Programs*. EPRI, Palo Alto, CA: 2008. 1016386.
[60] Ibid.

For example, if commercial office lighting has already been identified as an end-use target and selected T-8 fixtures, compact fluorescent lamps, fixture reflectors, and occupancy sensors as the preferred measure options, then no further refinements are needed during the design process. But if the previous research only lists commercial/industrial lighting as the end-use target and high-efficiency lighting as the measure option, the targets would need to be further specified during the program design process.

Given an individual utility's load shape objectives, it is usually not difficult to identify the end uses that show the greatest desired load impact and the technologies that bear the greatest cost-effective potential to achieve that impact.

Match Targeted Technologies to Market Segments

The end uses and technologies selected as having the greatest load impact potential need to be mapped onto specific customer groups. Load research, market research, and other data will indicate which kinds of customer facilities have the kind of end uses coincident load characteristics, and equipment saturations that are most suitable for the measure option the program is to encourage.

A second step in targeting market segments is to use customer attributes, as opposed to facility or building attributes. For example, a rebate program would not be an effective incentive for government agencies that are prohibited from accepting rebates; billing credits might be more appropriate for that market segment. If setback thermostats are the selected technology, one would not target the program to retirees who are home during the day and have different thermal comfort needs than the overall residential market. If a program involves substantial building shell modifications and the multifamily market segment is dominated by absentee ownership and syndicated financing, the program will suffer low participation unless it is designed for that audience.

As should be clear from these examples, matching technologies to market segments is a fundamental consideration in program design. If the load impact opportunity is great enough in a given market segment, the program designer may decide to target a program to this market segment despite potentially high barriers to participation. Small commercial lighting is an example of such a market segment, and the challenge is to design incentives and marketing techniques that will reduce the barriers. For small commercial customers, a full-service approach offering direct installation of EE measures is a typical solution.

Find Out More About Customer Needs in Targeted Market Segments

Finding out how customers think and behave with respect to EE technologies and programs can be a key factor in the success or failure of a program. The previous design steps have identified the end uses to be effected, the technologies to apply, and the customer groups that appear to be the best targets. To design effective programs for these customers, you need to know how they use energy, how they think about energy consumption, how they make decisions about buying energy-using products and what their foremost concerns are about certain kinds of products. To

obtain this information, program designers should examine the following attitudinal and behavioral variables:

- *Customer Concerns and Priorities*: Customer groups look at energy-using products and energy-efficiency services in different ways. A commercial property manager looking to replace worn-out cooling equipment may be concerned with occupant comfort, first cost, and reliability. A residential customer shopping for a refrigerator may view size, convenience, appearance, first cost, or energy usage as priorities. Other customer types may view appliance purchasing quite differently. A residential customer considering joining a dynamic pricing program may be concerned about understanding their energy usage and how to respond to the dynamic price. It is important to identify and account for these concerns and priorities into the design if the program is to succeed in the target markets.
- *Customer Behavior and Decision Making*: How customers make decisions, what financial criteria they use, how they typically purchase the kind of equipment eligible for the program, and budgeting cycles and buying seasons can all affect program participation.

Research on customer needs and attitudes can also identify the barriers to participation in the program. Typical barriers and possible program design solutions include:

- *First Cost*: Customers may be reluctant to pay a price premium for efficient products. The program may, therefore, include incentives designed to offset this incremental cost.
- *Stringent Investment Criteria*: Commercial customers may require a payback period or internal rate of return (IRR) that eligible products cannot meet. Again, program incentives should be structured to provide an effective payback or IRR that meets customer criteria.
- *Aversion to Risk*: New technologies may be perceived as unreliable or unproven. To build customers' familiarity with and confidence in the technology, a program could include "free trial" demonstrations, case study materials on successful applications elsewhere, and training and education sessions for customers and trade allies. Risk aversion is especially important for dynamic pricing programs where customers may want to have side-by-side billing for a few months or an energy usage monitor so that they can become familiar with how to shift their energy usage.
- *Customer Choice*: If an EE program is restricted to a few specific products or services, or a rigid incentive structure, it may not appeal to some customers' brand preferences, specialized equipment needs or buying practices. To reach these kinds of customers, a program can be designed to include customized equipment options and incentives. Greater openness in product choice can be provided by using a set of qualifying criteria rather than a specific list to determine product eligibility. This approach also allows the incentive to more closely match the actual impact of the technology. In the case of demand response programs, the customer choice issue is typically whether a dynamic rate will become the default rate (replacing the flat rate) or whether customers will have a choice to adopt the dynamic rate.

Finally, research on customer needs and attitudes can identify gateways to participation (e.g. the specific customer types most likely to respond positively to a program, particularly appealing program features, and the market mechanisms that offer easiest access to customers). Typical examples include:

- *Early Adopters*: In any customer population there are those whose psychographic attributes and other characteristics predispose them to try new technologies for reasons beyond straight economic analysis. Program marketing can shape messages to reach this part of the market effectively.
- *Trade Allies*: Educating and involving trade allies in program delivery can reduce program costs and increase participation. Programs that target residential appliances and basic commercial equipment types at the time of natural replacement can thrive on trade ally promotion.
- *Customer Impulse Buying*: Consumer product companies have capitalized on consumer impulse buying by mounting point-of-purchase displays linked to their promotion campaigns. Such techniques invite customer participation in the course of daily shopping. EE programs aimed at residential technologies such as lighting and weather stripping can adopt this marketing strategy with great effect, especially if retailers are carefully recruited to support it.

Designing Program Features to Meet Utility and Customer Needs

Establish Specific Program Objectives

Once general agreement is reached on the purpose of a program—for example, to increase use of efficient lighting in commercial customer facilities—it is essential to list objectives as specifically as possible. The technology selection, market segmentation, and customer needs assessment steps described previously should provide the information needed to establish specific program objectives. Using the general goal of increasing the use of efficient lighting as an example, specific objectives might include:

- Encouraging installation of a priority list of targeted technologies (such as T-8 fluorescent lamps and ballasts);
- Reaching a priority list of target market segments (such as large C/I customers and chain operations);
- Responding to customers' needs and priorities (such as T-8 reliability, simplicity of participation, and maintaining light level and quality);
- Reducing specific market barriers for target customer groups (such as high first cost of T-8 equipment, lack of understanding of T-8 benefits, and lack of understanding of T-8 applications);
- Learning more about market response to EE programs; testing planning assumptions about market conditions, program participation and program impacts (for example: will trade allies promote T-8s? Will customers retrofit lighting fixtures at the projected rate? Will T-8s produce estimated coincident peak reductions?);

- Building program design and implementation capability within the EE program organization and staff (e.g., testing a program tracking system, building staff capability to communicate with customers, building administrative capacity to handle participation in volume);
- Meeting specific regulatory directive from utility commissions or other bodies (e.g., load deferral targets, budgetary constraints, program evaluation standards).

Refine Technology Selection and Eligibility

An effective EE program must specify which equipment is eligible for inclusion and how eligibility is to be determined. Consider the following factors in defining product eligibility:

- *Maximum Performance versus Customer Choice*: Selecting a small number of the highest-efficiency products, or those that rank highest in cost-effectiveness, can serve the program's load-impact-per-customer objective, but limiting customer choice may curb participation. Offering a broad menu of products may make it easier for more customers to participate, but can increase freeridership, reduce per-customer impacts, and erode cost-effectiveness.
- *Specific Listed Products versus Generic Eligibility Criteria*: Some programs list eligible products by make and model number. Others prescribe specification and performance criteria. The former approach is more transparent and creates less work for customers and trade allies. The latter allows for creativity and broader customer choice and reduces product availability and vendor stocking problems, but may make the eligibility determination process more cumbersome.
- *Product Availability*: Can vendors supply needed quantities of eligible products in the program's time frame? Are eligible products available from more than one manufacturer?
- *Market Awareness and Usage*: Are customers and trade allies sufficiently familiar with the eligible products? What are current saturation estimates for the particular class of equipment and penetration estimates for eligible models?
- *Free Ridership Potential*: Including products with low costs and significant pre-program market penetration such as T-8 fluorescent lamps and electronic ballasts for commercial customers will encourage higher free-ridership. To prevent this, a program can emphasize products with higher price premiums and lower market penetration such as T-5 lamps for commercial customers. In addition, load management programs typically have low free ridership rates since very few customers tend to shift load without an incentive such as a control device or a time-of-use rate. Table 9-1 provides examples of some typical relationships between EE measures and free ridership potential.

Table 9-1
Examples of Free Ridership Expectations

Free Ridership Expectations	Residential	Commercial/Industrial
High	High-efficiency room air conditioner; Compact fluorescent lamps	T-8 fluorescent lamps; LED exit signs
Medium	Weatherization retrofits; High-efficiency kitchen appliances	HVAC economizers; High-efficiency chillers
Low	Air conditioner cycling; Water heater direct load control	T-5 fluorescent lamps; Variable air volume HVAC systems; Thermal storage

In determining final product eligibility, program designers must rely on sound market research and clear EE program marketing objectives as they seek to balance the various competing factors.

Refine Customer Eligibility

Some customer eligibility criteria may derive from factors other than market segment and customer type targeting. These may reflect evaluation requirements, logistical constraints, or utility policies. Typical examples of additional eligibility requirements include:

- *Account Longevity*: Some programs require accounts to have been active for a minimum period or to show the likelihood of remaining active for a minimum period. Such requirements help assure adequate pre-and post-installation billing data, and can be used to screen out new buildings, if that is desired or to exclude customers likely to close facilities in the near future.
- *Location*: Many programs, especially in the pilot phase, limit their geographic scope to control costs and other factors. Utilities spanning regulatory jurisdictions may need to limit program eligibility to that portion of the service area under a specific regulatory body. For example, to more carefully control T&D capital costs, some utilities are focusing EE programs on the needs of operating regions. Also, for dynamic pricing programs, advanced metering infrastructure (AMI) is a prerequisite. For example, if AMI is being deployed geographically among residential households, a dynamic pricing pilot or program should be limited to households with AMI.
- *Full Service Customers*: Utility policy may preclude offering EE programs to larger customers pursuing self-generation and cogeneration options, especially if customer-owned generation is for peaking or load-following purposes, and would not necessarily affect the utility system's peak demand.

Design Financial Incentives

Financial incentives are considered when performing cost-effectiveness analyses of EE programs (this topic is discussed in detail in Chapter 10). Incentives are an important and necessary input for the cost-effectiveness analyses, and thus need to be determined during the program design stage. The specification of financial incentives is oft considered the most important step of program design. However, other program aspects are equally important. Moreover, as discussed in the subsequent sections in this chapter, financial incentives are but one type of incentive.

Nonetheless, financial incentives are usually central to an EE program, as they are the "carrot" offered to the customer to influence equipment purchase and energy usage decisions. The importance of properly designing financial incentives cannot be overstated.

There are three basic steps to designing incentives: (1) define the incentive range, (2) select the incentive level, and (3) define the incentive structure.

1. Define the Incentive Range: Incentives must be high enough to motivate customers and low enough to stay within the utility's economic constraints. The maximum of the acceptable range for incentive payments is typically based on the utility's resource value for the incentive, often expressed as avoided capacity and/or energy costs. The minimum is defined by the incentive level that meets customers' financial criteria, such as a maximum payback period or a minimum internal rate of return. For a specific type of equipment, one can translate the avoided cost and customer criteria data into specific dollar values by calculating the energy and demand savings expected from the equipment. It may be prudent to discount the resource value cap to allow for free ridership, capacity equivalence factors, and overestimation of savings, among other factors.

Select the Incentive Level: To find a point in the incentive range that is likely to trigger customer participation, one uses information such as financial performance thresholds (one-year and two-year paybacks are often cited) that market research indicates will motivate participation. If, for example, the bottom of the incentive range is defined as the equivalent of providing a three-year customer payback, one may consider a higher incentive level that reduces the average payback to two years. This calculation is very specific to the equipment involved, its price premium, and estimated energy and demand savings. It is particularly important to use realistic installed cost data, including labor and markups, for specific equipment configurations; generic equipment price estimates are inadequate. Table 9-2 shows an example of one approach that may be used to establish the range of possible incentives and selecting the incentive level. This method for setting incentive levels avoids the drawbacks of simpler approaches. For example, using resource value as the sole basis for setting rebate levels requires less research into customer preferences and actual equipment costs but risks overpaying for some measures and incurring high free-ridership.

Table 9-2
Example of an Approach Used for Selecting the Incentive Level

Step 1: Estimate Maximum Rebate Level	Avoided Energy Costs (A)	Energy Savings [kWh/yr] (B)	Avoided Capacity Cost (C)	Avoided Capacity [kW] (D)	Resource Value of Savings (A x B)+(C x D)
	$0.03 / kWh	1,080	$550 / kW	0.09 kW	$81.90
Step 2: Estimate Maximum Rebate Level	Customer Energy Savings [$/yr] (A)	Installed Equipment Cost [$] (B)	Simple Payback without Incentive (C)	Customer Minimum Financial Criterion (D)	Incentive Needed to Meet Criterion B - (A x D)
	$37.80	$155.00	4.1 years	3 years (simple payback)	$41.60
Step 3: Select Rebate Level (basis: reduce simple payback to two years)	Customer research shows two-year payback would be attractive. Multiplying customer annual energy savings ($37.80) by 2 yields the maximum customer cost for two-year payback ($75.60). Subtracting this amount from the installed equipment cost ($155.00) yields the incentive needed to give the customer ran effective two-year payback.				Selected Rebate Level
					$79.40

Define the Incentive Structure: The incentives most commonly used in EE programs include fixed rebates, customized incentives, and specialized incentives.

- *Fixed rebates*: Rebates may be based on incremental or installed equipment costs. They may be offered in the form of detailed tables with a fixed amount for specific equipment configurations, or they may be applied to categories of equipment that meet certain criteria. If there are several levels of efficiency within an equipment category, a sliding scale of rebate levels may be linked to equipment efficiency; for example, as the energy efficiency of central air conditioners increase, the rebate level increase. This sliding-scale approach can limit "cream-skimming" (the overuse of the most attractive measures) and increase program impacts per customer.
- *Customized or calculated incentives based on dollar per unit of savings*: Some EE measures are so application-dependent, or may be so new in the service area, that it is difficult to develop fixed incentive levels with adequate confidence. In such cases customized incentives can serve to tailor the program to customer needs while keeping incentive payments in line with cost-effectiveness targets.
- *Specialized incentives*: Incentives may involve financing as well as, or in lieu of, direct incentive payments. Examples include loans with interest or principal possibly subsidized by incentive funds, performance contracting and shared savings arrangements, or direct installation.

In general, simple incentive structures can be used with clearly specified equipment, are easy for the customers to understand, and are easy for the utility to administer. The fixed rebates are the most common incentive structure for most first-generation EE programs. As the EE program organization gains experience and customers learn more about the program, equipment incentives often evolve into more complex and varied formats reflecting the particular characteristics of the equipment and customer preferences.

The choice of incentive structure turns on two basic issues. First is the issue of simplicity versus effectiveness. Fixed rebates are the most widely used incentive structure because they are the simplest; yet to the extent that they fail to meet customer needs or overcome market barriers, their effectiveness can be limited. Customized incentives can be more responsive to the market, but they can entail high transaction costs and can be confusing to some customers. The second key issue is utility orientation versus market orientation. Many programs contain incentives that are very rational from the utility's viewpoint: their economics are appealing and they reward customer choices that support the utility's objectives. Yet these incentives may not work for some technologies or in certain market segments. For example, incentive levels based on incremental equipment costs may not spur much activity in markets where the natural replacement rate is low; if the utility has planned the program to generate high annual participation, the program's results are likely to fall short. Some market segments may not respond to economic incentives because of other barriers; government and nonprofit institutions, for example, are often unable to use conventional rebates because they lack the discretionary or capital funds needed to make the original purchase. Specialized financing approaches may be more effective in reaching such customers.

Design the Service Package

Once the financial incentives are established, it is usually embedded in a package of services that invites customer participation. A rebate, for example, may be offered in a direct-mail brochure that offers free energy audits and customer workshops. The goal is to design a total service package that presents the financial incentive and overcomes other barriers to customer participation, such as lack of information, lack of design expertise, or lack of time to arrange the transaction. To the extent that program services reduce these barriers, they should be treated as incentives.

Simple program designs may offer a single service, such as an energy audit, combined with a financial incentive. More complex programs may provide a more sophisticated package or menu of service elements; among the most commonly used in EE programs are:

- *Facility Energy Surveys*: Although the industry is moving away from the stand-alone energy audits of the 1970s and 1980s, facility surveys remain valuable tools if packaged correctly. At the least, they provide baseline information on customers' building equipment, usage and load shapes, and savings potential. This information is valuable for load research, market research, and program planning, even if the customer goes no further. Facility surveys are also a way to improve relationships with customers.
- *Education and Training*: From one-day workshops that introduce customers and trade allies to a new technology or program, to extended courses for training and certification in special skill areas, more utilities are responding to the need to educate their customers and trade allies. This kind of service not only stimulates market awareness and use of specific technologies, it also builds an infrastructure of more knowledgeable customers and trade allies attuned to future EE efforts. These programs also enhance community and industry attitudes toward the utility.

- *Design Assistance*: Some EE programs offer direct technical services to building owners and design firms whose lack of expertise might discourage them from investing in new technologies. Services can include building surveys, design drawings and specifications, and economic analyses of costs and benefits. Design assistance can help the customer understand not only the technical aspects of the EE technology but also its broader benefits.
- *Installation Assistance*: EE programs may offer customers a list of vendors or installation contractors to reduce "shopping" time. To build consumer confidence, some utilities develop "approved" or "certified" lists of installers, though this process can be costly and may raise liability issues in some areas. A less cumbersome option is to publish lists of vendors or contractors who agree to as set of program practices, without formal certification from the utility. Some programs include direct installation services; when the customer signs up, the job is assigned a crew (often under contract) for direct installation.
- Financing Assistance: Some programs arrange for traditional consumer loans that customers repay through charges on their utility bills. Other programs offer below-market interest rates, zero interest rates, or flexible repayment terms. "Performance contracting" (discussed below) covers a variety of financing methods in which utility incentive payments are linked to the energy savings produced by the installed equipment.

Service packaging brings together these elements into "bundles" designed to meet certain customer needs. Three of the most common service packaging approaches used in EE programs are:

- *Turn-Key Direct Installation*: In this type of program, utility personnel (or utility contractors) handle the entire transaction for the customer. They survey the facility, install the measures, perform inspections, and conduct related services. The program may involve 100% financing, or may require partial payment from participants. This approach is appropriate when the full installed cost of the measures is justified by cost-effectiveness tests. It is typically useful in the following cases: (1) when the market infrastructure for the EE measures is under-developed; (2) when the pool of potential customers is small or consists of less technically savvy customers; (3) for relatively simple and low-costs measures; or (4) in order to achieve a high participation rate. Direct installation, where feasible, can result in higher quality and superior performance of installed measures, and yield more persistent savings.
- *Comprehensive Services*: In this kind of program, the utility typically offers the customer all the services needed, from first inquiry through installation and financing. Alternatively, the utility can offer a menu of services from which customers can choose what they need. These programs usually do not offer direct installation, however; customers are referred to contractors and financing options available in the market. This approach typically incurs fewer "hard" costs than direct installation, but can incur high "soft" or transaction costs—the technical assistance and hand-holding that may be needed to help customers through the decision process and "closing the sale."

- *Performance Contracting*: During the 1980s a small industry developed based on the concept of paying for energy retrofits out of the saving they generated. Spawned as "shared savings" arrangements in which each dollar of savings is split between the customer and an energy service company (ESCO)[61], performance contracting has evolved into a variety of forms. But the basic principle remains the same: the customer bears no up-front costs, and any downstream payments are covered by utility bill savings. In some utility-sponsored performance contracting programs, the utility allows one or more ESCOs to install certain EE measures in certain markets. The utility then pays the ESCO based on the energy and demand savings achieved for the customer. Other variants include loans repaid by customers through utility bills, with the payments structured to be less than expected energy savings.

Select and Develop Delivery Mechanisms

EE program design must include careful choices about how to deliver the program to customers and what distribution channels to use. Before putting a program "on the street," designers should assess the program from a market vantage point and structure its delivery so as to make best use of existing market mechanisms.

Delivery mechanisms and program services help to define each other. Delivery mechanisms can be seen as the "how" of the program, services as the "what." Many of the basics of program delivery are also dictated by the program features designed in the earlier steps, such as eligible technologies, eligible customers, and incentive structure. Components of the delivery mechanism typically include the following:

- *Equipment Availability*: Manufacturers and local vendors must be able to supply sufficient eligible products in the time frame the program requires. Sales are likely to be particularly brisk for lower-cost "off-the-shelf" items like compact fluorescent lamps or room air conditioners. Product shortage not only limits program participation but create frustrated customers who are less likely to respond to future promotions.
- *Role of Trade Allies*: Incentives may be offered through trade allies such as equipment vendors, installation contractors, and design professionals. Trade allies may also play key roles in marketing, installation, and quality control. Trade allies are particularly valuable partners in commercial/industrial programs geared to the natural replacement market. For example, in an electric motors rebate program, electrical equipment suppliers can be enlisted to call customers' attention to higher-efficiency equipment as they come in to replace worn-out motors. In such a market-driven program, the utility's marketing costs are greatly reduced.
- *Support Services Delivery*: Decisions must be made about the timing, location, and staffing of training, design assistance, energy auditing, and other services. Development of support materials must be arranged. If services are offered in a package, the coordination and delivery of these service packages must be defined. Coordination is especially important in commercial/industrial programs offering comprehensive services. For example, in a comprehensive C/I lighting program, the EE program manager may schedule a series of orientation and training workshops prior to the formal announcement of the program. The

[61] An ESCO is an entity that performs analytical, installation, financing, and maintenance services at no initial cost to the customer.

workshop leaders may then be assigned to design assistance teams to work with customers and trade allies. The manager may contract for energy audit services and distribution of program materials such as application kits, promotional literature, and case studies.

Developing Methods for Marketing EE Programs

In the context of designing and implementing EE programs, marketing is more tactical than strategic, encompassing the promotion, recruitment and sales aspects of the program. By contrast, strategic marketing is a long-term process carried out at the level of overall corporate planning. Whereas selling focuses on products and their competitive attributes, marketing focuses on customer needs and satisfaction. The marketer's job is done when the customer is satisfied with the program.

The opening sections of this chapter highlight various ways to orient a program to customer needs and concerns. These form the basis of the marketing effort which is then refined to suit the products, incentives, mechanics of program delivery, and trade allies involved.

Align Marketing Mechanisms and Media to Customer Decision Stages

Customers typically go through five stages in reaching a decision on EE program participation. At each stage, customers need different kinds of messages and information:

2. *Awareness*: Many new energy technologies are virtually unknown to many customers. To create basic awareness of the technology and of the EE program, introductory information should be relayed through customer newsletters, brochures, radio and TV ads, talk shows, public exhibitions, and cooperative ads with trade allies.

Understanding the Applications: At this stage the customer knows that the technology and the EE program exist but needs to learn about how the technology might be put to work in his or her home or facility. Visual media are effective at this stage: illustrated literature, live demonstrations, personal sales presentations, and TV or video messages.

Evaluation of Benefits: Once the customer understands the uses of the technology, he or she begins to weigh the benefits and costs. At this juncture the most effective marketing medium is personalized service: a facility survey, or a call from an account representative.

Motivation: Some customers feel motivated to make the participation decision as soon as they hear about a program. Others may respond to personal sales presentations, peer influence, or detailed descriptions of the benefits of the program incentive.

Adoption: When a customer is ready to go ahead, he or she needs an easy way to say "yes." Convenient methods for enrolling participants include postage-paid return cards with check off boxes, rebate forms at the point of purchase, and bill envelope tear-offs.

Table 9-3 illustrates how marketing mechanisms might be linked to customers' decision-making stages.

Table 9-3
Matching Marketing Media to Customer Decision Stages

Stage	Illustrative Types of Media
Awareness	Bill insert Brochure Radio ads Cooperative ads with trade allies
Understanding the applications	Visual presentations Hands-on demonstrations Personal sales presentation TV spots
Evaluation of benefits	Energy audit at customer facility Customer service rep contact Detailed case study information
Motivation	Peer persuasion / word of mouth Personal sales Financial incentives
Adoption	Phone contact Check-off response cards Point of purchase rebate form

Match Marketing Messages to Customers' Key Needs and Concerns

The earlier steps of market segmentation and research on customer needs and attitudes should provide information on how customers think and feel about energy equipment and programs. This information should be used to identify marketing messages that will appeal to specific audiences. For example:

- In a residential air conditioning cycling program, frugal customers will respond to the message of monthly bill credits, while customers concerned more with comfort and convenience will need to be assured that the program will not significantly raise indoor temperatures or otherwise disrupt their household. Customers focused on reliability will want reassurance that their equipment will not be damaged, and they will be interested in know how similar programs have worked elsewhere.
- A New York utility identified six market segments for designing its marketing approach in an electric thermal storage program. After identifying the primary target segments, the program staff designed a promotional campaign that appealed to these customers' specific needs.
- In a commercial lighting retrofit program, property managers may need to be shown that adopting the new equipment will not lead to tenant complaints, new maintenance requirements, or additional costs. Marketing messages can respond to these concerns by showcasing tenant testimonials from other installations, quoting satisfied property managers, and showing how much the incentive structure makes the investment affordable.
- In the same commercial lighting program, the major issues for owner-occupants may be lighting quality, financial performance, and worker productivity. In this case, in-depth research and case study material may be needed, backed up by thorough financial analysis. The results can be marketed through fact sheets that focus on quantitative benefits and detailed case studies (including customer testimonials) from other installations.

Because marketing messages must be tailored to customers' needs, EE program designers cannot simply turn to a cookbook of tried-and-true messages. Many utilities employ marketing and advertising firms to assist them in identifying and articulating the messages that will work best in their markets.

The marketing messages should also be matched to an appropriate medium:

- *Information Packages*: Packages can range from simple, consumer-oriented brochures mailed as bill inserts to technical product or case study literature that is mailed or delivered personally by utility representatives.
- *Print Media*: Public information announcements and press release may generate news articles. Newspaper, trade press, and cooperative trade ally advertising can be well-aimed and cost-effective vehicles in some service areas. Trade press and trade co-op advertising can be particularly cost-effective; providing advertising materials to trade allies or sharing the cost of advertising space are examples of this approach.
- *Broadcast Media and Collateral Promotion*: Radio and TV ads, often supported by point-of-purchase displays or giveaway items printed with the company logo and program identification, are well-known avenues for marketing programs with wide market targets. But the broadcast media, especially TV, can be very expensive if the target market is relatively small relative to the media audience or if the target market is unreceptive to media messages. Cable TV and radio are lower in cost and easier to direct to target audiences; radio station formats, for example, are often aimed at particular demographic groups.
- *Direct Customer Contact*: Direct contact may be selective (scheduled appointments by established account representatives to make a specific program presentation) or diffuse (a "neighborhood blitz" to promote residential use of compact fluorescents). Direct contact can elicit high response rates, but typically at a high cost per customer; direct contact is also inefficient at reaching a large number of customers. For these reasons, direct contact is usually most cost-effective when the program is aimed at large per-customer impacts. For example, many utilities assign account representatives to their largest customers and use these existing relationships to introduce EE programs.
- *Educational/Technical Services*: Program services such as workshops, technical assistance studies, or design services can also be effective marketing tools. Because they often give something of value to the customer, they improve customers' receptivity to utility programs. While it is difficult to assess the cost-effectiveness of such methods, they often are rated highly by customers in terms of value.
- *Telemarketing*: Telemarketing can often obtain higher participation rates, at reasonable costs, than more passive methods such as direct mail or media campaigns. However, telemarketing is viewed as intrusive by many consumers, and it may alienate some customers.

Although the range of choices in designing a marketing effort is quite broad, the process of shaping an effective marketing effort need not be complex. Attention to four general principles can be used to focus almost any marketing effort:

1. *Design the marketing effort from the customers' point of view*: It is very easy for program staff to become absorbed with the utility's objectives, operating style, organizational structure, and other internal factors. It is always valuable, often essential, to stop and ask "What will make it easy for customers to sign up for this program?" Some of the basic guidelines are:
   - *Simplicity still works*: Give the customer clear and complete information and ask for a simple decision.
   - *Make it easy to respond*: Include postpaid response cards and a phone number.
   - *Personalize service*: Program materials should reflect an understanding of the customer's situation and should show that the program is aimed at the customer's needs. If the size of the target market permits, offer the names of people to contact for further information.

2. *Clearly define the role of the trade allies*: Working with trade allies usually entails tradeoffs. Trade allies can greatly magnify the reach of the marketing effort, but relying on trade allies costs EE program staff a measure of control; trade allies can help reduce overall program administrative costs, but they may influence customers' decisions in way that limit a program's impact. Ideally, the program design should enlist enough ally involvement to attain the leverage benefits, but exert enough control so that trade ally activity is focused along the lines the program intends. One way to achieve this goal is to involve trade allies early in the design process. Use focus groups or surveys to identify their needs and concerns and solicit their response to design concepts. After the program is launched, education and training can ensure that allies understand and follow program guidelines.

3. *Locate the marketing campaign responsibility carefully*: Lead responsibility for running the marketing effort may be assigned to the EE program department, the utility's public affairs department, the utility's existing advertising and PR firm, or a new outside marketing or advertising firm. Here again there is a tradeoff between control and effectiveness: Doing everything from within the EE program department retains maximum control but may not garner support from the rest of the company, or reap the benefit of creative ideas from advertising professionals. Contracting out the marketing effort may produce greater promotional "punch," but at the risk of overrunning the basic features of the program.

4. *Relate the marketing message to other utility messages*: As EE programs proliferate, it is increasingly important for a utility to present a coherent image to its customers. Potential synergies or conflicts between program messages and other utility communications efforts should be explored with the communication department before the marketing effort is launched. Conscious decisions must be made on whether and how to link the utility's various messages.

Develop Indicators of Program Impacts

Specific program features such as budget, incentive levels, eligible equipment, size of the eligible customer population, program duration, and marketing resources will all affect the program's real impact in the target market over a given time period. These factors also affect the cost-effectiveness of a program.

In order to prepare for the cost-effectiveness evaluation (discussed in Chapter 10), it is necessary to develop three primary indicators during the program design phase that can be used to estimate a program's impact prior to implementation. These three indicators are: (1) participation rate, (2) market penetration, and (3) energy and demand impact. While the planning process should produce reasonable estimates of the unit impacts of EE measures, the impact of the program over a given time period will depend on the participation and market penetration rates produced by the program. This section briefly describes how to develop the three indicators of a program's impact once the detailed program design has been established.

Participation Rate

An EE program's participation rate may be defined in three ways:

1. Percentage of customers eligible for the program who participate within a fixed time period
2. Percentage of eligible customers who were reached by the marketing effort (i.e., those who had the direct opportunity to participate) and chose to participate; and
3. Percentage of customers in the market for a given type of equipment during the program cycle who participate in the program.

For example, if 100,000 residential customers are eligible for an A/C cycling program and 10,000 sign up in a given year, the participation rate would be 10%. By the second, narrower definition, if only 30,000 customers of the 100,000 are made aware of the program and 10,000 sign up, the participation rate is 33%. The third definition, even narrower, applies to programs like those aimed at refrigerator replacement: If there are 100,000 eligible residential customers, but only 7,000 buy refrigerators in a typical year, the practical limit of the target population is 7,000. If 2,000 of those customers participate in the program, the participation rate would be only 2% of the total residential class, but almost 30% of those active in the market for that year.

For a realistic expectation of program performance, participation estimates should be refined from the original planning estimates. The original estimates may have, for instance, projected that 50% of commercial customers would participate in lighting programs. However, the market segmentation, incentive design, marketing plan, and other features of the program—constrained by annual program budgets—may limit first-year participation to 5%. Annual, perhaps even quarterly, estimates of EE program impacts must be developed for utility planners responsible for near-term resource projections. If, for example, a direct load control program has a goal of 100,000 customers, but only 25,000 will have completed installations before the next summer peak season, that information must be available to system dispatchers.

Market Penetration

Market penetration is a somewhat different measure than program participation. Participation is measured in customers; penetration is measure in physical units. In a commercial lighting program, for example, 5,000 of an eligible 100,000 customers may participate, yielding a participation rate of 5%. But if the program affects 8,000 of the 25,000 fluorescent ballasts sold annually, the program achieves 32% market penetration. A program can also experience high program participation with low market penetration. For example, in a compact fluorescent program, 20% of eligible customers may participate; but if these customers average one lamp each perhaps only 5% of total incandescent lamps can be affected.

When an EE program is aimed at affecting sales of equipment, the penetration rate is measured as the percentage of sales of equipment of a given type that was captured by program-eligible equipment. Penetration data can be cumulated in saturation rates, a measure of the presence of a given kind of equipment in the total population under examination. For instance, if 95% of all residential customers have refrigerators, refrigerators are said to be 95% saturated in that population. If 25% of customers with refrigerators have efficient models, then the saturation of efficient refrigerators is 23.7% for all customers and 25% for customers with refrigerators.

Energy and Demand Impacts

Analyses conducted during the measure screening and savings potential of the EE program process will typically produce projections of EE measures' energy and demand impacts, both on a per-unit basis (Chapter 6) and on an aggregate basis (Chapter 8). While these are valuable guidelines, it may be necessary to refine the assumptions and redo the analysis once the specific program features have been selected. Two kinds of refinements usually need to be made:

- *Per-Unit Savings Assumptions*: For planning purposes, the general characteristics of the EE technology and the equipment it will replace are sufficient. As the program design process more carefully identifies eligible equipment and the typical equipment to be replaced, the per-unit energy and demand impacts may need to be adjusted.
- *Number of Units Installed*: Planning may project participation rates based on the size of the eligible population and penetration rates based on total sales of target equipment types (e.g. the market acceptance rates discussed in Chapter 8). However, program constraints such as funding, time, and market barriers can limit the actual number of eligible customer enrolled in a given time frame. Estimates of load impacts may need to be refined according to actual expected participation rates and the number of units to be installed per customer.

It is simplest to develop impact estimates for programs that offer fixed incentive payments. If you assume the program is fully subscribed, you can simply divides the total incentive funds by the incentive paid per unit. For example, if $500,000 is available for rebates in a compact fluorescent retrofit program, and the rebate is $5 per unit, then 100,000 units will be involved in the program. Multiplying these 100,000 units by per-unit energy and demand impacts would provide a reasonable impact estimate.

This simple approach does not account for free ridership, take-back effects, and other factors that can affect a program's true net impacts. These issues are explored in Chapter 12.

Refining energy and demand impact estimates can be more complicated where there are multiple rebates for multiple equipment types, tiered rebates, customized/calculated rebates, or more complicated incentive structures. The problem is even more complicated when program design is not based on fixed incentive payments but offers a package of services whose impact is harder to quantify. In such cases, it is usually necessary for the program designer to determine the weighted average of the impacts due to the individual measures in order to derive the impacts of the package as a whole.

Demand Response Program Design

This section summarizes a few issues that are of particular importance in designing dynamic pricing demand response programs.

Dynamic Prices and Enabling Technologies

A fundamental decision for the program designer is the "rate design" for the dynamic price and the specific type of dynamic price to offer (e.g., TOU, CPP, RTP). Dynamic pricing experiments over many years have shown that customers do respond to price signals; the higher the price the greater the overall response. In addition, customers with enabling technologies (e.g., a smart switch or a smart thermostat) respond more to dynamic prices than those without such technologies. Finally, customers in more extreme climates tend to respond at higher rates than customers in moderate climates. Hence, the program designer must determine a rate that is both acceptable to customers and high enough to elicit a load reduction that results in significant value. In addition, the program designer must determine which types of enabling technologies will be available to customers and the price (if any) for these technologies.

Customer Choice

For dynamic pricing programs, a second critical design element is whether to offer the dynamic price as the default rate replacing the current rate (i.e. an opt-out option) or to give customers a choice to adopt the dynamic price (i.e. an opt-in option). As discussed earlier, there are several steps in the customer decision-making process that ultimately lead to the adoption decision. Lack of interest, lack of awareness, and other factors make it difficult for customers to switch from an electricity rate that they are very familiar with to a new rate. As a result, it is difficult to obtain high market penetration rates for dynamic pricing programs under an opt-in design. Alternatively, although the opt-out design will result in a high market penetration rate, customers may not like the idea of being automatically switched to a dynamic price. However, it is important to point out the most of the gains in energy efficiency over the past few decades have been a result of mandated standards and codes for energy efficient appliances, end-uses, and buildings. The market penetration rate will significantly affect the overall impact of the program. Whether to offer dynamic pricing as an "opt-in" or and "opt-out" program is a major decision facing the program designer.

Eligibility

Advanced metering infrastructure (AMI) is a prerequisite to dynamic pricing programs such as CPP and RTP. This is a primary eligibility criterion for dynamic pricing that the program designer must consider. Therefore, it is often useful for the dynamic pricing program designer to work closely with the AMI team.

Incentives

Since dynamic pricing programs result in bill savings if the customer responds to the price signal, financial incentive are typically not offered for these programs. However, in pilot programs, customers have expressed interest in energy monitors or other devices that display their energy usage. Such devices could be offered as incentives for dynamic pricing programs.

The Retail-Wholesale Nexus of Demand Response at RTOs

Because much demand response in RTOs comes from retail customers (with ERCOT being an exception), there is a nexus between retail and wholesale issues for demand response at RTOs. RTOs are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC).[62] Issues such as whether states approve retail choice, the use of time varying rates, or the ability of third-party aggregators to work directly with the RTO have an impact on DR participation in an RTO. For example, in California, third-party aggregators currently have to work through investor owned utilities (IOUs) whereas in PJM they do not. As a recent article co-authored by a FERC Commissioner points out:

> …states have traditionally regulated demand response and that they will continue to play an important role in cultivating its full benefits for electricity consumers. Therefore, this article further contends that enhancing coordination of federal and state initiatives offers the most promising approach to managing the jurisdictional overlap in this area. [63]

Retail DR is in the provenance of state regulatory commissions. Traditionally, the implementation of EE, including DR, was at odds with a utility's financial interests. A decrease in sales volumes results in a decrease in revenues leading to a decrease in profits. In order to encourage utilities to invest in energy efficiency and DR programs, some states enacted tariffs whereby utilities are, in effect, held harmless from decreases in sales volumes due to DR or energy efficiency efforts. Rates are "decoupled" from the effects of DR programs, hence encouraging utilities to invest in DR. States that have enacted decoupling indicate a propensity for DR compared with other states.

[62] ERCOT is not FERC jurisdictional and is a special case. Though it, too, faces regulatory issues that affect its ability to incorporate DR, it does not face the same Federal-State jurisdictional divide that the other RTOs face.
[63] Hon. Jon Wellinghoff and David L. Morenoff, "Recognizing the Importance of Demand Response: The Second Half of the Wholesale Electric Market Equation", *Energy Law Journal,* Vol. 28, No.2, 2007.

Ultimately, retail and wholesale demand response compete for the same demand response resources. To the degree that retail programs are not integrated with wholesale programs at RTOs—for instance, through limitations on the role of aggregators—the potential for increasing demand response at RTOs will be limited.

Summary and Resources

This chapter lays out the basic steps that a program designer should complete before offering a program to customers. The issues raised here form an important bridge between the analytical world of program planning and the practical world of program implementation. Effective program design helps translate the utility's EE program objective into terms that appeal to customers and will work in the marketplace.

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10
MEASURING COST-EFFECTIVENESS

Background

Assessing the cost effectiveness of EE programs is a critical to deciding which programs to offer, and represents the seventh step of the EE program process, as illustrated in Figure 10-1. [64]

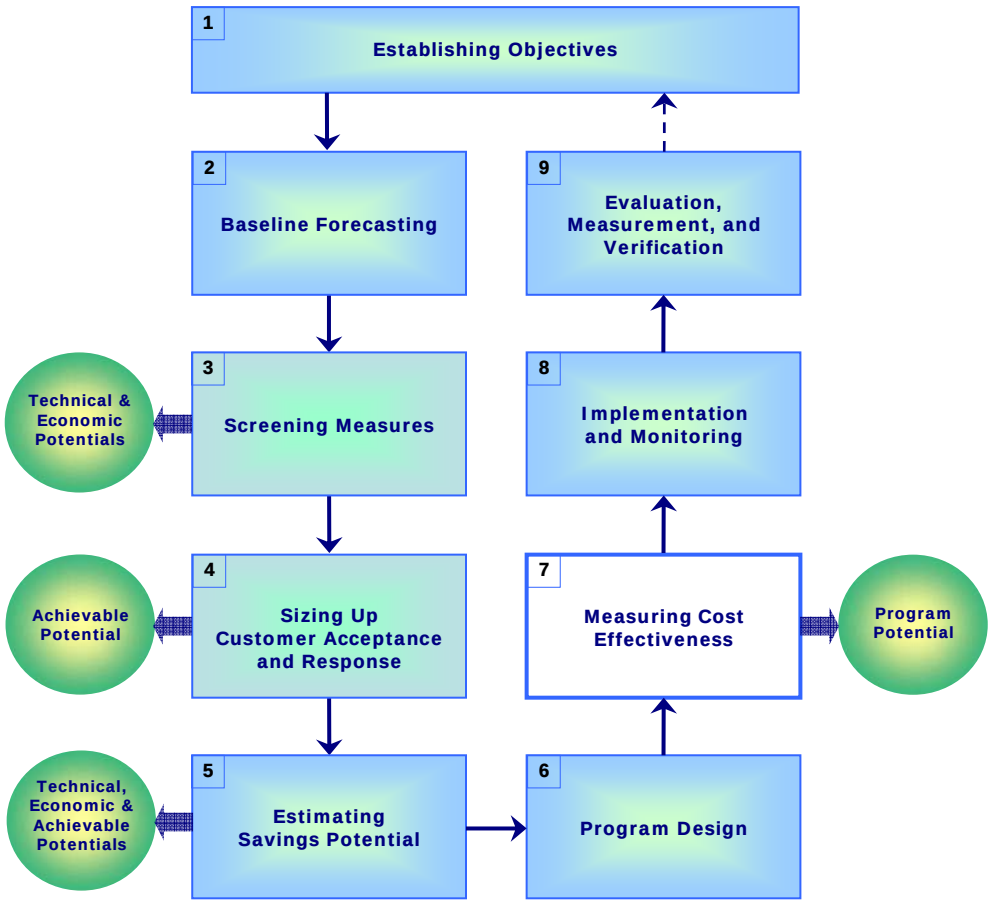


Figure 10-1
EE Program Process, Step 7: Measuring Cost-Effectiveness

[64] In the context of this document, "EE" refers to both energy efficiency/conservation and demand response.

As briefly described in Chapter 3, five economic tests are widely used to assess the cost-effectiveness of EE programs. These tests are often referred to as the "standard practice" tests because they are based on the California Standard Practice Manual.[65] These tests are intended to answer whether a program cost effective and from whose point of view, since EE programs impact stakeholder groups differently, be they customer segments—general ratepayers vs. program participants—the utility, or society at large. This chapter describes each of the five "standard practice" tests and the inputs for each.

Test Perspective

1. The participant test addresses the participant's perspective: "Are participants better off as a result of the program?"

The total resource cost (TRC) test addresses the perspective of the utilities and the ratepayers: "Does the total resource cost go down?"

The ratepayer impact (RIM) test addresses the utility's rates perspective, "Will rates increase as a result of the program?"

The utility cost test addresses the utility's total cost perspective: "Are revenue requirements lower as a result of the program?"

The societal test addresses society as a whole, "Will societal costs go down as a result of the program?"

As shown in Table 10-1, the specific benefits and costs that are included vary by test.

[65] California Standard Practice Manual: Economic Analysis of Demand Side Programs and Projects, July 2002. http://drrc.lbl.gov/pubs/CA-SPManual-7-02.pdf

Table 10-1
Benefits and Costs in the Five Standard Practice Tests

Test	Benefits	Costs
Participant Test	Participant bill reductions	Participant bill increases
	Incentive payments to participants	Program costs paid by participant (investment,operating)
	Tax credits	Fees paid to utility by participant
Total Resource Cost (TRC) Test	Utility avoided energy costs	Energy and capacity costs
	Utility avoided capacity costs	Utility rate-based investment
	Utility avoided distribution costs	Program costs paid by utility (operating, marketing)
	Utility avoided transmission costs	Program costs paid by participant (investment,operating)
	Tax credits	
Ratepayer Impact (RIM) Test	Utility avoided energy costs	Energy and capacity costs
	Utility avoided capacity costs	Utility rate-based investment
	Utility avoided distribution costs	Program costs paid by utility (operating, marketing)
	Utility avoided transmission costs	
	Revenue gains	Revenue losses
	Fees paid to utility by participant	Incentives paid to participants
Utility Cost Test	Utility avoided energy costs	Energy and capacity costs
	Utility avoided capacity costs	Utility rate-based investment
	Utility avoided distribution costs	Program costs paid by utility (operating, marketing)
	Utility avoided transmission costs	
	Fees paid to utility by participant	Incentive payments to participants
Societal Cost Test	Utility avoided energy costs	Energy and capacity costs
	Utility avoided capacity costs	Utility rate-based investment
	Utility avoided distribution costs	Program costs paid by utility (operating, marketing)
	Utility avoided transmission costs	Program costs paid by participant (investment,operating)
	Externality benefits	Externality costs

Test Results

For each of the tests, the discounted stream of program benefits is compared to the discounted stream of program costs over the life of the program. The program is deemed to be cost effective:

- If the net present value (NPV) of the discounted stream of benefits minus the discounted stream of costs over the life of the program is greater than or equal to zero; or
- If the benefit-cost ratio (i.e., the discounted stream of benefits divided by the discounted stream of costs) is greater than or equal to 1.0.

The levelized cost (per kW installed or per kWh) is also sometimes calculated to compare the EE resource to supply-side resources.[66]

Although these tests were originally developed in the 1980s, they remain essentially unchanged and are in wide use today. Two additional factors, however, warrant discussion: (a) environmental benefits should be explicitly included in both the societal test and the total

[66] The levelized annual cost per kWh of an EE program, for example, is the levelized annual discounted payment amount for each year in the life of the program divided by the annual kWh saved.

resource cost test; and (b) the issue of consumer surplus, which represents the difference between the "value" that customers derive from consuming a product and the amount they actually pay for it.[67]

Issues with the Standard "DSM" Cost-effectiveness Tests

In general, there is no "right" test because each test measures cost-effectiveness from a distinct perspective. The test most widely used today is the total resource cost (TRC) test, while only a few utilities still use the RIM test. Some utilities use a combination of tests.

- The participant test measures the benefits and costs of an EE program to the participant and does not consider the impact on the utility. This test is an indicator of the attractiveness of the program to the customer.
- The RIM test measures the benefits and costs to the utility and does not consider the impact to the participant. This test evaluates the EE program from the point of view of rates. It is also referred to as the "non participant" or "no losers" test.
- The TRC test includes all of the costs and benefits to the utility and its ratepayers as a whole. This test measures the change in the average cost of energy services to utility customers. In other words, is it cheaper to meet energy needs by saving a kWh or by supplying the kWh from a power plant. The TRC test is sometimes referred to as the "all ratepayers" test. Dollar amounts that flow between the utility and the ratepayers are ignored since they are simply transfer payments. The TRC test combines all of the benefits and costs from the participant test and the RIM test. Hence, it is the sum of these two tests.
- The utility cost test measures the net costs to the utility as a result of the EE program. This test measures the change in revenue requirements. Since total costs to the utility (i.e., revenue requirements) are equal to total revenues (i.e., total energy bills paid), this test also measures the change in total energy bills paid. The only difference between the utility cost test and the RIM test is that the utility cost test does not include revenue gains or losses.
- The societal test includes all of the costs and benefits to the utility and its ratepayers as a whole including externalities. This test measures the change in the total cost of energy services to a utility customer. The only difference between the societal test and the TRC test is that the societal test does not include externalities.

Which is the Right Test?

There is no easy answer to this question. Each utility must make its own determination, recognizing the trade-offs involved in any such comparison. The following rules of thumb are widely used in the profession:

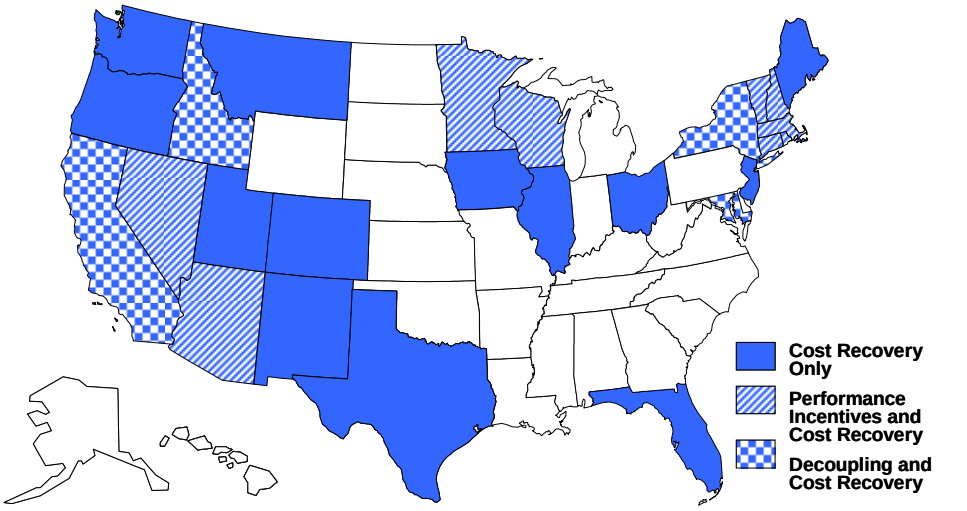
- EE programs that pass the RIM test should be implemented because they are cheaper than the supply side alternative, rates will go down, and such programs will benefit all customers.
- EE programs the fail the TRC test should be eliminated because they are more expensive than the supply side alternative.

[67] Another way to think about this is that a consumer's willingness to pay for a product (or service) will always be greater than or equal to its price.

- EE programs that pass the TRC test but fail the RIM test (i.e., the TRC net benefits are positive but the RIM net benefits are negative) are not so straightforward because non-participants will experience bill increases. However, if all customers participate in an EE program that passes the TRC test, the average cost of energy services will go down and all customers' cost of energy services will go down (even though rates may increase).[68]

Impact of EE Performance Incentive Mechanisms on Cost Effectiveness Tests

As discussed in Chapters 2 and 4, EE program cost recovery and lost revenue recovery are the two mechanisms that remove the "disincentives" for utilities to invest in EE. The cost effectiveness tests assume that the utility will recover its costs and that its rates will be adjusted for changes in revenues so these mechanism do not affect the tests. However, the performance incentive mechanism which provides an "incentive" for utilities to invest in EE will affect all of the tests except the participant test. This type of incentive will increase revenue requirements and is therefore a cost in the TRC, RIM, utility cost, and societal tests. As shown in Figure 10-2, several states currently have performance incentives for EE programs. For these states, the cost of the performance incentives should not be ignored.



Source: Martin Kushler, Dan York and Patti Witte, "Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives," October 2006, ACEEE Report Number U061. Includes additional information to reflect recent regulatory changes.

Figure 10-2
Status of Utility Regulatory Mechanisms for EE Programs in 25 States

[68] A. Faruqui and J. Chamberlin, "Principles and Practices of Demand-Side Management." EPRI Final Report, TR-1025556. August 1993.

Additional Adjustments to the Cost-Effectiveness Tests

As mentioned earlier, two additional factors need to be considered in the cost effectiveness tests: environmental externalities—in particular, carbon emissions—and consumer surplus (CS). CS is the difference between the "value" that consumers derive from a product and the price that they pay for it. Accounting for CS is particularly important for DR programs. Each of these is discussed below.

Environmental Benefits and Costs

Increasing concerns over the need to mitigate climate change and the cost to the utility industry of state and federal climate change legislation have led the utility industry and policy makers to actively seek alternatives to the combustion of fossil fuels to produce electricity. Both energy efficiency programs and renewable energy are regarded as key resources to help utilities reduce carbon emissions. Energy efficiency is of particular importance in the short term because many programs are more cost-effective than renewable energy sources. In addition, about half of the states in the U.S. now have renewable portfolio standards in place. This number is expected to rise. In some states, energy efficiency is included as a resource in meeting renewable portfolio standards (RPS).[69]

It is important to recognize that, although energy efficiency programs that reduce energy usage will result in lower carbon emissions, other emissions such as NOx and SOx may increase as a result of a program because it may delay the replacement of inefficient, polluting power plants. This is very specific to the individual utility and the supply mix. Likewise, demand response (DR) programs that shift energy usage are unlikely to reduce carbon emissions and may actually increase carbon as more energy is produced from base load plants. Each utility must determine the specific environmental impact of an EE program or group of programs. Of particular importance in today's policy environment is the impact of EE on carbon emissions.

At a minimum, the costs and benefits of environmental externalities, such as carbon and other emissions, should be included in the assessment of EE programs in the societal test and possibly the TRC test. It is only a matter of time before federal climate change legislation, such as a carbon tax or cap-and-trade market, is implemented. At that point, the benefit to the utility of EE in reducing carbon emissions should also be included in the TRC test.

Consumer Surplus

Under current regulatory practice, cost-effectiveness analyses of DR programs are based on the standard cost-effectiveness tests. These tests do not account for either the loss in consumer welfare that occurs when consumers reduce peak period usage or the gain in consumer welfare resulting from increased off-peak usage. To assess the magnitude of this bias in the participant test, it is useful to examine the concept of consumer surplus (CS). CS is defined as the difference

[69] In states where EC is included as a resource in meeting RPS, although an EC program may not be cost effective based on the standard practice manual tests, it may be a lower cost alternative to traditional renewable energy sources.

between the value consumers derive from consumption and the amount they actually pay for that consumption.

The value consumers derive from consumption, or the consumer's willingness to pay, equals the sum of the marginal utilities of the various units consumed. For a normal good, the marginal utility declines with additional units consumed, and is reflected in the familiar downward sloping shape of the demand curve. When the price of a commodity goes up, CS shrinks; likewise, when the price goes down, CS expands.

The standard cost-effectiveness tests use changes in the consumer's bill to measure changes in consumer welfare. These tests were developed this way for two reasons. First, when the tests were developed, there was concern that regulators and other policy makers would not put much faith in estimated price elasticities, which are needed to estimate CS. Second, when the tests were developed, most of the EE programs were energy conservation or load management programs, not rate programs. Hence, the price of electricity was held constant and changes in the quantity of electricity consumed were determined exogenously, often based on engineering rules of thumb. Typically, electricity usage was reduced in proportion to the efficiency change between the old technology and the new technology.

However, for rate programs, such as a time-of-use (TOU) rate or a critical peak price (CPP), price elasticities are necessary to predict the new electricity consumption that results from the new prices. Specifically, since we know the price change and the original electricity consumption, price elasticities are used to predict the electricity consumption under the new rate. Thus, bill changes can be estimated and we have the information needed to calculate CS. For example, TOU rates raise prices during the peak period and lower them during the off-peak period. Higher prices during the peak period result in lower consumption, and "consumer sacrifice;" lower prices during the off-peak period raise consumption, and result in "consumer gain." It is an empirical question whether the gain is greater than the sacrifice.

Based on our discussion of performance incentives, environmental benefits and costs, and consumer surplus, Table 10-2 shows proposed modifications to the standard cost-effectiveness tests.

Table 10-2
Suggested Modifications to Standard Practice Tests (Highlighted)

Test	Benefits	Costs
Participant Test	Participant bill reductions or CS	Paticipant bill increases or CS
	Incentive payments to participants	Program costs paid by participant (investment,operating)
	Tax credits	Fees paid to utility by participant
Total Resource Cost (TRC) Test	Utility avoided energy costs	Energy and capacity costs
	Utility avoided capacity costs	Utility rate-based investment
	Utility avoided distribution costs	Program costs paid by utility (operating, marketing)
	Utility avoided tranmission costs	Program costs paid by participant (investment,operating)
	Tax credits	Utility performance incentive
Ratepayer Impact (RIM) Test	Utility avoided energy costs	Energy and capacity costs
	Utility avoided capacity costs	Utility rate-based investment
	Utility avoided distribution costs	Program costs paid by utility (operating, marketing)
	Utility avoided transmission costs	
	Revenue gains	Revenue losses
	Fees paid to utility by participant	Incentives paid to participants
	Environmental emissions benefits	Environmental emissions costs
		Utility performance incentive
Utility Cost Test	Utility avoided energy costs	Energy and capacity costs
	Utility avoided capacity costs	Utility rate-based investment
	Utility avoided distribution costs	Program costs paid by utility (operating, marketing)
	Utility avoided transmission costs	
	Fees paid to utility by participant	Incentive payments to participants
		Utility performance incentive
Societal Cost Test	Utility avoided energy costs	Energy and capacity costs
	Utility avoided capacity costs	Utility rate-based investment
	Utility avoided distribution costs	Program costs paid by utility (operating, marketing)
	Utility avoided transmission costs	Program costs paid by participant (investment,operating)
	Environmental emissions benefits	Environmental emissions costs
		Utility performance incentive

Bill Savings and Consumer Surplus. Table 10-3 shows example calculations of consumer surplus (CS) for a TOU program for different price elasticities and peak usage amounts, illustrated the strong relationship between bill savings and consumer surplus for revenue-neutral rates.[70] For two-period TOU rates that are revenue-neutral, the general result is that bill savings are *twice* as large as consumer surplus.

Assume that a customer consumes 1,000 kWh per month and faces a flat rate of 5 cents/kWh. She later moves to a revenue-neutral TOU rate with a peak price of $0.07 per kWh and an off-peak price of $0.03 per kWh. Her original monthly bill is $50 and her new bill, with unchanged usage values, is also $50. Thus, the TOU is revenue-neutral. The results are summarized in Table 10-3 under a variety of assumptions about the peak usage share of monthly usage and about the price elasticity of demand in the peak and off-peak periods.[71] In all cases, changes in CS are positive, indicating that welfare is improved by shifting to TOU rates, i.e., consumers gain more by increasing off-peak usage than they lose by reducing peak usage.

[70] For more information on electricity price elasticity consult: *Price Elasticity of Demand for Electricity: A Primer and Synthesis*. EPRI. Palo Alto, CA: 1016264. 2008.
[71] These ranges reflect percentages of use when the peak TOU period is defined as 4 to 6 hours during weekdays.

Table 10-3
Bill Savings and Consumer Surplus ($ per month)

Peak Share of Monthly Usage (%)	Variable	Price Elasticity of Demand			
		-0.1	**-0.2**	**-0.5**	**-1.0**
10%	Bill Savings ($)	7.2	14.4	36	72
	Consumer Surplus ($)	3.6	7.2	18	36
30%	Bill Savings ($)	1.05	2.1	5.25	10.5
	Consumer Surplus ($)	0.525	1.05	2.625	5.25
50%	Bill Savings ($)	0.8	1.60	4.0	8.0
	Consumer Surplus ($)	0.4	0.8	2.0	4.0

Note that the estimated value of CS is exactly *half* the value of bill savings. This general result holds for a wide variety of cases with linear demand, revenue-neutral TOU rates, equal peak and off-peak elasticities, and zero cross-price elasticities. For simplicity in this example, we assumed the incremental cost of TOU metering to be zero. If metering costs are included, both bill savings and consumer surplus decline by the amount of these costs.

Economic Surplus. The economic welfare tests include the producer surplus test and the economic surplus test. Producer surplus (PS) is the difference between the total revenue from producing a certain amount of electricity and the cost incurred in producing those units. Graphically, it constitutes the triangular area below the price line and to the left of the marginal cost curve. Economic surplus (ES) is the sum of the CS and PS. In a competitive market, price equals marginal cost; at that point ES is maximized. The value that customers derive from consuming the last unit is exactly equal to the marginal cost of producing that unit. Economic efficiency is maximized. Any other price would reduce welfare, and this constitutes one of the central theorems of welfare economics. Thus, from the perspective of welfare economics, the objective is to maximize ES, which will not often yield the same policy conclusions as maximizing either the TRC or RIM tests. In the real world, and especially in the world of electricity, prices are rarely based on marginal costs. Under cost-of-service regulation, prices are often set equal to average costs. Thus, they exceed marginal costs during the off-peak periods and are below marginal costs during the on-peak periods. There is a potential for improving economic efficiency by raising prices during the on-peak period and lowering them during the off-peak period, so that they better approximate the marginal costs of electricity. The new prices need to reflect both marginal energy and marginal capacity costs.

A shift to TOU pricing would improve economic efficiency in the aggregate (i.e., for all customers) if it raises ES. However, even if ES rises in the aggregate, some customers may be made worse off. This should not prevent that policy from being implemented, according to the

Kaldor-Hicks criterion in welfare economics.[72] This argues that if the gainers from a public policy can compensate the losers, that policy is worth doing. The Kaldor-Hicks criterion allows a wider variety of policies to be considered than the more restrictive Pareto criterion, which would only allow such policies to be undertaken that made no one worse off, and made at least one person better off.

A simple example of the relationship between the cost-effectiveness tests and economic surplus is provided below. This example continues the discussion of the previous consumer who uses 1,000 kWh per month. She is assumed to use 500 kWh in the peak period and 500 kWh in the off-peak period. The flat rate and TOU rates are as discussed earlier and the price elasticity of demand in both periods is -0.50. For simplicity, assume that the marginal cost curve is constant at $0.05 per kWh. This assumption is often made when evaluating demand-side programs since they do not change the demand-supply balance sufficiently to change the value of marginal costs. The following definitions are used in measuring the different welfare impacts:

- Bill Savings = Old Bill—New Bill = P x Q - P' x Q' = Participant Test Benefits = Revenue Loss (which is considered a cost under RIM but disregarded under TRC, since it is a transfer payment between participants and non-participants), where the primes denote new values associated with TOU pricing; this formula is applied individually to peak and off-peak periods and the results are added to obtain a monthly value.
- TRC = Total Resource Cost = Delta Q x MC, and it is similarly computed as the sum of peak and off-peak values.
- RIM = Ratepayer Impact Measure = TRC—Bill Savings = Producer Surplus (defined below).
- Delta CS = difference between the value that accrues to consumers when they consume a given quantity and the amount they spend in order to consume it. For the peak period, it is the sum of the area of the rectangle bounded by the new and old price at the new quantity and the triangle with height equal to Delta P and base equal to Delta Q.
- Delta PS = difference between revenues that accrue to producers from selling a given quantity and their cost in producing it.
- Delta ES = Delta CS + Delta PS

The results are summarized in Table 10-4, which shows that as prices rise in the peak period customers experience a negative bill impact of $300. The opposite occurs in the off-peak period, where the bill falls by $700. The total bill for the month falls by $400. This is the customer's bill savings and represents her benefits under the Participant Test. Marginal costs fall by $700 in the peak period and rises by $300 during the off-peak period, yielding a net value of $400 in avoided costs. This is the value of the TRC test since there are no administrative program costs or metering costs in the example. The RIM test is the sum of the TRC values and revenue losses (i.e., negative bill savings) and computes to zero. The change in consumer surplus is $200, which is again half of the amount of bill savings. The change in producer surplus is zero and the economic surplus, equal to the sum of consumer surplus and producer surplus, is $200. In this example, the TRC test is $400, and suggests that the program should be implemented. The economic surplus test is also positive but half the size of the TRC test.

[72] See, for example, the discussion in Ch. 16 of William J. Baumol, 1965, *Economic Theory and Operations Analysis*, 2nd ed, Englewood Cliffs, NJ: Prentice Hall, 1965.

Table 10-4
Quantifying Net Benefits ($ per month)

Row	Variable	Time Period		
		Peak	Off-Peak	Monthly
(1)	Bill Savings (participant)	-300	+700	+400
(2)	Avoided costs (TRC)	+700	-300	+400
(3) = (2) – (1)	Impact on rates (RIM)	+1000	-1000	0
(4)	Consumer surplus (CS)	-900	+1100	+200
(5)	Producer surplus	+1000	-1000	0
(6) = (4) + (5)	Economic surplus	+100	+100	+200

Economic Variables for Cost-Effectiveness Analysis

Computing either the net present value (NPV) of an EE program or the benefit-cost ratio requires estimating the present value of the stream of costs and benefits of the program over its life. This requires estimates of both escalation (or inflation) rates and discount rates.

Escalation Rates

To estimate the future annual costs and benefits of an EE program, the value of each component of the cost-effectiveness test must be appropriately escalated over time. In general, escalation rates reflect expected inflation for each of the cost and benefit components. However, different inflation indexes may be appropriate for different cost categories. For example, a GNP price index may be the appropriate escalation rate for program incentive payments, a materials index may be appropriate for capital costs, and a labor index may be appropriate for program operating costs. Regardless of the specific index used, it is important to understand that the incentive levels, utility costs, and participant costs will increase over time due to inflation.

Discount Rates

In the past, some have argued that different discount rates should be applied to different tests. However, since each test comprises multiple components and many of these components appear in multiple tests, it seems more appropriate to use the appropriate discount rate for each component of the cost-effectiveness test. Similar to the escalation rate, the most important

distinction is that the discount rate for operating and marketing costs may not be the same as the discount rate for capital costs. For example, for the utility's avoided energy costs or avoided capacity costs, the utility's allowed rate of return for capital investments is the appropriate discount rate. However, for the utility's marketing costs or incentive payments to participants which are operating (not capital) costs, the cost of paying off a loan may be the appropriate discount rate. The appropriate discount rate or rates to use is specific to each utility.

Utility Cost Variables for Cost-Effectiveness Analysis

In this section, we discuss the utility cost variables that vary with the level of electricity supplied. These include capacity costs, energy costs, transmission costs, and distribution costs. How these costs change will depend on the particular EE program. For example, for an EC program, we expect avoided energy costs to comprise the major component of benefits to the utility. However, for a DR program, we expect avoided capacity costs to comprise the major component of benefits to the utility

Generation Capacity Costs

Generation capacity costs are a measure of the cost of building and maintaining new generation plants. Capacity cost is determined differently in a restructured market than for a vertically integrated utility. In today's restructured markets, capacity prices are typically determined in an auction setting. In these cases, the capacity price is based on a bidding process and is set for the market for a specified period of time such as 6 months or one year. These costs can vary significantly in capacity constrained areas. For example, in a recent PJM auction, the capacity price changed from $62 per MW-day for the first part of 2007 to $140 per MW-day for the latter part of 2007. For a vertically integrated utility, the utility will typically identify the type of plant that will be added to its planned capacity additions. In many cases, this is a combustion turbine gas plant (called a CT). A typical capacity price for a CT is $52 per kW-year. These costs represent the marginal cost of capacity at the generation level. As mentioned earlier, for DR programs, avoided capacity costs will typically comprise the majority of the total benefits to the utility.

Energy Costs

Wholesale energy costs vary hourly with the level of kWh produced. In restructured markets with independent system operators (ISOs), some jurisdictions (such as PJM and the NYISO) use locational marginal pricing (LMPs). LMPs are determined based on the prices offered by generators, the prices bid by dispatchable loads (if any), and the transmission constraints. LMPs vary by location (or bus) on the grid and represent the marginal cost to supply one more MW of load at a given location.

The cost effectiveness tests require a future stream of energy prices. Typically energy prices or LMPs are forecast on an hourly basis using a production costing model that simulates the day-to-day operation of a utility system or a larger system (if the market is restructured) including projected fuel costs, variable expenses, maintenance schedules, and other factors.

For energy efficiency programs, avoided energy costs will typically comprise a large percentage of the total benefits to the utility. It is important to note that, in restructured markets, where distribution companies have entered into contracts for power (e.g., full requirements contracts), although the wholesale energy cost is avoided as a result of an energy efficiency program, the actual benefit may be split between the distribution company and the supplier (depending on the terms of the contract that the distribution company or LSE has with the supplier). Hence, the avoided energy costs may not be fully realized by the utility.

Transmission Capacity Costs

Marginal transmission capacity costs are the additional costs incurred for an increment of peak load. These values are typically calculated based on historical transmission investment data and are very system specific. Transmission investments occur for a variety of reasons; only a portion is related to growth in peak demand. The marginal transmission cost should be based on investments related to growth in system peak. These costs are only relevant for vertically integrated utilities and are typically small compared to generation capacity and energy costs.

Distribution Capacity Costs

The marginal distribution costs that are relevant for EE programs are the increased distribution costs to provide an additional kW of capacity at the time of the distribution system's peak demand. Costs related to connecting another customer to the distribution system are not relevant. These values are typically calculated based on historical distribution investment data and are very system specific. Very large customers who are served at the transmission system voltage level will have no relevant distribution costs. Like transmission costs, these costs are small relative to generation capacity and energy costs.

Summary and Resources

The five standard practice cost-effectiveness tests for EE programs each represent the perspectives of distinct stakeholders, including general ratepayers, program participants, the utility, society at-large, and combinations thereof. States vary in their requirements, but most allow utilities to apply multiple tests, with the total resource cost (TRC) currently the most prevalent. EE programs that pass the RIM test should generally be implemented because they are cheaper than the supply side alternative, and conversely, EE programs the fail the TRC test should generally be eliminated because they are more expensive than the supply side alternative. EE programs that pass the TRC test but fail the RIM test are not so straightforward because non-participants will experience bill increases. However, if all customers participate in an EE program that passes the TRC test, the average cost of energy services will go down and all customers' cost of energy services will go down, even though rates may increase.

The standard practice tests do not account for carbon offset value nor consumer surplus; this chapter presents considerations for revisited the tests in this context.

Resources

California Standard Practice Manual: Economic Analysis of Demand Side Programs and Projects, July 2002. http://drrc.lbl.gov/pubs/CA-SPManual-7-02.pdf

Economic Theory and Operations Analysis, William J. Baumol, 1965. 2nd ed, Englewood Cliffs, NJ: Prentice Hall, 1965.

Principles and Practices of Demand-Side Management. A. Faruqui and J. Chamberlin. EPRI. Palo Alto, CA: TR-1025556. 1993.

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11
IMPLEMENTATION AND MONITORING

Introduction

Implementation and monitoring is the next step in the EE program process illustrated in Figure 11-1.[73]

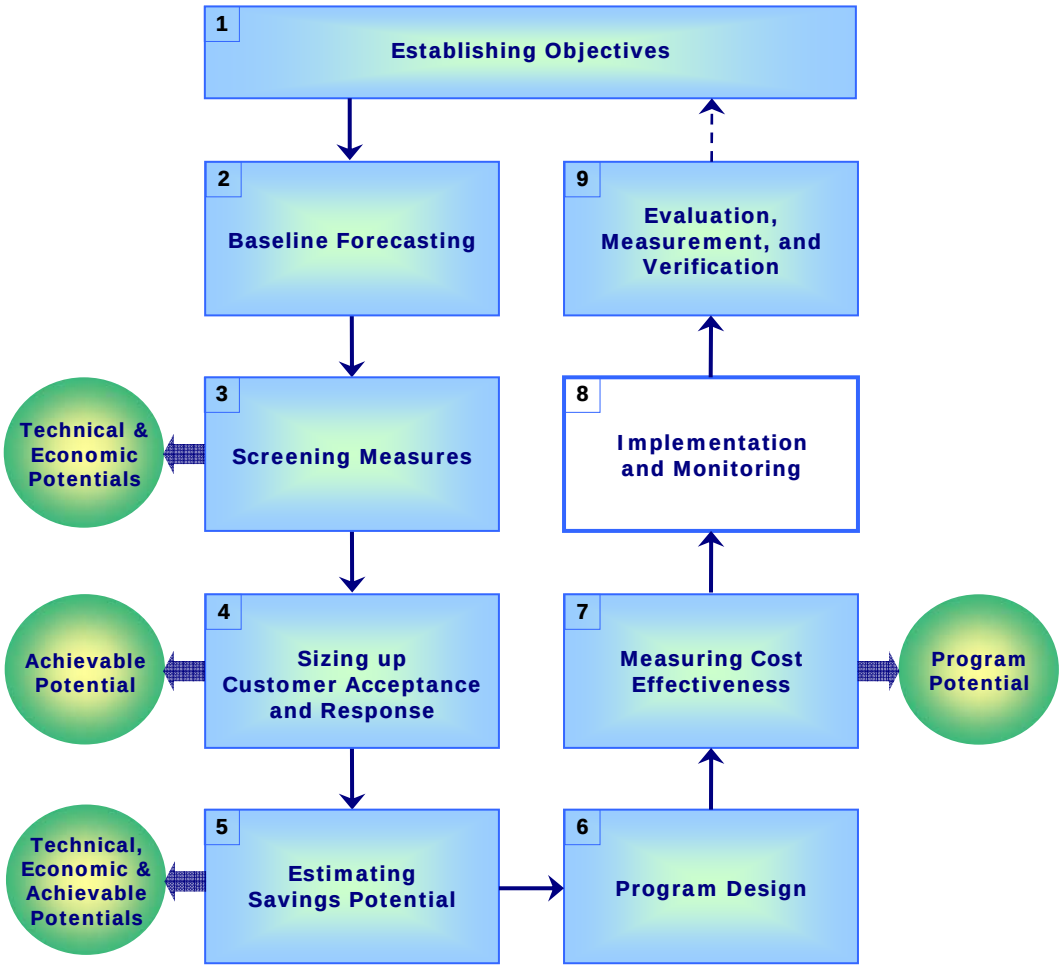


Figure 11-1
EE Program Process, Step 8: Implementation and Monitoring

[73] In the context of this document, "EE" refers to both energy efficiency/conservation and demand response..

In this step, "perfectly designed" programs are put to the test of whether or not they are accepted by customers. The EE program implementation manager knows the objective, the plan, and the means with which he or she will launch the program delivery. What remains to be determined is how well the planning and design estimates for participation, impacts, and costs match the program's achievements in the marketplace. Monitoring answers this question and indicates any shortcomings in the program design or delivery structure.

The monitoring function develops information that has two uses: (1) fine tune program implementation activities in a real-time basis, when program implementation is actually happening, and (2) generate the data required in the next step of the EE program process (i.e. evaluation).

This chapter deals with the following topics related to program implementation and monitoring: getting started, assessing resource needs, organizational implications, implementation issues, and activities and monitoring. The chapter also identifies the issues faced by the program implementer, reviews factors that are critical to the successful delivery of EE programs, and offers examples of solutions.

Several key EPRI reports provide further details on implementation and monitoring. The "Demand-Side Implementation Guide" (TR-100349) uses nine utility case studies to discuss ways of approaching five major implementation activities (planning, acquiring resources, developing administrative support, developing market strategy, and program delivery). "DSM Program Monitoring" (EM-5706) discusses issues and recommendations for successful monitoring of DSM programs. "A Guide to Annual Marketing Planning" (EM-6087) offers step-by-step guidelines for planning marketing-related DSM activities.

Getting Started

Gaining Organizational Experience with Pilot Program Implementation

The success of an EE program hinges on a utility's ability to effectively market and administer programs that produce the desired impacts at reasonable costs. Most utilities start with a small number of pilot programs to help the organization develop the knowledge and skill associated with implementing the programs. These pilot programs build organizational capability and permit testing, the utility's planning estimates for impacts, customer participation, and costs. They also create the opportunity to modify program designs and features.

By keeping a program on a pilot scale, the utility can learn more about "what works" without committing to high levels of visibility or expenditures. Pilot programs also provide the ability to conduct early evaluations of program impacts that reflect local market conditions and energy-utilization patterns. This increases the accuracy of the expected impacts and also provides a "trial run" with the planned evaluation techniques, data-collection procedures, and analysis methods.

When to Implement Pilot Programs versus Full-Scale Programs

Pilots can be especially valuable corporate learning aids for utilities with limited experience in program implementation or with traditional marketing activities involving trade allies (e.g., manufacturers, distributors, designers, builders, and contractors). A pilot program can help these utilities establish critical relationships with these trade allies.

Proceeding directly to full-scale program implementation is warranted when:

- The program is a refinement of an existing EE program;
- The program is similar to those previously offered by many utilities;
- The utility has prior experience in designing and running EE programs for its market or customer base;
- Significant lost opportunities would occur during the pilot phase; or
- The utility urgently needs the EE resources and the expected value of the resource gained exceeds any additional cost from unproven program features.

A utility's transition into full-scale implementation of EE programs brings with it much in the way of learning about customers, markets, and challenges to the utility organization's internal operation and coordination. It is common for a utility to offer an initial set of programs that are fairly straightforward to administer and involve commonly known technologies. Over a period of years, the utility typically evolves its portfolio of EE programs to encompass less common or more complex technologies and systems, greater differentiation of marketing approaches to customer segments, and specialized program features and delivery techniques that appeal to more specialized audiences. Successful EE programs are not static and remain highly responsive to market conditions.

Assessing Resources Needed: People, Funding, and Market Cooperation

Implementation requires knowledgeable people, fund, and often the cooperation of equipment vendors and service firms. There are many differences between EE program implementation and the construction of supply-side resources: EE programs are more labor-intensive; EE program funding is typically an operating expense rather than a capital investment; information needs include predicting human behavior as well as technology performance; and equipment is generally ordered by customers or their suppliers and then delivered and installed on customer premises, rather than being ordered by the utility and delivered to the supply-side construction site.

People

EE program implementation needs a variety of labor skills, including marketing, engineering, financial analysis, customer service, building technologies and design, computer-aided analysis, and administrative functions such as activity tracking and incentive payment processing. People with these skills must all work together as a team—regardless of whether they reside in

specialized functional departments and are recruited as needed by EE program managers or whether they have been organized into an EE implementation or marketing services department.

The number of staff members in an EE program organization may be as few as one or as many as several hundred. The staff size reflects the size of the utility, the number of programs offered, and the organization's preferences for using utility personnel or contract labor to execute the programs.

One trait that distinguishes successful EE program staffs is an entrepreneurial sense of marketing products and services. Implementing EE programs requires a broad sense of marketing beyond what is needed for a simple sales assignment. It entails providing a desired service or product to an appropriate customer group in a manner that ensures that customers will use the product or service, so as to produce desired changes in loads consistent with a utility's EE program objectives. Later sections in this chapter discuss issues with program staffing, including considerations between existing or newly hired staff and key aspects of recruiting and orientation.

Funding

U.S. utilities are spending billions of dollars per year on EE programs, involving from tens to hundreds of utility employees and contractors. Typical ranges of EE program budgets are shown below:

- Smaller utility or initial EE program: $2-5 million/year;
- Medium-sized utility with full EE programs: $10-40 million/year; and
- Large utility or aggressive EE programs: $50-200+ million/year

The vast majority of expenditures—perhaps as much as 75%--is provided as financial incentives to customers to encourage their purchase of energy-efficient equipment or their participation in the programs. Other expenditures are for utility staff labor and marketing, contracted program service providers (to whom certain functions such as administration of energy audits, incentive processing, impact evaluation, etc. may be outsourced, where appropriate), and suppliers of utility communication and load control systems.

Trade-Ally Cooperation

As noted in Chapter 9, many utilities involve trade allies in program implementation to expand the adoption of EE programs by customers. Trade allies can include manufacturers, suppliers, distributors, designers, architects, and building service firms such as electrical and mechanical contractors. It is vital for utilities to engage the cooperation of these trade allies in program implementation. This cooperation should help minimize the level of additional utility effort (people, funding, and organizational support) needed to sustain the energy savings and load reduction targeted by each utility's EE programs.

Effective marketing of most EE programs requires individual customers to purchase, install, or otherwise accept EE measures. Choosing the form of personal marketing tactics involves striking a balance between using utility personnel or contract labor to make direct contact with customers. Utilities need to consider the cost trade-offs of executing the program marketing function in-house versus providing training and support to suppliers and other trade allies who in turn make direct contact with end-use customers. There are advantages and disadvantages to each approach, and the appropriate selection depends on the utility's EE program objectives.

For example, if a utility chooses to market its EE programs directly and maintain close contact with its customers, the utility will likely experience higher marketing and program delivery costs because it must replicate some of the market infrastructure already in place. These costs may be acceptable if the implementation plan ensures a high participation rate among customers (who otherwise would not have taken the desired actions) and can better target those customers with the most promising characteristics.

Alternatively, a utility may prefer to leverage the talent and marketing infrastructure offered by trade allies and deliver a program through market mechanisms. This approach may result in lower marketing and delivery costs, can capitalize on the "presence" of the market companies in the field every day of the week, may ensure more diversified promotional strategies, and may garner a wider array of participating customers. Using this approach also promises to cut substantially promotional and staff labor costs. However, this method may have disadvantages:

- Vendors may be selective in their own promotion, perhaps only mentioning a rebate on certain pieces of equipment to their largest or best customers or anticipating that only sophisticated customers would request rebates. However, these same customers may already be purchasing the equipment promoted by the utility EE program, and their purchases with rebates might not result in any change in energy use.
- Vendors could also over-promote a program, with the resulting deluge of interested customers depleting inventories of equipment or creating backlogs in processing program participants, which could result in customer dissatisfaction.
- If a technology promotion program requires site-specific calculations to document the anticipated electric demand or energy savings (in order to determine a rebate payment), vendors can provide customers with valuable assistance to accurately complete the paperwork. However, this can be a problem if the vendor's staff are not well-trained or skilled in the calculations or verification required. In this case, a utility may annoy the customer with requests for further information or clarification on rebate applications. A worse case would be a customer feeling misled to purchase and install equipment that was ineligible for a utility rebate, which would place the utility in a difficult position.

Organizational Implications

EE program implementation frequently brings significant changes to the way a utility does business with its customers. It often involves complex sets of activities and personnel, and an alteration of the organizational structure with the addition of a new department. Careful attention needs to be given to the shape and placement of the EE program implementation organization. Years of utilities' experiences reveals several critical requirements:

- Implementation requires a marketing organization with "savvy" about technologies, customers, and how the market works;
- The organization needs both the responsibility and the authority to accomplish its mission;
- Executive levels of management must demonstrate early and continuing interest in the success of the EE program effort and a commitment of the needed resources; and
- Flexibility—in budgets, staffing, scheduling, and tactics—is paramount

A Marketing Organization with "Savvy"

Effective energy efficiency program implementation requires a marketing-oriented organization with savvy about the resource planning objectives and economics that dictate acceptable EE program costs and accomplishments. This savvy pertains to how the organization and its personnel think about market opportunities to secure cost-effective EE impacts. Program staff must consider how an EE technology or measure will affect energy use and peak demand of different types of customers, assess the degrees of difficulty associated with soliciting a customer to participate in an appropriate program, and conclude whether the expected impacts will be significant and cost-effective.

In contrast with the sales approach employed in the past, where utilities tried to sell what they produced without regard for customers' needs, the marketing orientation begins with customers' needs in mind and requires a long-term view of the utility-customer relationship. EE program marketing connects a utility with its customers to secure both initial customer participation and to maintain customer involvement over periods of years. EE program implementation relies heavily on traditional marketing techniques: identifying and assessing target markets, profiling target customer segments, developing marketing strategies to reach customers, creating marketing materials, tracking customer response and satisfaction, and evaluating the effectiveness of different marketing strategies.

This orientation sets the stage to move the implementing organization toward a result-based performance system. Older style accountability systems measured activities, such as the number of customer energy audits performed or the number of rebated applications processed. A savvy marketing system demands staff focus on performance indicators, e.g., EE impacts—MW or MWh "saved" as a result of actions completed by customers. This form of accountability rewards program staff for displaying flexibility in achieving the utility's planning objectives and provides feedback to program design decisions. It also permits executive management to stress EE program staff's contribution to the utility's overall financial performance with regard to resources, expenditures, and accomplishments.

Responsibility and Authority to Pursue the EE Mission

One of the first steps for a savvy EE program marketing organization is to structure the implementing department along program responsibility lines, and not along functional lines such as engineering, operations, marketing, and customer service. A typical EE implementation organization structure is shown in Figure 11-2.

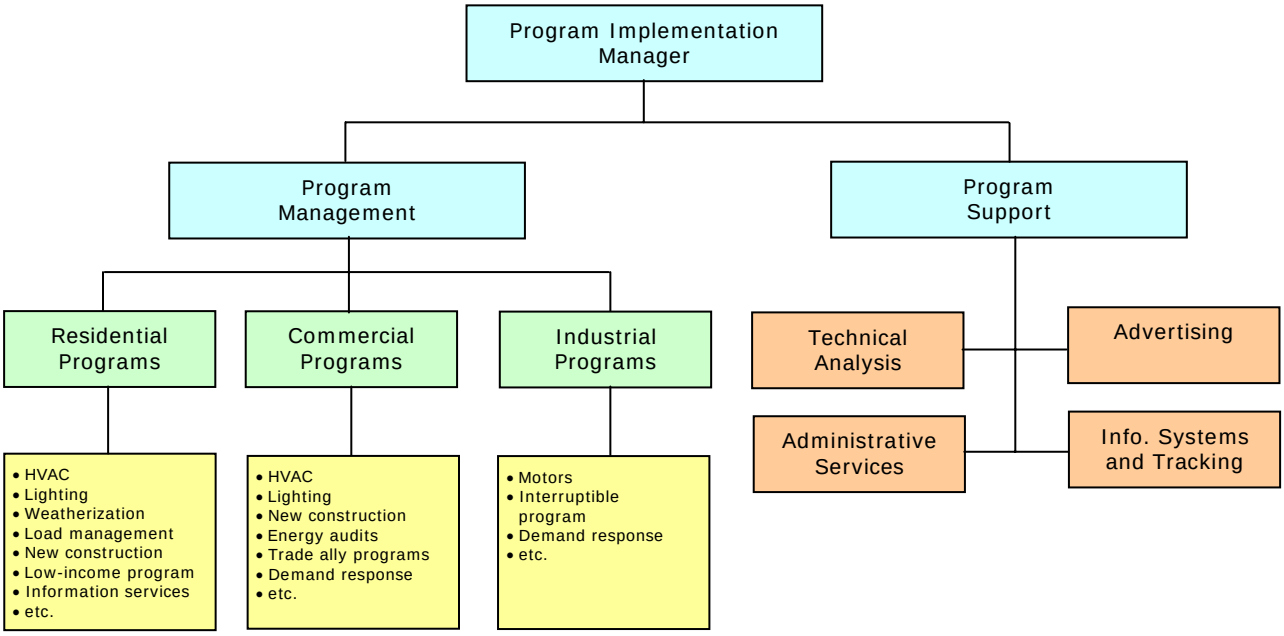


Figure 11-2
Energy Efficiency Program Implementation Organization Structure

Each program manager should receive the scope of responsibility and associated talent needed to achieve the program's objectives. Although some specialized support services may be "ordered" from other departments, such as meter and load monitoring equipment installation or recoding billing computers to handle bill credits or new rates, the department and its program units are organized to carry out their assigned EE programs. This creates the opportunity to hold program managers accountable for their actions and decisions in working with customers and trade allies. Some support functions within the EE department that are common to all programs, such as administration, technical assessment of devices, and monitoring and evaluation, may be shared across programs.

Executive Level Interest and Support

During the first two years of an EE program implementation, it is particularly important that senior management be visible in its oversight role and actively support the changes and adjustments needed in organization structure, interdepartmental cooperation, staffing assignments, and cutting through the normal organizational resistance to change (see Table 11-1). The level of organizational change and required management attention will be commensurate with:

- The size and complexity of the portfolio of EE programs (measured in dollars and load-impact objectives);
- The speed at which the EE program goals need to be achieved;
- The degree of regulatory oversight and expectation;
- The existence of shareholder incentive compensation mechanisms tied to EE resource performance; and
- The degree of customer and marketing orientation already instilled within the organization.

Table 11-1
Utility Executive Checklist to Launch EE Programs

1. Demonstrate visible executive support • Assure clear EE program reporting lines • Create an executive oversight committee • Monitor the flow of internal and external communications
2. Create an effective implementation organization with: • Responsibility • Accountability • Resources • Inter-departmental cooperation • Flexibility
3. Address staffing considerations • Internal transfers versus new hires? • Utility personnel or contract labor? • Acknowledge special skills are needed

Flexibility is Paramount

Flexibility is the key to success in EE program implementation. Program managers need the latitude to reallocate staff, change marketing techniques, and shift budget resources around to capture "real-time" opportunities and market feedback received every day. Commissions need to foster an atmosphere of flexibility to encourage utilities to adopt program changes based on monitoring and evaluation findings. Utility management and regulatory bodies may consider making certain operational and reporting rules less rigid to create sufficient latitude for EE programs to be successful. For example, an EE program budget put together in September for the following calendar year may be outmoded by March. Management and commissions prefer to see one-, two-, or even three-year budgets, and participation and impact targets. This may work out satisfactorily in the aggregate for the entire set of EE program plans and expenditures. However, market response, product supply constraints, and unanticipated media attention may cause individual programs to vary as much as 50% lower to 100% higher than the best planning and design assumptions can project. Flexible management can assure the utility stay on target or surpasses its goals.

Implementation Issues and Activities

EE programs come in a seemingly endless variety of forms and features. Unlike the EE program planning stage where program characteristics seem to fall into "neat packages," in the implementation stage, there are numerous facets and details to be considered. To quote Amory Lovins: "The energy problem [the transition from supply-side to demand-side and renewable resources] is conceptually solved, but about 50 years of details remain." The implementation challenge is depicted in Figure 11-3.

EE programs encompass many types, ranging from promotion of efficiency technologies to load management and rate strategies. Programs may offer information, technical assistance; financial incentives in one of a number of forms; utility-controlled equipment; or changes in the price paid for the quantity, quality, and timing of electricity use. Table 11-2 summarizes types of EE programs utilities are offering—often in combination. For example, many utilities have combined audit programs with information programs and free installation programs for more comprehensive services.

Once the utility establishes the department's organizational structure and addresses program-related issues, program delivery begins. Key activities for program delivery include fine-tuning marketing and procedural materials with final testing; planning and executing the marketing campaign; acquiring, orienting, and managing implementation staff or contractors; and following operating procedures and quality control.

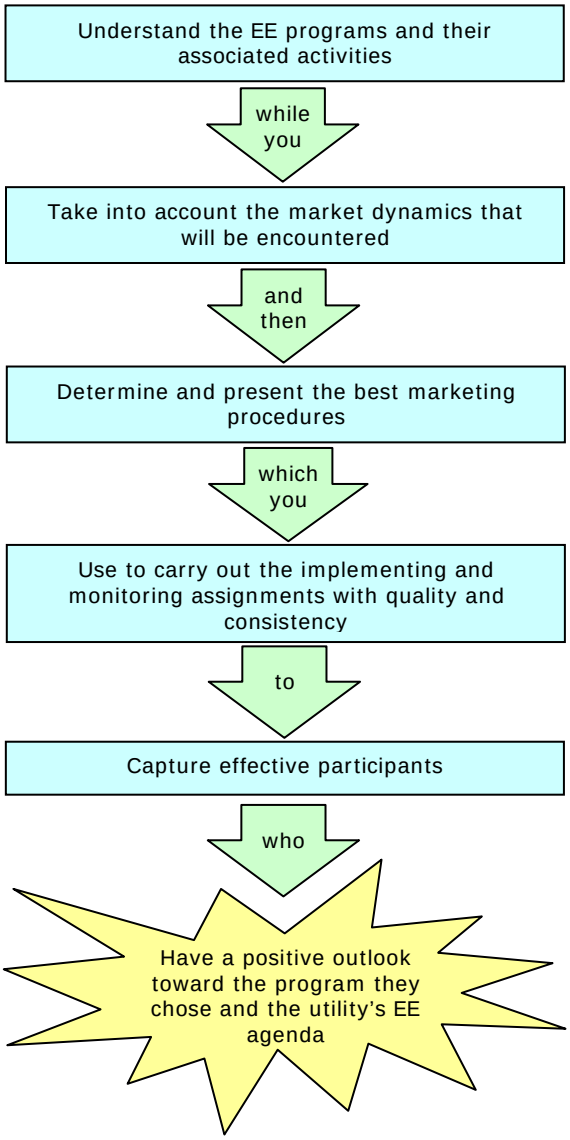


Figure 11-3
EE Program Implementation Challenge

Table 11-2
Energy Efficiency Program Examples

Efficient Equipment Rebates • Residential HVAC, lighting, appliance programs • Prescriptive rebates for commercial and industrial motors, HVAC, lighting • Customized rebates for commercial and industrial systems
Load Management • Demand response • Direct load control programs • Thermal storage
Information Services • Audits • Education programs • Technical assistance services • Technology promotion • Technology resource centers
Specialized Financial Mechanisms • Loans • Shared savings and performance contracting • Demand bidding programs
Direct Installation of Retrofit Equipment • Low-cost measures (e.g. residential water heater insulation, showerheads, compact fluorescent lamps) • Fluorescent lamp replacement in small commercial • Low-income comprehensive installation
New Construction Programs • Technical assistance to builders and buyers • Marketing campaigns for voluntary standards • Shared incentives between builders and owners • Design incentives to architects and engineers
Rate Strategies • Time-of-use rates • Interruptible rates • Critical peak pricing rates • Real-time pricing

Fine-Tuning Marketing Materials and Procedures

Advance market research cannot fully predict the realities of customer response, especially for the marketing and implementation details of individual EE programs. It is vitally important for new EE programs to get off to the best possible start by creating favorable impressions with customers and trade allies. Therefore, before launching a full-scale program, it is critical to test key features of a program. These include marketing materials, information/education materials, application and customer information forms, and participant intake procedures.

It is important to test marketing materials to determine if customers are receiving the right message, information, and appropriate level of detail to aid their consideration of program participation. Utilities tend to be conservative and careful organizations. Modern advertising, however, dictates that media and messages need to be bold and imaginative to capture customers' attention. The choice of informative marketing materials over offbeat promotion may

mean the difference between general program awareness and high response rates that exceed participation and impact goals.

Plans for program materials and procedures also merit advance testing. Interviews with trade allies and focus groups with customers can identify what supplemental information materials or educational services might be needed to support a customer's decision to consider and adopt a new technology. Program application and customer information forms should also be tested for their clarity and ease of use (by both customers and program staff) to ensure obtaining the most useful information needed for tracking and evaluation purposes. Even internal participant intake procedures should be assessed in terms of necessary processing time and cost and to assume that participants will be satisfied by their contact with the utility.

Planning and Executing the Marketing Campaign

One of the most critical areas for inter-departmental cooperation may be in assigning the responsibility for planning and executing the marketing campaign and supporting advertising and promotional activities. Utility experience reveal that this placement may be in one of four places: the program implementing organization; the utility's advertising agency "of record" reporting to the corporate communications office; or a second advertising agency selected to manage all the EE marketing accounts and reporting to the program implementing organization.

In making a selection among these alternative placements of promotional responsibility, utility management needs to consider which alternative promises:

- An understanding of what is involved in marketing EE programs—a complex combination of product and service that is more intangible than selling consumer products but less general than corporate image creation;
- Effectiveness in developing the ensuing marketing plan and tactics;
- Reasonableness of proposed budgets for program marketing;
- Familiarity with how to execute EE program marketing activities with customers and trade allies; and
- Responsiveness in turnaround time.

The marketing placement decision also should consider issues related to the utility's corporate image such as:

- Will each EE program be marketed singly or as part of an integrated marketing strategy (an umbrella program) under which all individual programs will have some unique treatment?
- Will each program's marketing communicate its own message, or will there be coordination with the utility's general image communications and/or its customer services marketing style?

Acquiring, Orienting, and Managing Implementation Staff or Contractors

If not reassigning existing staff (as discussed previously) to EE program implementation roles, utilities can choose between hiring new staff and using contract staff. Utility management should consider the following factors in reaching its decision:

- What is the total number of personnel required?
- What skills are needed to carry out the EE programs, and do these skills exist in other utility departments?
- Can personnel be spared and reassigned from the departments where useful skills already exist in the organization?
- Will the level of work from various EE programs be fixed or variable? Can utility personnel accommodate any variability in program timing or staffing needs?
- How much start-up time is needed to implement the DSM programs, and is there sufficient time to allow less experienced staff to progress along a learning curve?
- If new staff must be hired, will the personnel department be effective in recruiting the types of individuals and skills needed?

A personnel department's effectiveness in recruiting the talent and skills needed for EE program implementation may hinge on how well the utility has addressed the role of EE in the organization's resource and customer service plans. If the decision is made to recruit new staff from outside the utility, the questions become:

- Can the utility recruit staff with marketing, sales, and other skills into a utility company environment?
- Will the new staff gain the respect of the utility organization sufficiently to thrive and stay?

For example, if a utility organization has traditionally emphasized engineering and economic analysis skills as the keys to career mobility, will new staff with marketing and behavioral sciences skills be able to gain the cooperation of long-standing staff in traditional departments? Utilities must be attentive to creating attractive career-path options for these individuals and may choose to create rewards for staff with critical skills to stay in the department and recognize a "can-do" attitude toward obtaining EE resources. Retaining the stars may be particularly difficult if other industries, including manufacturers of EE technologies or energy service companies, view well-trained utility staff as perfect recruits for sales, marketing, and management positions.

Contract Labor Adds Flexibility and Enhances Capabilities

There are several reasons why many utilities choose to use contract labor for many or even most EE program delivery personnel requirements:

- Many utilities do not have a cadre of marketing staff who understand how to work with trade allies to change the energy equipment marketplace, building design, and related services, nor do they have the technical staff to understand end-use technologies and building systems analysis. To recruit new employees and train them or retrain existing utility personnel, and then work through the learning curve, can be a one- to three-year process.

- Other utilities are reluctant to create a large group of specialized marketing and technical employees because they are unsure of the ultimate size or cost-effectiveness of EE programs or of a long-term interest on the part of regulators.
- The required personnel skills can change over time as program features and services change, some programs grow, and others wane. It may be faster and easier to secure a flexible work force using contractors.
- A utility may find itself unable to find or attract the new talent needed to run EE programs. Marketing-oriented people and those with field-oriented expertise in building and equipment may be disinclined to seek work with utility companies—either because of the large organizational image or the fear of limited promotional opportunity when competing against utility engineers and rate analysts.

There are two essential requirements to orienting and managing staff activities in EE program implementation: orienting staff to keep the program's true objectives in focus, and matching staff skill to be tasks required.

Staff Orientation

One of the key s to an effective and efficient EE program implementation experience is to ensure that all staff involved in the program, from the EE program manager to the phone bank personnel and clerical staff, understand the program's true objectives and keep these in focus when talking with potential program participants. These staff need enough information to identify opportunities for customers to participate in the particular EE programs that are best suited to them. Every possibility cannot be spelled out in advance. Staff orientation should address:

- Program objectives, load shape objectives, reasonable costs, target customer markets, and end uses;
- How customers use energy, available EE technologies, their features, and pros and cons; and
- Customer decision factors, service needs, and styles of operation and decision making.

Match of People and Their Skills to the Required Tasks

It is important to match the technical skill level and interpersonal style of the implementation staff to the targeted customer population and the stage of the customer's contact (e.g., initial interest, technical assessment, and making the decision to participate). EE program experience points to the value of assigning personnel with the right mix of skills to promote and support EE programs. Engineers, for example, are essential in handling discussions with large businesses' facility managers about participation in a curtailable load management program, or how to calculate a customized rebate for an efficient HVAC system retrofit. However, it is not necessary to utilize engineers to gain initial market interest from most customers; the promotional and marketing staff can call upon technical staff when needed. Residential customers, for example, may respond best to marketing and customer service staff.

In an audit or technology rebate program for commercial customers, it is useful for staff to possess both technical analysis skills and financial knowledge to explain a customer's energy savings benefits in terms of their business economics.

Operating Procedures and Quality Control

Throughout the delivery of EE programs, managers and staff must be attentive to the following implementation procedures to assure several objectives:

- Monitor the flow of activities to ensure administrative costs are kept to a minimum by reviewing paper flow, occasionally tracking staff time to identify time traps that may signal problem areas, and convening clerical and implementation staff to solicit ways to improve operations.
- Review program implementation logistics or mechanisms to ensure that these support the program's desire to enlist participants. Check for a simple decision process, easy response mechanism, and personalized customer service whenever possible.
- Assure quality control in all information collection, customer contact, and equipment installation so that important information is obtained and processed accurately and there is consistency in how staff interprets information or make judgment decisions.

Monitoring and Tracking

Developing EE resources dictates that utilities have good information about what they are doing and accomplishing, with what markets, and at what costs. This requires investment in information collection, tracking, and analysis systems that support management and reporting needs for:

- Program implementation (milestones, market penetration, and expenditures);
- Program marketing (customer participation rates, participating customer characteristics, bases of trade ally support);
- Evaluation and planning feedback (measuring or estimating actual load impacts, identifying non-participants and their barriers to participation, and determining the effectiveness of market intervention);
- Monitoring program contractor performance;
- Tracking and reporting progress of individual customers; and
- Regulatory reporting on utility progress in achieving EE objectives and prudent spending of ratepayer funds.

Monitoring Provides Feedback to Keep Programs on Track

The style of the implementation organization's program activities and monitoring might be characterized as one continual feedback loop involving a series of "informed trial and adjustment" steps. The listening and feedback activities are supported by quantitative and qualitative information from the field on how well programs are working in the market. The entire sequence might look something like the diagram in Figure 11-4.

The value of agile and flexible implementation and management is the ability to adjust program details, improve staff knowledge and effectiveness, and change course when conditions and opportunities warrant. To accomplish these objectives requires monitoring the implementation activities supported by a program-tracking and database system. These activities can detect whether a program is being carried out as designed, if target customers understand the program and are responding as anticipated, if there are bottlenecks in program implementation and administrative procedures, if the program is meeting its goals (costs, participation goals, installations, energy and demand impacts), and if program features seem to be addressing market needs. Such systems are also used to track and encourage the progress of EE project for large individual commercial and industrial customers. Some of this information is inherently anecdotal or qualitative, but other aspects can be used to make implementation refinements and corrections in program marketing tactics, operational procedures, or customer contact activities to increase the program's effectiveness. These systems as a whole are useful to program implementers, administrators, managers, and evaluators.

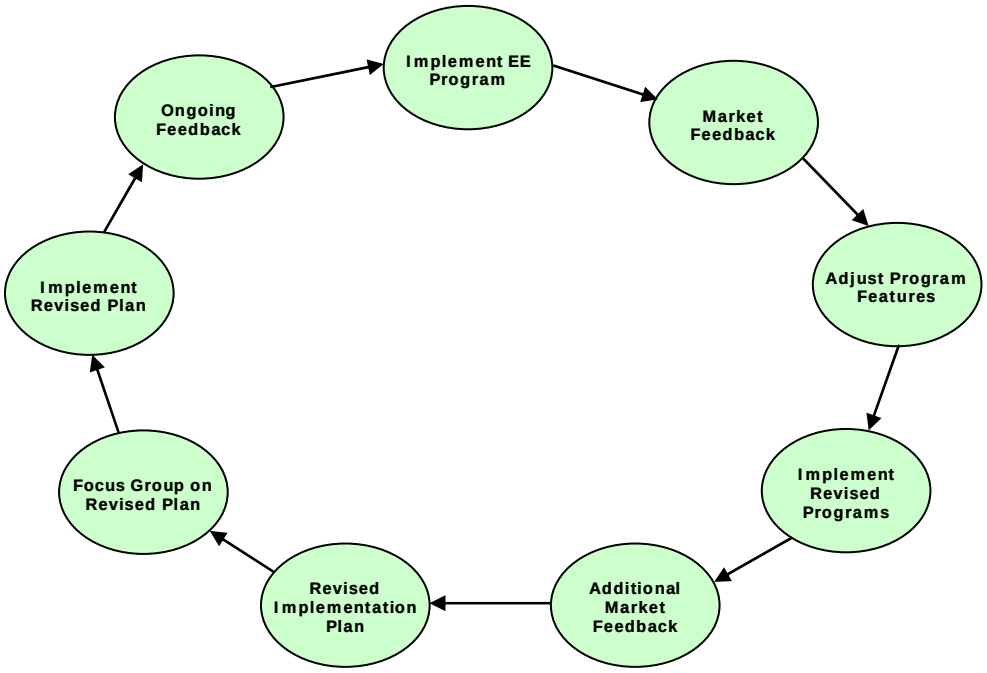


Figure 11-4
EE Program Implementation and Monitoring Feedback Loop

The case study presented in Table 11-3 demonstrates how the collection of quantitative and qualitative information in the monitoring process raises implementation issues. The "Conclusion" section lists corrections to these issues to ensure the achievement of the utility's goal of improved customer service and increased, reliable load shifting.

Table 11-3
Case Study of a Commercial/Industrial Demand Response Program

Objective	Demand reduction on critical peak days for bill credits.
Target Audience	Commercial/industrial customers.
Design Issues	
Eligibility	Customers with 200+ kW loads and have interval meter
Equipment	Requires customer to install hardware and/or software that interacts with facility's control system to automate load shed on critical peak days
Expected impacts	15 MW of load shed potential
Delivery mechanism	Customers have choice between critical peak pricing rate or voluntary demand bidding
Participation target	200 accounts
Implementation Issues	
Marketing strategy	Some customers are do not see value of automating their load shed; Some customers have misconception that the utility will gain the ability to shut down their loads without warning
Utility support	Program implementing organization requires access to interval meter data for each participant for monitoring program performance
Equipment eligibility	Load reductions achieved by process changes, production shifts, HVAC changes, and lighting system shutdown
Incentive level	Varies by the participant's baseline load characteristics; Incentives are necessary to solicit participation
Delivery experience	Most customers chose voluntary demand bidding over switching to the critical peak pricing tariff
Participation	82 customers accounts (41 % of target)
Load impacts	22 MW of load shed potential
Conclusions	
• Involve utility customer account representatives in participant recruitment process • Work with utility to identify list of potential participants that are already on the critical peak pricing rate • Program implementer signs indemnity agreement with utility so that access to customers' interval meter data can be granted • Clearly indicate method for calculation of customers' incentive payment amount in participation agreement document • Although the program was not able to achieve the targeted number of customer accounts, the load reduction target was exceeded. It would be better to set program goals based on load reduction instead of number of participants.	

Databases Facilitate Tracking Quantitative Information

The program tracking and monitoring system is typically set up in a database format. It may be a stand-alone system within the EE program implementation department, or it may be integrated with a utility's customer information system containing customer characteristics and billing histories. Figure 11-5 illustrates some of the data sources and applications of a tracking system.

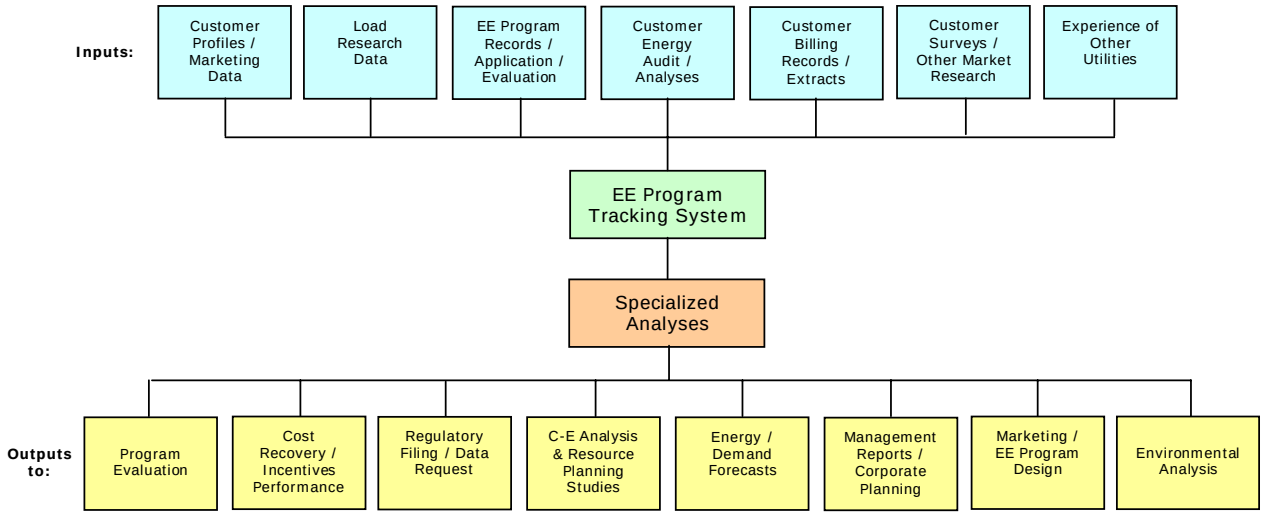


Figure 11-5
EE Program Tracking and Monitoring: Data Sources & Applications

For this system to be useful for all interested department, careful thought must go into the system's design, especially with regard to customer identifying codes, uniformity in terms and definitions, and accuracy of information. Meetings with all departments concerned are well worth the time involved upfront in planning the database. In the past, many utility data-collection efforts were of limited value for EE program planning because of the single-purpose intent for use of the data. For example, many market research studies have been conducted on an anonymous customer basis, where demographic information could not be tied to community, zip code, or account number. In the commercial/industrial sectors, much of the customer and load research information in the past has been collected on a rate class basis, without differentiation for SIC codes or end-use equipment.

The interrelationships among EE program planning, program design, implementation, monitoring, and evaluation dictate that careful attention be paid to customer identifiers, end-use information, and business or building-type categorization. Effective database design requires ongoing coordination among several departments responsible for market research, load forecasting, marketing services, corporate planning, load research, rate planning and analysis, customer service, billing, and information systems.

State regulatory commissions are focusing more attention on holding utilities accountable for the large sums spent on EE programs to ensure that the expected EE impacts are realized cost-effectively. This makes the monitoring and evaluation steps even more critical and subject to scrutiny.

Qualitative Information Valuable in Tracking Performance

Qualitative information is equally valuable in understanding whether a program's design and implementation procedures are effective in capturing a potential market for EE programs. Qualitative information can be observed or relayed by staff, customers, and trade allies. One routine way to obtain this information is to encourage program staff to spend time in the field, meeting with customers and getting first-hand feedback from suppliers, retailers, service providers, and contract-delivery organizations. Another useful technique it to conduct focus group discussions to obtain early feedback on a program's operations. For example, a utility may schedule a group meeting at the early stages of a program's implementation to obtain feedback among utility business representatives and customer service personnel, trade allies, and selected groups of customers. Such discussion formats are relatively low methods to obtain helpful anecdotal information on a program's performance compared to the more rigorous methods used for program evaluation studies that are discussed in Chapter 12.

Case Study of Program Implementation in a Hard-to-Reach Market

EE programs targeted to agricultural customers have typically received far less attention than those in other sectors, in part due to the size of the market relative to the residential, commercial, and industrial sectors. However, energy use in the agricultural sector is large—approximately 950 trillion Btu a year in the U.S. Until recently, agricultural customers in California have been underserved by energy efficiency programs. While agricultural customers in California have been eligible to participate in energy efficiency rebate programs, those programs were neither tailored nor promoted to this market. Furthermore, these customers have been historically reluctant to embrace change, making them a relatively hard-to-reach group.

In late 2006, an electric utility in California contracted a third-party firm to launch *Ag Efficiency Plus*, a program targeted for the state's 5,000 agricultural producers (growers and processors of all sizes) who collectively consume about 3.3 billion kWh per year. The program, which is ongoing, has a goal to reduce this annual electricity use by about 1%.

Ag Efficiency Plus Program Design

Ag Efficiency Plus is an incentive and education program. The program goals are firmly focused on reducing electricity use through installation of energy-efficient equipment in agricultural operations. Success is measured in savings generated by documented actions by the program participants.

The program design focuses on identifying electricity-reducing opportunities for agricultural customers and enabling them to install energy-efficient equipment. The two focal points of identifying opportunities and enabling action led to designing two "tracks" for enrolling in the program: audits and rebates. The audits provide on-site inspections of farms and processing facilities, followed by recommendations of specific rebate-eligible equipment measures that could improve the energy efficiency of operations. The audits are also a means by which to educate farmers and growers about the measures available to them, the energy and non-energy

benefits they provide, and how to identify additional energy-saving opportunities. Anticipating that on-site audits could not be provided to all candidate participants, the third-party implementer also built in less formal discussions, surveys, with customers which could be conducted on-site or by phone. These communications channels typically focused on specific issues of concern to customers, or served a more focused campaign within the program. For example, this channel was used to inform dairies about energy-efficient fan options as the summer approached, and to alert row crop farmers about drip irrigation prior to planting.

The rebates are intended to encourage and enable customer action. They were designed to cover all aspects of agricultural activities, including vegetable, grain, cotton, fruit and nut growing; dairying; ranching; crop packing; processing and storage; and also water supply. Rebates are offered for both farm-specific measures (e.g., milk precoolers) and more generally applicable ones (e.g., lights). Additionally, rebates are divided into two categories of measures, consistent with other programs in California—itemized and calculated measures. The itemized measure list consists of over 150 measures—usually off-the-shelf equipment such as lighting fixtures and fans—rebated at a fixed amount per-item that agricultural customers can choose from. Some measures are rebated based on size, such as acreage covered or motor horsepower size. The calculated measures are more often tailored to the specific needs of the customer. These tend to be larger projects, often involving multiple pieces of equipment. The calculated measure projects often garner larger rebates for their greater energy savings, and are more time-consuming since they require both pre- and post-inspections and site-specific calculations. By offering two mechanisms for recovering rebates on energy-efficient installations, the program accommodates two desirable characteristics for a broad array of projects: the speed and convenience of choosing off a list, and the flexibility of developing custom projects.

The outreach component of Ag Efficiency Plus has a number of distinguishing features as well. First, agricultural customers can enroll in the program either by having an audit or they can go directly to installation of a rebate-eligible measure. With the two tracks, customers who have either never considered energy-efficiency improvements or need help in evaluating different project and equipment options can obtain all the assistance they need, from identifying opportunities and understanding benefits of the alternatives to receiving technical advice.

The second unusual feature for a full-scale, sector-wide program is that much of the outreach and participant assistance is conducted on site. The program team consists of a call center and field representatives. In the design, the call center was set up to address inquiries about the program from equipment vendors and/or customers, make a number of measure recommendations, and provide assistance with the audit and rebate paperwork. The field representatives would conduct audits, provide technical advice, make custom measure calculations, and perform whatever inspections might be necessary.

A third key feature in the program design is the broad scope of the outreach. From the start, program awareness and energy-efficiency education was directed to the entire agricultural community. This meant not just the growers and processors but also local equipment dealers and contractors, associations, and farm lending bureaus. By directing promotional materials, educational sessions, and face-to-face contact to the broader set of agricultural market actors, the third-party program implementer made use of an influential supply chain for farm equipment decision makers. Even though this is a downstream program, meaning only the end users (farmers and processors who are the utility's customers) can receive the rebates, equipment

vendors have a great deal of influence in farm equipment decisions and also benefit from a program that encourages new equipment purchases. The marketing plan contains waves of mailings to and live contact with the customers, the vendors, and the associations.

Crafting the Marketing Message

Electric bill reductions and environmental benefits that program implementers usually cite to advocate making energy efficiency improvements are not enough to get a farmer to make changes. Other costs loom large, such as labor and water, and other concerns, such as productivity, hazardous waste, water policy, market prices. A marketing effort would need to highlight one of these issues to make the case for investing in energy efficiency.

While circumstances facing farm producers and processors make energy efficiency less attention-grabbing, some of the most pressing challenges to California farmers in 2007 (e.g. winter frost, summer e. coli outbreak, fires) have actually provided the program implementer with opportunities to address their primary needs while making the case for participating in the program. For instance, water allocation cutbacks became more pressing in 2007, forcing farmers to think of new ways to keep their crops alive with less water. So, while replacing a functioning irrigation system is not something a grower would ordinarily embrace, documented evidence showing that changing from traditional flood-irrigation or high-pressure sprinklers to low-pressure drip irrigation significantly reduces water use has attracted growers' interest in making the change. With rebates available for drip measures because they reduce electric pumping requirements, the program implementer was able to craft an effective message about the Ag Efficiency Plus program specifically for crop, fruit and nut growers: *install drip irrigation to save crops and, by the way, save electricity*.

The agricultural market, at least in California, is a collection of very diverse grower and processor markets—row crop growers, grain growers, fruit and nut tree growers, dairy farmers, hog and cattle ranchers, egg and poultry producers, citrus packers, juicing facilities, wineries, and more. The program message needs to tap into what concerns the grower or processor and be specific to their needs. The irrigation example in the previous paragraph is sufficient for many of the growers, but dairy farmers had a different pressing issue last summer: keeping their livestock alive and producing milk during the heat wave that hit California. For that market segment, the program implementer needed to highlight that Ag Efficiency Plus offers a variety of energy-efficient circulation fans at a time when dairy farmers were clamoring to buy any kind of fan that would provide relief. Accounting for differences in the types and seasonal timing of their various activities, the program implementer developed a unique marketing message for each of the fourteen separate market segments.

Implementation Realities and Findings

In taking the ideas from the drawing board to the field, the program implementer learned to make some adjustments and learned which appeal more to the decision makers and fit the decision making process in this market. The following are some field-tested responses to those ideas:

- Enrollment via audit turns out to be time-consuming and not more effective in generating projects than informal on-site visits. Farmers and food processors are typically a cautious, risk-averse group. Perhaps this is why the more informal contacts, often focused on a specific aspect of the farm operation, are more effective than more sweeping audits; farmers and food processors exhibit a preference for observing success one measure at a time. However, numerous customers install additional measures as their satisfaction with, and confidence in, the program builds. Repeat outreach to participants from the call center and/or field representatives is also important.
- The majority of participants go straight to installations and rebate, with minimal oversight from the program implementer beyond making recommendations and confirming the eligibility of equipment for rebate. Customers seem happy to make use of the simplicity that the itemized measure category offers. Having the full list of measures available via web and printed claim forms is enough to spur customers to initiate projects.
- More projects are completed when the field team sees farm and processing operations, makes recommendations, and helps customers fill paperwork. This is not surprising but the value of proactive support, rather than simple availability or reactive support, has been proven.
- Having a call center to complement "boots on the ground" field support is worthwhile but requires extensive real-time coordination. The program implementer has a real-time tracking system that accommodates notes from both the call center and field reps, and near daily calls between the two.
- Promotion to, and networking with, vendors is key to attracting customers to the program and getting projects done with proper documentation to assure rebate approval. What started as a promotional activity to this group has evolved into collaboration as vendors notify the program implementer of pending projects. The program implementer also helps the vendors by ensuring that the projects are rebate eligible.
- Bringing projects through to fruition (i.e. customer receipt of rebate claim) requires more field representative support than was originally anticipated. Even after investing substantial funding for installations, experience shows that a significant share of program participants would forego the submittal of rebate claim without an in-person request for signatures on the required paperwork.
- Word-of-mouth among farmers has led to customer-initiated inquiries and program-influenced projects. This further underscores the effectiveness of working with customers throughout the process from recruitment to installation to rebate claim. The call center/field representative combination makes that kind of ongoing contact possible and effective.

Case Study of Auto-DR Pilot Program Implementation

Automated demand response (Auto-DR) provides commercial and industrial customers with electronic, Internet-based price and reliability signals that are linked into the facility energy management control system (EMCS) and related whole-building controls. Auto-DR price and reliability signals trigger automatic customer-programmed load curtailment strategies. The Auto-DR price and reliability signals can be used to automate response to dynamic pricing as well as conventional interruptible and demand bid options. Enabling Auto-DR requires three basic technologies: a price or reliability signal generator (DR Automation Server); a communications device at each facility to receive the price and reliability signals (gateways and relays); and a customer provided facility energy management and control system or related system for lighting, HVAC and other controls. One important concept in Auto-DR is that the participant should be able to "opt out" or "override" a demand response event if the event comes at a time when a reduction in end-use services is not acceptable.

Auto-DR originated at the Demand Response Research Center (DRRC) at the Lawrence Berkeley National Lab, which has been operating Auto-DR pilot programs since 2003 in a number of commercial facilities in the state. Results from the pilot programs indicate that Auto-DR can deliver low-cost, reliable, consistently repeatable electric demand response in commercial facilities. Automating demand response improves the repeatability of the demand response, reduces on-site labor costs associated with manual demand response, and hardens the resource for utilities by requiring commitment to a consistent set of strategies. Automating demand response with standardized, open protocols provides an infrastructure for future wide scale implementation that can be extended into future building and appliance controls.

In 2007, the California Public Utilities Commission required California IOUs to deploy larger-scale Auto-DR in their service territories as a way to augment their demand response programs. The following describes one California utility's experience in implementing an Auto-DR pilot program in 2007.

Auto-DR under the Critical Peak Pricing Rate

Critical Peak Pricing (CPP) is a relatively new form of retail time-of-use rate (TOU) that relies on very high, critical peak prices, as opposed to the ordinary peak prices in TOU rates. A specified high per-unit rate for usage is in operation during times that the utility defines as critical peak periods. CPP events may be triggered by system contingencies or high prices faced by the utility in procuring power in the wholesale market. Unlike TOU blocks, which are typically in place for 6 to 10 hours during every day of the year or season, the days in which critical peaks occur are not designated in the tariff, but dispatched on relatively short notice as needed, for a limited number of days during the year. Some utilities in California are using the CPP rate program, as well as other programs such as demand bidding, as a means for determining Auto-DR events (i.e. customers participating in Auto-DR would automatically curtail loads during CPP days).

Figure 11-6 shows the Auto-DR control and communication system infrastructure with four example site types. The Demand Response Automation Server (DRAS) is at the heart of the controls and communications architecture. It provides a common signaling infrastructure for

economic- and contingency-based demand response. The DRAS is capable of managing thousands of facilities. Each facility is controlled using a DRAS client which is the bridge between the EMCS and the DRAS. For the pilot program in California, the subject of this case study, a stand-alone device called the CLIR (Client and Logic with Integrated Relay) was provided to participants. The CLIR resides on the facility Intranet and connects to the EMCS via dry contact relays.

Alternatively, since the DRAS uses standard Internet technology to send commands, many control systems can also connect directly to the DRAS with a software module. From an IT perspective, devices that are communicating with the DRAS behave just like computers accessing web pages on the Internet, making them easy to install and configure. Each facility manager has their own secure web page, called "My Site", from which they can configure their program settings and monitor their client devices and account information. This web page is available from anywhere on the Internet, so facility mangers can monitor their program status or tweak their operating parameters from anywhere in the world.

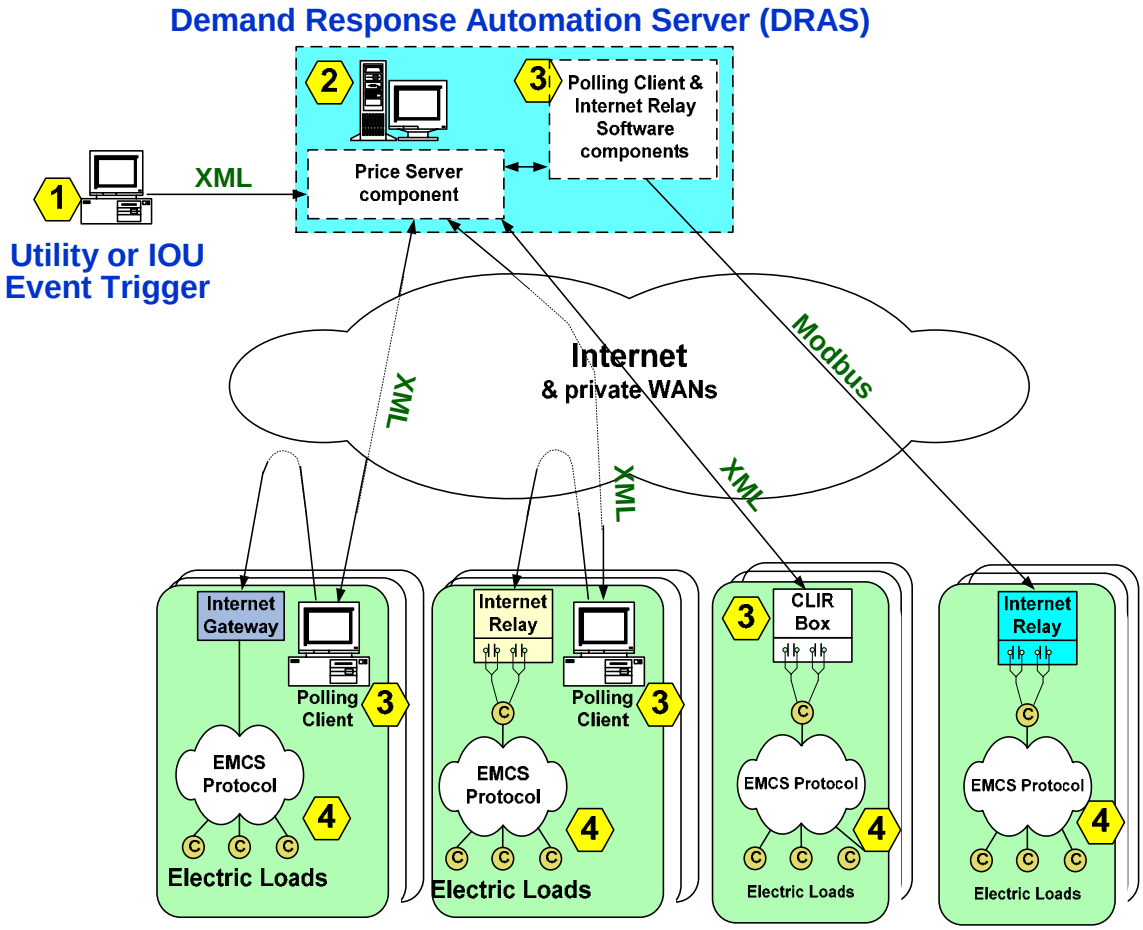


Figure 11-6
Auto-DR Communications System Infrastructure

When the utility triggers a CPP event, an XML message is sent to the DRAS indicating the event date. The DRAS creates an event notification table visible to all users and publishes an event-pending signal so that all the polling clients at participating sites receive this notification information. It uses the public Internet and private corporate and government intranets to communicate the CPP event signals to the facilities EMCS. When the CPP signals are received by the EMCS, it performs the pre-determined demand response strategies at the appropriate times.

Customer Recruitment

Shortly after the project's kick-off in early 2007, the utility prepared a list of customers that have high potential for Auto-DR implementation. Customers needed to participate in the Critical Peak Pricing (CPP) rate was a requirement, and thus the utility compiled a list of approximately 50 customers that are either already on the CPP rate or appear to have strong potential for financial benefits on the CPP rate. The utility then organized a meeting where the account executive for each of the customers in the target list was requested to attend. The approach was to have the account executives lead the customer recruitment efforts, and thus the objective of the meeting was to provide information concerning the Auto-DR Program and its related processes to the account executives. After the meeting, the account executives were tasked with marketing the Auto-DR program to their customers, which the account executives did through face-to-face meetings with their customers.

By the time the summer started (i.e. the demand response season), only a handful of customers had expressed interest in participating and appeared to have strong potential for implementing Auto-DR. One customer had the necessary hardware installed and software programmed at their facility in time to participate in the CPP events during the summer in an automated fashion. Four other customers are expected to complete the Auto-DR system installation and programming by the end of 2007.

Several factors contributed to the issue of why more customers were not Auto-DR enabled during the 2007 pilot program:

- The 2007 pilot program was limited to customers enrolled in the CPP program. However, the utility's account executives had difficulties getting customers to enroll into the CPP tariff, citing the CPP rate is a "tough sell."
- Most of the customers that were targeted by the utility were industrial customers. The process for getting industrial customers to become Auto-DR enabled requires more time than commercial customers because industrial processes require more in-depth analysis of the load shed potential and determination of the specifics of how to integrate the systems into the Auto-DR technology infrastructure. The time required for a controls contractor to complete the installation of the Auto-DR system is also longer for industrial customers.
- Many of the customers that were initially targeted by the utility were already enrolled in the CPP rate. Many of these customers have permanently shifted their schedules to avoid operations during the CPP peak hours. These industrial customers would not qualify for financial incentives provided under the Auto-DR program because they do not have additional loads that can be reduced during CPP events.

Other Implementation Issues

The following summarizes other issues that were observed during the utility's implementation of the Auto-DR pilot program:

- The method used by the utility to select customers to be targeted for Auto-DR resulted in a target list that almost entirely consisted of industrial customers. A recent analysis of the Critical Peak Pricing (CPP) tariff by LBNL has suggested that commercial customers can also be viable candidates for the CPP rate. The utility will need to include more commercial customers such as large retail stores and office buildings in future recruitment efforts.
- The account executives were utilized to directly market the Auto-DR pilot program to eligible customers. Judging from the lag times it took to report on whether or not their customers were interested in Auto-DR and the recruitment realization rates, it appears that many of the account executives had a difficult time selling the CPP program and/or Auto-DR to their customers. In the future, the utility and its contractors will need to provide more training to the account executives so that they are better prepared to answer questions and address customers' concerns regarding the Auto-DR process and technical specifications.
- The process for enabling industrial customers with Auto-DR requires significantly more time and technical coordination than for commercial customers. Industrial processes require more in-depth analysis of the load shed potential and determination of the specifics of how to integrate the systems into the Auto-DR technology infrastructure. The time required for a controls contractor to complete the installation of the Auto-DR system is also longer for industrial customers due to the sophistication of the hardware integration.
- Within the context of an Auto-DR program, technical coordinators (TCs) are third-party contractors that play the role of ensuring customers and their controls contractors install the Auto-DR systems correctly, and to troubleshoot problems in the field. The utility decided to eliminate TCs from the 2007 pilot program design. By not having TCs, there were various technical challenges with the few installations that were put into place. For example, at one customer facility, there were technical issues with the technology but the customer's controls contractor's scope of services did not include servicing if there were problems. As such, it was necessary for members of the utility's team to visit the customer's site in order to troubleshoot after installation.
- The utility's staff served as the operator of the software platform utilized for Auto-DR (known as the DRAS). However, the duties and responsibilities of the operator were not sufficiently defined and assigned to utility's staff. For instance, there were periods when communications with a customer's Auto-DR system went offline for a long period of time without being noticed by the staff. In the future it will be necessary to provide extensive training that will allow for a better description of roles and responsibilities to the utility personnel serving as the Auto-DR system operator. When there are many more participants, it will be necessary to assign multiple staff members to function as the operator so that at least one person is available for the operator duties on any given day.

Summary and Resources

EE program implementation places programs into the field, building on the results of the previous steps. This chapter has described the issues associated with the implementation and monitoring of EE programs. Administering EE programs requires the commitment of upper management resolving organizational and staffing issues and substantial human, financial, and organizational resources. Ongoing program monitoring provides important feedback on program status to allow for early adjustments to ensure program success. Program monitoring becomes even more critical when utilities receive performance incentives for EE achievements.

Resources

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12
EVALUATION, MEASUREMENT AND VERIFICATION

Introduction

Evaluation, Measurement and Verification (EM&V) of the EE program is the final step in the process illustrated in Figure 12-1.[74]

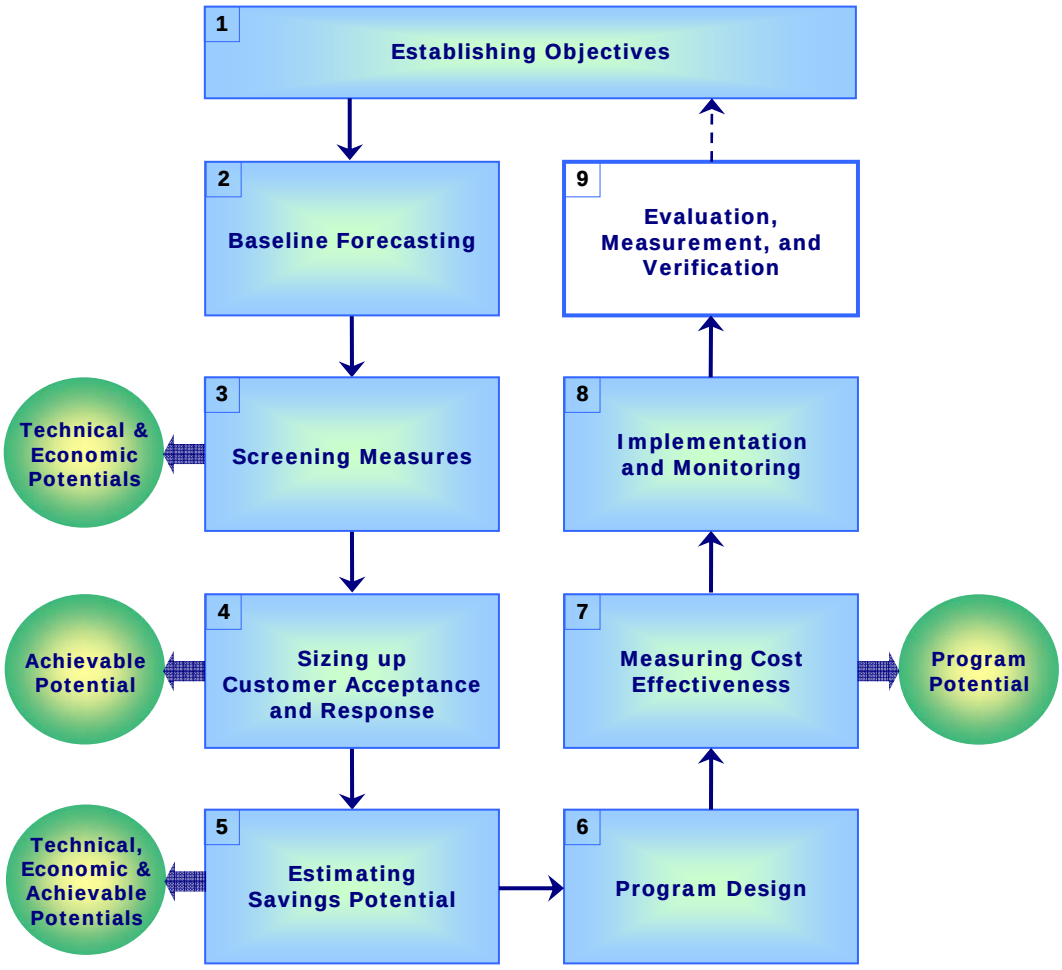


Figure 12-1
EE Program Process, Step 9: EM&V

[74] In the context of this document, "EE" refers to both energy efficiency/conservation and demand response.

Evaluation encompasses the periodic assessment of the effectiveness of EE programs in achieving their objectives. Evaluation gives valuable feedback on how the programs are performing and is important for demonstrating to regulators, investors, and shareholders the value of EE program activities. It can also help the utility make "in-stream" modifications to delivery strategies and administrative procedures and revise the entire EE program's process when appropriate.

Measurement and verification (M&V) is often mentioned within the context of energy efficiency implementation at the measure level: measuring the savings due to the installation of a specific EE measure and verifying the accuracy of those savings. Within the broader context of EE programs, M&V activities can assist utilities to perform the impact evaluation of their programs.

This chapter describes the issues associated with the evaluation of EE programs and the methods employed to conduct process and impact evaluations.

Dimensions of Evaluation

Program evaluations address a broad range of issues concerning the effectiveness of programs in achieving their objectives. They generally fall into one of the following two categories:

- **Process Evaluations**. These generally address utility operations, including the efficiency of service delivery, effectiveness of promotional strategies, coordination of programs with other EE activities and utility functions. They also analyze customer satisfaction with program services and related issues dealing with market acceptance.
- **Impact Evaluations**. These examine the quantifiable effects of a program, including documentation of program participation rates and measure adoption patterns, performance of DSM technologies, and energy and load impacts. Measurement and verification (M&V) activities provide important input to impact evaluations.

Each type of evaluation is useful at specific stages of the program planning and implementation process. Process evaluations are often conducted during the formative period of program implementation after some initial experience with administrative procedures and delivery strategies. The results at this stage recommend modifications to these procedures and strategies before they become rigid.

Impact evaluations often require data on energy consumption and related variables for a full year after installation of efficiency measures. As a result, the analysis required under impact evaluations typically is performed during the second year of implementation at the earliest.

It is useful for discussion purposes to distinguish between the two types of evaluations. It is also important to recognize that the issues in these areas overlap considerably. For example, the effectiveness of program delivery strategies, a central process issue, is largely measured in terms of participation and adoption rate, which are key impact issues. The energy and load savings from measures typically vary by customer segment. Depending on the perspective from which this issue is addressed, it could be viewed as a process or impact issue.

This overlap suggests that evaluations need to be closely coordinated and their results integrated to provide an overall assessment of EE programs. Process evaluations during the formative stages of program implementation may identify issues that should be explored in greater depth as part of subsequent impact evaluations.

Planning the Evaluation

Careful planning is critical to ensure that program evaluations serve the program and organizational needs effectively. It is important that these plans be developed at an early stage of the program design so that the resources and data collection needed for their implementation can be provided. Evaluation plans should cover the following areas:

- ***Objectives of the Program***. It is essential that the objectives of the EE program be clearly stated in order to ensure that the evaluations address the appropriate issues. Poorly defined program objectives lead to poorly focused evaluations.
- ***Objectives of the Evaluation***. The goal of program evaluation is to assess how effectively the program is achieving its objectives. The objectives of evaluations usually follow naturally from the program objectives.
- ***Evaluation Approach***. The method for conducting the evaluation should be defined as precisely as possible. For example, will energy savings be estimated using engineering, statistical, or metering techniques? What will be the exact nature of the calculations or analyses performed under the proposed method?
- ***Data Collection Requirements***. The data requirements for the analyses and their sources should be specified under the evaluation plan. These data include sample sizes for direct measurements and surveys, the variables to be collected, and the time periods for which they are measured.
- ***Schedule***. The schedule for data collection, analysis, and reporting should be specified to ensure that the necessary tasks are performed in a timely manner.
- ***Evaluation Resources and Work Assignments***. The evaluation plan should include a budget for its execution. The budget should be consistent with the planned data collection and analysis. One common rule of thumb for evaluating full-scale EE programs is that the cost of the evaluation should not exceed 10% of the implementation budget. The evaluation planning should take into account the expected value of the information relative to its cost.

Once the evaluation plan is in place, it should serve as a guide to determining what needs to be done at what stage of the program design and implementation process. However, the evaluation plans themselves must be flexible. As important as they are, evaluation plans are not written in stone. As new issues arise during program implementation, evaluators must be prepared to revise their strategies to respond to those issues.

Example of Evaluation Planning for an Automated DR Pilot Program

The following is an example of the issues that were considered in the planning of an actual automated demand response (Auto-DR) pilot project.

Program Objective and Results

A utility in California implemented an Auto-DR pilot program in 2007 with the stated goal of enabling 10 to 20 customers or service accounts to become Auto-DR capable within the context of the utility's Critical Peak Pricing (CPP) tariff. The pilot effort serves as a stepping stone for the utility to expand the program in 2008 and beyond.

A total of 53 customers were targeted as potential Auto-DR participants during the course of the pilot program. Five of the 53 customers that were targeted are expected to become Auto-DR enabled as a result of the program's efforts in 2007. However, only one of the five customers was completely Auto-DR enabled in time to participate in the CPP events called during the summer of 2007. The five customers represent a total of eight service accounts and approximately 2 MW of load shed potential.

Evaluation Objective

The objective of the evaluation is to analyze and assess the results of the pilot program and formulate recommendations for implementation improvements in the 2008 program expansion. Due to the limited scope of this objective, the utility opted to have the Auto-DR implementation contractor to perform this evaluation instead of hiring a third-party contractor.

Evaluation Approach

The evaluation will consist of both process and impact evaluation elements. Specifically, the following approach will be used:

- Interviews with all relevant stakeholders, such as the utility program manager, the utility's customer account representatives that were involved in recruiting customers, the customers themselves, controls contractors that installed Auto-DR systems at customers' facilities, and the program implementation contractor staff. These interviews will be designed to solicit input and information that will assist in the formulation of recommendations for program implementation and process improvements.
- Numerical analysis of electric meter data to assess the (one and only) customer's automated load shed performance (relative to the CPP baseline) during the summer of 2007. The average load shed across all CPP events during the summer of 2007 will be compared to initial estimates to gauge Auto-DR's capability to fulfill expectations about load reduction delivery.

Data Collection Requirements

It will be necessary to obtain interval meter data from the utility's monitoring and tracking system for the single customer that was able to participate in the CPP events in an automated manner. In order to develop the CPP baseline according to the California Public Utilities Commission's (CPUC) accepted methodology, it will be necessary to obtain the interval meter data that include at least one month before each CPP event.

Schedule

The CPUC requires that all California utilities document and file the following year's program implementation plans by November of each year. Since this evaluation will provide critical input and recommendations for next year's Auto-DR implementation plan, it would be important to complete the evaluation by mid-October 2007 at the latest.

Process Evaluations

Process Evaluation Issues

Process evaluations identify problems and recommend actions for the various aspects of an EE program, such as internal administration, promotional practices, program delivery, incentive levels, and data tracking. Process evaluations promote utility awareness of customer attitudes, perceptions, and needs, and are intended to improve customer satisfaction and identify market threats and opportunities. Process evaluations provide a systematic way for utilities to learn from their program implementation experiences, both within a particular program over time and across programs being fielded simultaneously or contemplated for the future. Process evaluations help assure regulators and other interested parties that EE programs are being implemented effectively and modified or refined as necessary. On a larger scale, process evaluations contribute to the industry-wide knowledge base about EE programs, the best ways to implement them, and the pitfalls and barriers that must be overcome for such programs to succeed.

Broadly defined, process evaluations are concerned with the application of interview and survey techniques, site visits, and document reviews to assess the performance of EE programs. For example, a process evaluation might address the administrative procedures for delivering program services by interviewing utility staff and contractors. This would result in recommended procedural changes to increase program effectiveness. Impact evaluations, in contrast, estimate the quantifiable effects of a program, such as the savings in annual energy consumption and seasonal peak demand.

Recognizing the overlap with impact evaluation and the need to integrate process and impact components, this section discusses the issues and methods relevant to process evaluations.

The emphasis of process evaluations will differ depending on the stage of program implementation at which they are conducted. Process evaluations are commonly performed during the pilot phase of implementation and at regular intervals during the full-scale implementation.

During the pilot phase, process evaluations should focus on the following issues:

- Analyzing and assessing preliminary feedback from customers and from relevant trade allies;
- Gathering and synthesizing utility staff perceptions on preliminary experience with the program;
- Providing decision makers with information for determining the viability of the program concept;
- Identifying and formulating responses to anticipated problems as a pilot program is ramped up into a full-scale program; and
- Assessing the performance of the program management structure and supporting reporting systems.

During full-scale implementation, the focus typically shifts to the following issues:

- How the program is perceived by utility customers (both participants and non-participants);
- Changes in market response, quality of service, or milestone performance;
- Interactions with other programs available to the same set of eligible customers;
- The effectiveness of promotional strategies and incentive levels as increasing levels of market saturation are obtained; and
- Changes in the marketplace and their effects on free ridership and spillover effects.

Six key areas of investigation are included in process evaluations:

- ***Program Design***. How the program was designed, who was involved, and how were the issues explored and resolved? What goals and objectives were set forth, where did they come from, and why were they selected?
- ***Program Delivery***. How was the program delivered to the customer? What were the roles and responsibilities of the various parties? This issue is particularly important for utilities to track for programs delivered to customers by non-utility staff, i.e. third parties.
- ***Program Implementation***. What are the various implementation steps for this utility in particular? What procedures must be followed as the program is delivered? (This is often the long-term view of the delivery mechanism.)
- ***Program Administration***. This area of evaluation encompasses the nuts and bolts of the program: the forms, contracts, payment procedures, allocation of resources, and coordination with utility procedures. Quality of measure installation and cost control are also relevant issues.
- ***Market Response***. How is the market changing as a result of the program? Are trade allies selling more energy-efficient equipment because of the program? Will they continue to sell the equipment when the program ends? Has the market "moved" or "transformed?"
- ***Customer Response***. Are customers responding to the program? Has their satisfaction with the utility changed as a result of the program? Are the program's actions leading to changes in behavior?

Process Evaluation Methods

Process evaluations are generally conducted through interviews, surveys, site visits, and document reviews. The advantages and disadvantages of each of these methods are summarized in Table 12-1. Some of the important considerations in the application of each of these techniques are discussed below.

Interviews

Two of the most commonly used methods for investigating process evaluation issues are personal interviews and focus groups. Both methods are effective in obtaining a broad range of information from customer or key players in the program delivery network. In contrast to surveys, interviews allow respondents the opportunity to respond to open-ended questions or topic areas and to explain the reasons for their responses. Typically, interviews are conducted for only a small number of people because they are relatively expensive on a per-respondent basis. Care should be taken in interviewing strategies to select the key people in the program delivery chain and to cover the range of topics of concern specified in the evaluation plan. Focus groups are useful when the evaluator wants to obtain reactions to views by other people and to identify consensus versus outlier opinions.

Surveys

Surveys are most effective when the evaluator needs information from a large, representative sample on well-defined questions. The evaluator must be concerned with a variety of sampling and survey design strategies in applying this data collection method.

Site Visits

Field observation of program installations for physical inspection and direct measurement are useful where survey responses are unreliable or where respondents cannot easily provide the information. Due to cost considerations, the evaluator may wish to limit the number of site visits. Stratified or purposeful sampling techniques may be appropriate to obtain a representative distribution of observations within the evaluation budget constraints.

Document Review

Program and related documents often provide valuable information about experience with the EE program that is relevant to the process evaluation. Potential sources include:

- Program files;
- Regulatory documents;
- Field staff files;
- Database records; and
- Contractor files

Table 12-1
Advantages and Disadvantages of Process Evaluation Methods

Method	Advantage	Disadvantage
Discussions and interviews	Impressionistic Qualitative In-depth	Potential for bias Small sample
Surveys	Good breadth of coverage Quantitative	Limited depth
Inspections and site visits	Impressionistic Qualitative Experiential	Potential for bias Costly Small sample
Document reviews	Qualitative Easily referenced	Potential for screening

Impact Evaluations

Impact evaluations are concerned with quantifying the effects of EE programs. Measurement and verification (M&V) is discussed first in this section because, if available, M&V activities conducted by facility owners and EE project implementers can help utilities to quantify the effects of the their EE program (in fact, some utilities actually conduct the M&V activities for their EE program participants for this very purpose). The later portions of this section discuss the impact evaluation at the broader program level.

Measurement and Verification

Measurement and verification (M&V) is the process of using measurement to reliably determine actual savings created within an individual facility by an EE project. Savings cannot be directly measured because they represent the absence of energy use. However, savings can be determined by comparing measured use before and after implementation of a project.

The comparison of before and after energy use or demand can be made on a consistent basis using the following general equation:

$$Savings = [Before_{(Energy,Demand)} - After_{(Energy,Demand)}] \pm Adjustments$$

The "Before" term in the above equation is more commonly known as the "baseline." The "After" term is also more commonly called the "post-installation" or "post-implementation." The "Adjustments" term in this general equation is used to re-state the energy use or demand of the baseline and post-installation periods under a common set of conditions in the event that some operational parameters outside of those directly influenced by the project also changes. An example of this is the determination of the savings due to a lighting retrofit in an entire department store when the store's hours of operation also changed during the same timeframe as

the retrofit project. This adjustments term distinguishes proper savings reports from a simple comparison of cost or usage before and after implementation of an EE measure. Simple comparisons of energy use and demand without such adjustments report only the changes and fail to report the true performance of a project. To properly report "savings," adjustments must account for the differences in conditions between the baseline and post-installation periods.

M&V activities consist of some or all of the following:

- Meter installation calibration and maintenance;
- Data gathering and screening;
- Development of a computation method and acceptable estimates;
- Computations with measured data; and
- Reporting, quality assurance, and third party verification of reports.

M&V may not be necessary when there is little doubt about the outcome of an EE project or no need to prove results to another party. However, it is still wise to verify that the installed equipment is able to produce the expected savings. Verification of the potential to achieve savings involves regular inspection and commissioning of equipment. However, such verification of the potential to generate savings should not be confused with M&V since verification of the potential to generate savings does not involve site energy and/or demand measurement.

Some of the reasons why facility owners or energy efficiency project investors involved in implementing an EE project should perform M&V are:

- ***Increase energy savings***. Accurate determination of energy savings gives facility owners and managers valuable feedback on their EE measures. This feedback helps them adjust the measure's design or operations to improve savings, achieve greater persistence of savings over time, and lower variations in savings.
- ***Improve engineering design and facility operations and maintenance***. The preparation of an M&V plan encourages comprehensive project design by including all M&V costs in the project's economics. M&V also helps managers discover and reduce maintenance and operating problems, so they can run facilities more effectively. M&V also provides feedback for future project designs.
- ***Document financial transactions***. For some projects, the savings are the basis for performance-based financial payments and/or a guarantee in a performance contract. A well-defined and implemented M&V plan can be the basis for documenting performance in a transparent manner and subjected to independent verification.
- ***Enhance financing for efficiency projects***. A well-executed M&V plan increases the transparency and credibility of reports on the outcome of energy-efficiency investments. It also increases the credibility of projections for the outcome of the investments. This credibility can increase the confidence that investors and sponsors have in EE projects, enhancing their chances of being financed.

- ***Support evaluation of EE programs***. Utility programs for managing the usage of an energy supply system can use M&V to evaluate the savings at selected energy user facilities. Using statistical techniques and other assumptions, the savings determined by M&V activities at selected individual facilities can help utilities predict savings at unmeasured sites in order to report the performance of the entire EE program. This, of course, is the reason why M&V is discussed in this chapter.

M&V Design and Reporting Process

The M&V design and reporting process involves the following steps:

1. Consider of the needs of the user of the planned M&V report(s). If the user is focused on overall cost control, whole-facility methods may be most suited (see Tables 12-4 and 12-5). If user focus is on particular EE measures, retrofit-isolation techniques may be most suited (see Tables 12-2, 12-3, and 12-5).
2. While developing the EE measures(s), select the M&V method that is most consistent with the scope of the measure(s), the needs for accuracy, and the budget available for M&V activities.
3. Gather relevant energy and operating data from the baseline period and record them in a way that can be accessed in the future.
4. Prepare an M&V plan containing the results of steps 1 through 3 above. The plan should define the subsequent steps 5 through 9 below.
5. As part of the final measure design and installation, also design, install, calibrate and commission any special measurement equipment that is needed under the M&V plan.
6. After the measure is installed, inspect the installed equipment and revised operating procedures to ensure that they conform to the design intent of the measure. This process is commonly called “commissioning.”
7. Gather energy and operating data from the reporting period, as defined in the M&V plan.
8. Compute savings in energy and monetary units in accordance with the M&V plan.
9. Report savings in accordance with the M&V plan.Overview of M&V Techniques

Energy and demand can be measured by one or more of the following techniques:

- Utility or fuel supplier invoices, or reading utility meters and making the same adjustments to the readings that the utility makes.
- Special meters isolating an EE measure or portion of a facility from the rest of the facility. Measurements may be periodic for short intervals, or continuous throughout the baseline or reporting periods.
- Separate measurements of parameters used in computing energy use and demand. For example, equipment operating parameters of electrical load and operating hours can be measured separately and multiplied together to compute the equipment’s energy use and demand.

- Measurement of proven proxies for energy use. For example, if the energy use of a motor has been correlated to the output signal from the variable speed drive controlling the motor, the output signal could be a proven proxy for motor energy.
- Computer simulation that is calibrated to some actual performance data for the system or facility being modeled. One example of computer simulation is DOE-2 analysis for buildings.

If the energy use or demand value is already known with adequate accuracy or when it is more costly to measure than justified by the circumstances, then measurement of energy may not be necessary or appropriate. In these cases, estimates may be made of some EE measure parameters.

There are four accepted methods for determining savings. The selection of which method to employ involves many considerations. Tables 12-2 through 12-5 summarize the four methods.

Table 12-2
M&V Method: Retrofit Isolation—Key Parameter Measurement

M&V Method	How Savings are Calculated	Typical Applications
Savings are determined by field measurement of the key performance parameter(s) which define the energy use and demand of the measure's affected system(s) and/or the success of the project. Measurement frequency ranges from short-term to continuous, depending on the expected variations in the measured parameter, and the length of the post-installation period. Parameters not selected for field measurement are estimated. Estimates can based on historical data, manufacturer's specifications, or engineering judgment. Documentation of the source or justification of the estimated parameter is required. The plausible savings error arising from estimation rather than measurement is evaluated.	Engineering calculation of baseline and post-installation period energy use and demand from: • short-term or continuous measurements of key operating parameter(s) • estimated values Adjustments are made as required.	A lighting retrofit where power draw is the key performance parameter that is measured periodically. Estimate operating hours of the lights based on building schedules and occupant behavior.

Table 12-3
M&V Method: Retrofit Isolation—All Parameter Measurement

M&V Method	How Savings are Calculated	Typical Applications
Savings are determined by field measurement of the energy use and demand of the affected system. Measurement frequency ranges from short-term to continuous, depending on the expected variations in the savings and the length of the post-installation period.	Short-term or continuous measurements of baseline and post-installation period energy use and demand, and/or engineering computations using measurements of proxies of energy use and demand. Adjustments are made as required.	Application of a variable speed drive and controls to a motor to adjust pump flow. Measure electric power with a kW meter installed on the electrical supply to the motor, which reads the power every minute. In the baseline period this meter is in place for a week to verify constant loading. The meter is in place throughout the post-installation period to track variations in power use.

Table 12-4
M&V Method: Whole Facility Measurement

M&V Method	How Savings are Calculated	Typical Applications
Savings are determined by measuring energy use and demand at the whole facility or sub-facility level. Continuous measurements of the entire facility's energy use and demand are taken throughout the post-installation period.	Analysis of whole facility baseline and post-installation period (utility) meter data. Adjustments are made as required.	Multifaceted energy management program affecting many systems in a facility. Measure metered energy use for a twelve month baseline period and throughout the post-installation period.

Table 12-5
M&V Method: Calibrated Simulation

M&V Method	How Savings are Calculated	Typical Applications
Savings are determined through simulation of the energy use of the whole facility, or of a sub-facility. Simulation routines are demonstrated to adequately model actual energy performance measured in the facility. This method usually requires considerable skill in calibrated simulation.	Energy use simulation, calibrated with hourly or monthly utility billing data. (Energy end use metering may be used to help refine input data.)	Multifaceted energy management program affecting many systems in a facility but where no meter existed in the baseline period. Energy use measurements, after installation of gas and electric meters, are used to calibrate a simulation. Baseline energy use, determined using the calibrated simulation, is compared to a simulation of post-installation period energy use.

Utilities can use information and results of M&V activities conducted by facility owners and other stakeholders as an important input to the impact evaluation of an EE program. A list of references provided at the end of this chapter offers greater details about how to select the proper M&V method and conduct the entire M&V process for any specific EE project.

Impact Evaluation Issues

Impact evaluations focus on the quantification of a number if issues related to the effects of EE programs. These include:

- ***Annual or Seasonal Energy Effects***. The change in energy use on an average annual or seasonal basis associated with participation in a program or installation of an EE measure.
- ***Load Shape Effects***. The changes in energy use and peak demand at specific times during the year.
- ***Persistence***. This measures the degradation over time of the EE savings. This includes the impacts of aging or poor maintenance and replacement of the measure before the end of its useful life.
- ***Rebound Effect*** (also "snapback" or "takeback" effect). Behavioral response by customers to increase energy equipment utilization when they upgrade efficiency. This phenomenon is associated with an effective decrease in the cost of the end-use services from efficient units.
- ***Variations in Timing and Program Features***. Understanding energy and load impacts by these dimensions is critical for extrapolating effects into the future and applying results for EE program and integrated resource planning.
- ***Gross Participation***. The number of customers who participated in the program. For purposes of comparison, gross participation is often expressed as a percentage of the eligible customer population.

- ***Free Riders***. Customers who participate in a program to get the incentives but undertake no incremental actions beyond what they would have undertaken without the program.
- ***Net Participation***. The number of customers who participated in the program beyond those that would have installed the measure of measures without the program. Proper estimation of this effect requires establishment of a control group of customers who do not participate in the program. New participation is equal to gross participation minus free riders.
- ***Market Penetration***. The number of equipment (e.g., fluorescent ballasts, water heaters) affected by the program. For purposes of comparison, market penetration is often expressed as a percentage of the eligible equipment population.
- ***Attrition***. Any pattern of customers dropping out of ongoing programs (e.g., an interruptible rate program).
- ***Equipment Supply Effects***. The direct and indirect effects that the level of program funding has on participation patterns, through its impacts on equipment suppliers, dealers, and installers.
- ***Secondary Measure Adoption***. Any measures that customers adopt outside of the program as a direct result of the promotion and incentives. For example, a customer purchases lighting measures beyond the maximum number eligible rebates.
- ***Interactions of Measure Adoption***. Propensity of customers to purchase certain combinations of measures. For Example, customers buy electronic ballasts and efficient lamps. This affects the saving from each measure.
- ***Free Drivers*** (or spillover effect). Customers who install program measures as a result of the program's effect on awareness or supply conditions but do not participate in the program.

Impact Evaluation Methods

Most impact evaluation methods fall into one or more of the following categories:

- ***Engineering Calculations***. Calculations of expected changes in energy consumption, peak demand, and load shape based on vendor-stated technical performance of EE measures and assumptions about operating patterns and conditions. Methods range from simple formulas to complex thermal load simulations. Figure 12-2 presents an example of a simple engineering calculation. This method is very similar to that discussed in the previous section on measurement and verification.
- ***End-Use Metering***. End-use loads are directly measured usually before and after installation of the EE measures to identify associated changes. This method is also very similar to that discussed in the previous section on measurement and verification.

An example of a simple engineering calculation to estimate the lighting savings illustrates the assumptions that are often required. Energy savings can be estimated as:

Energy Reduction = Demand Reduction X Operating Hours

The following issues arise in such an engineering calculation:

- It assumes no changes in service levels (e.g. lumens output, operation hours);
- It uses rated wattages to calculate the demand reduction;
- It requires assumptions about the wattages of replaced lamps;
- These is still a need to account for interactive affects across measures (e.g. lamps and ballasts; and
- There is still a need to account for secondary effects on other end-use loads (e.g. impact on space conditioning).

Figure 12-2
Engineering Calculation Example

- ***Statistical Analysis***. Statistical analysis of whole customer energy or load data to infer changes in usage associated with adoption of EE measures. Methods range from simple before/after comparisons between program treatment and control groups to applications of parametric statistical models (e.g., regression models). A program treatment group includes a sample of customers who participate in the program; a control group includes a sample of customers who do no participate in the program.
- ***Combined Engineering-Statistical Analysis***. For example, engineering-based estimates are used as explanatory variables in regression analysis of whole customer loads. Parameters verify the reasonableness of the engineering estimates or identify systematic biases. In another example, the duty cycle approach (discussed later in this chapter) is used for analyzing the impact of loads controls.

The relative advantages and disadvantages of each of these methods are summarized in Table 12-6.

Table 12-6
Strengths and Weaknesses of Impact Evaluation Methods

Method	Advantages	Disadvantages
Engineering Calculations	Conceptually straightforward, good representation of technology performance	Absence of behavioral effects; no empirical validation; can significantly overstate EE savings
End-Use Metering	Estimates based on direct measurement at end-use level	Most expensive method; difficult to obtain the baseline energy and demand conditions
Statistical Analysis	Based on recorded total usage (kWh or kW) data; suitable for examining variations by customer attributes	May yield implausible or ambiguous results; difficult to estimate impacts of individual measures
Combined Engineering-Statistical Analysis	Combines strengths of engineering and statistical approaches	Requires sophisticated analysis

Engineering Methods

Engineering methods include a family of approaches ranging from simple definitional relations to complex simulations of physical processes. These methods rely heavily on physical relationships and thermodynamics to estimate energy and load impacts. The technical coefficients in these relations are typically derived from laboratory test and field measurements. Equipment specifications and operating conditions are typically taken from manufacturers and design manuals. The engineering calculations are typically performed on averages or building prototypes. Engineering techniques are increasingly used in conjunction with statistical methods and field data.

Evaluators should recognize that engineering methods have different strengths and limitations relative to other approaches. Their strengths include:

- Intuitive appeal: changes in energy consumption are broken down into efficiency, operating hours, and capacity components;
- Detailed representation of technologies and their performance characteristics;
- Appropriateness for low-cost, “back-of-the-envelope” analysis;
- Well-understood and accepted formulas and algorithms; especially for dealing with end-use interactions (e.g. interaction between light and HVAC); and
- Easy comparison with EE planning studies which typically use engineering methods, as discussed in Chapter 5 and 8 of this report.

The limitations of engineering methods include:

- Little use of direct measurements for inputs;
- Difficulty of confirming validity of results and sources of biases from measured energy/load data;
- Poor representation of behavioral determinants of energy use/savings and consequent overstatement of EE savings. This problem can be mitigated if the engineering models are calibrated using some type of whole building data such as monthly billing data, or load research data for all hours of the month;
- Inadequate attention to the distribution of energy use across different types of customer and to load diversity consideration issues; and
- Require lots of data and specialized staff, and are expensive to run and update.

End-Use Metering

The second approach to evaluating program impacts is end-use metering. End-use metering as applied to program impact evaluation requires measurements of equipment that has been affected by EE measures. It is appealing because the impacts are based on direct measurements. However it is important to recognize that metering alone will not produce an estimate of the EE savings. Measured loads and energy consumption must be compared before and after program treatment. These comparisons must account for differences in operating conditions and other factors that influence equipment utilization. Some other issues associated with end-use metering include the following:

- Cost (meter and installation costs range from hundreds to tens of thousands of dollars per customer);
- Long-term versus short-term changes;
- Legal liability issues arising from possible malfunction of customer equipment;
- Impact on customer operations caused by the installation of meters;
- Isolating circuits affected by measures; and
- Is it necessary to obtain baseline data before installation of measures.

Given the various other issues affecting its application to impact evaluation, end-use metering is most effective in the following situations:

- Verification of savings from large-scale commercial/industrial measures on special circuits;
- Background research to estimate generic end-use loads;
- Measurement of internal loads, including lighting loads, for inputs to thermal load models; and
- Measurements of HVAC loads for calibration of thermal load models.

Statistical Analysis

Statistical approaches to program impact evaluation use billing data and whole-customer load research data from selected program participants and non-participants to estimate the savings attributable to the measures. Statistical approaches range from simple comparisons of average changes in consumption for participants and control samples to complex parametric modeling of the relation between energy demand and customer characteristics, measure adoption, program participation, and other variables. Some of these techniques are summarized below. For a complete discussion, see EPRI's Impact Evaluation of Demand-Side Management Programs, Volume 1 and 2 (CU-7179).

Billing Comparisons. Using bill comparisons is conceptually straightforward. It consists of making simple comparisons of treatment and control group bills before and after program participation. The differences in average changes between the two groups are attributed to the single factor that differs systematically between the two groups—namely, the effects of the program. Algebraically, this calculation is:

$$\text{Net Program Effect} = (E_{T,post} - E_{T,pre}) - (E_{C,post} - E_{C,pre})$$

where E is the effects of the program, T is the treatment group, and C is the control group.

Billing comparisons are appealing because they are conceptually simple and understandable. Standard t-statistics can be calculated to test for the significance of difference between the participant and control groups. However, external validity of the estimate of net program savings may be poor. If the attributes of participants or the mix of measurement installed under the program changes in the future, the estimates cannot be updated to accounts for their effects. Bill comparisons are often applied in conjunction with weather normalization of sales data in an attempt to improve the external validity of the estimates. In most applications, the control group is re-weighted or matched to the treatment group based on energy consumption in the pre-program period. This is an attempt to deal with the problem of bias arising from self-selection by participants.

Regression Analysis. Regression analysis is the other common statistical technique used to estimate program impacts. Regression analysis is concerned with causal relations between variable to develop average estimates of savings.

Regression analysis has several advantages over simple billing comparisons:

- Ability to control other, spurious effects (e.g. weather);
- Ability to identify impacts from individual measures;
- Ability to identify interactions among measure impacts;
- Ability to relate impacts to customer attributes;
- Ability to incorporate behavioral effects; and
- Under certain conditions, ability to function without usage data from a control group.

Combined Engineering-Statistical Analysis

Statistical models may not able to provide all the impacts estimates necessary for an evaluation (e.g. on-peak and off-peak savings in addition to the monthly savings estimated from a billing comparison). In addition, these models may not be able to provide estimates for all types of participants. Although engineering models are usually able to produce estimates of program savings for any time period that the utility selects and for most types of participants. Although engineering models are usually able to produce estimates of program savings for any time period that the utility selects and for most types of participants, they do not rely on actual in-field measurement of consumption. Thus, by combining statistical and engineering models the evaluator can take advantage of the strengths of each method.

In an integrated analysis, average estimates of savings produced by statistical methods can combined with engineering methods estimates to show how the hourly load curves change as a result of EE program action. As an example, a ratio calculated from engineering methods can be used to disaggregate the estimate of program savings from a monthly time period to alternate periods. This simple approach is illustrated by the following equation:

$$\frac{\text{On-Peak Savings (engineering models)}}{\text{Monthly Savings (engineering models)}} = \frac{X}{\text{Monthly Savings (statistical models)}}$$

where X is the estimate of on-peak savings to be used in cost-effectiveness analysis.

The duty cycle analysis is another approach that combines engineering and statistical methods. This approach is used to estimate the impacts of load control programs such as cycling of residential air conditioners. Engineering methods may estimate, for example, the demand savings associated with a typical air conditioner as 25 percent of the unit's connected load. However, air conditioners are not on all the time; statistical analyses of metered data may show that the average connected load is only 80 percent of the total connected load. Therefore, in this example the savings estimated through a combined engineering-statistical approach will be 80 percent of the savings estimated through the engineering method alone.

Impact Evaluation Case Study of an Energy-Efficiency Program

This section provides a case study of an actual impact evaluation that was conducted for an energy-efficiency program that was implemented in the state of New York.

The New York State Energy Research and Development Authority (NYSERDA) has operated the New York Energy $mart^{SM} Premium-Efficiency Motors Program since 1999. The Program is designed to increase the availability, stocking and sale of qualified premium-efficiency motors in New York State through a combination of vendor-based financial incentives; vendor education, training, marketing, and sales assistance; and an end-user information campaign on premium-efficiency motors. Eligible vendors include wholesale distributors, vendors, and dealers of electric motors, and original equipment manufacturers of equipment using qualified premium-

efficiency motors. Under the current incentive structure, vendors participating in the Program are eligible to receive between $25 and $80 per motor for selling qualified premium-efficiency motors. The exact incentive payment depends on which of three incentive schedules the vendors qualify for and this determination is based on their previous year's sales volume of qualified motors. Although the program is marketed primarily through vendors, NYSERDA staff also provides training seminars to end-users. Newsletters are also distributed to the vendors and end-users. Additionally, several other New York Energy $martSM programs, such as New Construction, Smart Equipment Choices and the New York Energy $martSM Loan Fund, work hand-in-hand with the Premium-Efficiency Motors Program to provide incentives to end-users for the installation of qualified motors in their facilities.

The accomplishments of the Premium-Efficiency Motors Program are tracked on a quarterly basis. As of the end of 2003, there were a total of 221 motor vendors participating in the Program. Also, participating vendors have sold a total of 7,992 motors and received incentives from the Program.

Objective of Evaluation

NYSERDA's implementation of the Premium-Efficiency Motors Program constitutes an investment of funds, and NYSERDA contracted third-party evaluators to conduct an impact evaluation that was designed to contribute to knowledge on the return from these investments and how these returns can be enhanced and reasonable expectations of future returns based on the Program's continuation. Specifically, the impact evaluation was preliminarily conducted in 2004 and was designed to focus on the following aspects:

- Market assessment in terms of tracking changes in the New York motors markets with a specific focus on market indicators that might be impacted by program activities; and
- Attribution/causality analysis that focuses on identifying the impacts of the program interventions beyond what would have happened without the program. Often termed measurement of "net impacts," this information is useful in making program decisions, including further investment, program exit decisions, and other policy and funding decisions.

Research Approach

A combination of primary and secondary data sources was used for this impact evaluation study. Primary data consisted of a variety of surveys targeted to vendors, end-users, and program implementation staff. The first primary data sources were telephone surveys to motor vendors in New York State. The vendor surveys were completed during the December 2003/January 2004 timeframe. A total of 34 participating vendor interviews were completed while only 4 non-participant vendor interviews were completed. Because NYSERDA has been so effective in reaching the motor vendor community through this program, most of the vendor respondents were from the pool of participating vendors. Out of the 34 participating vendors, roughly 27 (or 80%) were currently active in the program (according to the Program database) while the remaining 20% of respondents were considered inactive (i.e., they had not submitted invoices for the sales of qualifying motors).

The second primary data source was an end-user on-site survey, which was administered by NYSERDA's implementation contractor during the fourth quarter of 2003. As part of its ongoing implementation efforts, the implementation contractor maintains a database of end-user contact information for every 20th motor incented by the program. The implementation contractor used this database to conduct a survey of the end-users who purchased a motor for which a vendor incentive was provided. A total of 83 end-user surveys were completed during this timeframe. The evaluator was able to extract some findings that served as evidence for attributing several market effects to the Premium-Efficiency Motors Program.

The third primary data source was a survey of NYSERDA staff and implementation contractors related to the Premium-Efficiency Motors Program. This survey was conducted in order to augment the limited information available for use in the attribution and causality analysis. A total of 5 surveys were administered to this group.

A number of secondary data sources including a variety of recently-completed New York-specific reports and studies related to premium-efficiency motors were also used by the evaluator.

Findings

The third-party evaluation contractor uncovered several interesting findings concerning NYSERDA's Premium-Efficiency Motors Program during its preliminary work in 2004. The following points summarize the evaluator's findings:

- Participating motor vendors reported that approximately 41% of all 3-phase AC motors (between 1-200 HP) they sold during the past 12 months qualified as NEMA Premium™ motors. This figure is slightly lower than that found in a previous market study, which reported that 50% of all 3-phase AC motors sold by vendors meet the CEE standards. However, this comparison brings attention to one significant problem with trying to compare current figures with those from 2001: NYSERDA now promotes NEMA Premium™ motors, but in 2001, NYSERDA promoted motors that meet the CEE standards. Since the two motor efficiency standards are different, the evaluator believed that this may lead to situations where one is comparing "apples and oranges", and comparisons between data sets based on two different standards may not be completely valid.
- The vendor survey results show that the Premium-Efficiency Motors Program has increased participating motor vendors' level of awareness and knowledge of NEMA Premium™ motors. For instance, 56% of 34 total respondents reported that they now have "excellent knowledge" since joining the Program, which is much larger than 15% of respondents that reported having "excellent knowledge" prior to joining the Program.

- The vendor survey also shows that many participating vendors believe the Premium-Efficiency Motors Program has had a positive influence on their firms and their customers. For instance, when asked to rate their level of agreement with the statement claiming that the Program has increased their firm's knowledge of NEMA Premium™ motors, 54% of respondents reported that they either "agree" or "strongly agree" with this statement. Similarly, when presented with the statement claiming that the Program has increased their customers' knowledge of the benefits of NEMA Premium™ motors, 57% of respondents indicated that they either "agree" or "strongly agree" with this statement. Additionally, 57% of respondents reported that their sales staff currently informs their customers about NEMA Premium™ motors either "in all situations" or "in most situations."
- The vendor survey results suggest that the Premium-Efficiency Motors Program motivated many vendors to promote and sell NEMA Premium™ motors. For example, 85% of active vendors indicated that the availability of financial incentives provided by NYSERDA had either a "moderate" or "significant influence" on their motivation and ability to sell NEMA Premium™ motors. Furthermore, 69% of active motor vendors indicated that the training and sales assistance activities provided by NYSERDA had either a "moderate" or "significant influence" on their motivation and ability to sell NEMA Premium™ motors.
- However, the survey results also indicate that the vendors' participation in the Program only had a marginal effect on actual sales of NEMA Premium™ motors: 35% of active vendors indicated that about three-fourths of their sales of NEMA Premium™ motors would have been sold anyway, and 31% of active vendors indicated that all of their sales of NEMA Premium™ motors would have been sold regardless of their participation in the Program. However, these findings can be misleading because, on the surface, they suggests a high level of free-ridership in the Premium-Efficiency Motors Program when in fact there are other NYSERDA programs that provide market "pull" to increase end-users' demand for NEMA Premium™ motors in parallel to the Program. From the vendors' perspective, it may seem that end-users are already demanding NEMA Premium™ motors when in fact other NYSERDA efforts are providing a significant influence in creating that demand. In conclusion, the evaluator found that although many participating vendors believe the Premium-Efficiency Motors Program has had a positive influence on their motivation and ability to sell NEMA Premium™ motors, which was a major focus of the Program, the evaluator speculated that the vendors also believe that market forces such as consumer demand would have driven them to sell many NEMA Premium™ motors regardless of their participation in the Program.
- In light of other clear evidence indicating the Program has increased knowledge and awareness of NEMA Premium™ motors, the evaluator believed that the vendors may be underestimating the influence of the Program on their sales. This conclusion is supported by the fact that 78% of participating vendors reported that they agree with the following statement: "My firm's sales of NEMA Premium™ motors have increased since joining the Program." Furthermore, 24% of participating vendors reported that their sales of NEMA Premium™ motors has increased during the past 12 months, and the reason for this increase was often cited as the presence of the Program. Sixty percent of participating vendors also indicated that their sales of NEMA Premium™ motors would be impacted if the Program were to be discontinued. These evidences support the evaluator's conclusion that the vendors are underestimating the influence of the Program on their sales.

- An important finding derived from the implementation contractor's onsite survey of end-users is that motor vendors continue to be the channel by which end-users become aware of NEMA Premium™ motors. An analysis of the survey results found that 54 out of 79 (68%) end-users who installed a NEMA Premium™ motor first became aware of the NEMA Premium™ motor through a motor vendor. The next closest method of learning about NEMA Premium™ motors is through communication with other industry colleagues (13%).
- There is evidence that motor vendors are able to persuade facility owners/managers to purchase NEMA Premium™ motors. The implementation contractor's onsite surveys of installed NEMA Premium™ motors found that the facility owner/manager of 10 out of 60 (17%) installations had considered a lower-efficiency motor before choosing to purchase a NEMA Premium™ motor. The facility owners/managers of the remaining 50 out of 60 (83%) installations reported that they were already considering a NEMA Premium™ motor even before their motor vendors recommended it.
- Several of NYSERDA's other end-user programs provide incentives for the purchase of NEMA Premium™ motors. However, there is evidence that facility owners/managers are willing to purchase and install NEMA Premium™ motors without receiving any financial incentives. The implementation contractor's onsite surveys found that only 14 out of 50 (28%) facility owners/managers that have installed a NEMA Premium™ motor received some sort of financial incentive from NYSERDA. Four facility owners/managers reported receiving incentives from the Smart Equipment Choices Program, and two reported receiving incentives through the Commercial and Industrial Performance Program for the NEMA Premium™ motors installed at their facilities. The remaining 8 facility owners/managers did not indicate which other NYSERDA programs provided them with incentives. Five (5) out of 6 facility owners/managers reported that receiving a financial incentive from NYSERDA had influenced their decision to install the NEMA Premium™ motor (the remaining eight did not comment). In addition to financial incentives from other NYSERDA programs, it is highly possible that vendors may have played an important role in influencing facility owners/managers to install the NEMA Premium™ motor, since 54 out of 79 (68%) of respondents indicated that they became aware of NEMA Premium™ motors through motor vendors.
- The implementation contractor's onsite survey of end-users also asked the following question: "Since buying this motor have you made other energy-efficiency improvements?" Although 51 out of 68 (75%) end-users indicated that they have made other energy-efficiency improvements, such as variable speed drives, lighting and HVAC upgrades, there appears to be no quantifiable evidence of a spillover effect that can be strongly attributed to the Program. There is preliminary evidence that there could be a large spillover effect, however the evaluator was unable to fully quantify the spillover effect based on the available information. Also, other energy-efficiency improvements conducted by end-users may be due to other NYSERDA end-user incentive programs in addition to the Premium-Efficiency Motors Program.
- Using a combination of primary and secondary data findings as stated above, the evaluation contractor derived a preliminary free ridership rate of 30% and a spillover rate of 10% for the Premium-Efficiency Motors Program. Using these figures, the evaluator estimated that the net energy savings of the Program was 5,484 MWh, and the net demand savings of the Program was 1,096 kW.

Summary and Resources

This chapter has described the issues associated with the evaluation of EE programs. The evaluation methods used to conduct process and impact evaluations have also been described. Recommended reference materials and resources for additional insights into the topics discussed in this chapter are listed below.

Resources

Measurement and Verification

International Performance Measurement and Verification Protocol, Volumes I, II, and III, prepared by the Efficiency Valuation Organization, April 2007.

M&V Guidelines: Measurement and Verification for Federal Energy Projects, Version 2.2, prepared by Schiller Associates for the U.S. Department of Energy, September 2000.

Measurement of Energy and Demand Savings, ASHRAE Guideline 14-2002, prepared by the American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE), 2002.

2005 Standard Performance Contract Procedures Manual, administered by Pacific Gas and Electric Company, San Diego Gas and Electric, and Southern California Edison, April 2005.

Energy Efficiency

A Framework for Planning and Assessing Publicly Funded Energy Efficiency, for Pacific Gas and Electric Co, by Regional Economic Research, Inc., Skumatz Economic Research Associates, Inc., Shel Feldman Management Consulting, Xenergy, Inc., Research Into Action, Inc. March 2001.

Evaluation of the Energy Trust of Oregon's New Building Efficiency Program- Final Report. Submitted to: Energy Trust of Oregon. Submitted by: Nexus Market Research, Inc., Heschong Mahone Group. August 26, 2005

New York ENERGY $MART Program Evaluation and Status Report, Vol. 2, New York State Energy Research and Development Authority, 316 pp., Report 376, May 2004.

Standardized Methods for Free-Ridership and Spillover Evaluation—Task 5 Final Report, for National Grid, NSTAR Electric, Northeast Utilities, Unitil, Cape Light Compact. June 16, 2003

The California Evaluation Framework, prepared for Southern California Edison Company, by TecMarket Works Framework Team, TecMarket Works. June 2004

Demand Response

2004 Smart Thermostat Program Impact Evaluation, prepared for San Diego Gas and Electric Company; by KEMA. February 2005.

Assessment of Demand Response and Advanced Metering- Staff Report, FERC Docket AD06-2-000; August 2006

Demand Response Analysis and Tool Development for Industrial, Agricultural and Water (IAW) End Users- Appendix 2: Assessment of Demand Response Programs - Literature Review. EPRI Palo Alto, CA: 2005

Demand Response Resources (DRR) Valuation And Market Analysis: Assessing DRR Benefits and Costs, by Daniel M. Violette and Rachel Freeman, Summit Blue Consulting, 2006.

Phase 1 Results: Incentives and Rate Design for Energy Efficiency and Demand Response; by Orans, Ren et al. Energy and Environmental Economics. DRRC Report, LBNL-60133 Collaborative Report. April 2006

Program Impact Evaluation of the 2004- SCE Energy Smart Thermostat^{SM} *Program*, prepared for Southern California Edison by RLW Analytics. January, 2005.

Revealing the Value of Demand Response: Regulatory & Market Options, EPRI, Palo Alto, CA: 2003. 1001638.

13
ROLE OF ENABLING TECHNOLOGIES

Introduction

Technology plays a key role in enabling demand side resources. Without enabling technologies, it would not be possible to achieve savings in electricity use and peak demand. The future growth of the energy efficiency and demand response market capability depends on the technologies' cost and functionality. This chapter presents technology options that can achieve savings in electricity use and peak demand.

Energy-Efficient Technology Options

A wide variety of energy-efficient technologies are commercially available. Many common residential energy-efficient technologies were presented in Table 6-1 of Chapter 6. Table 13-1 shows examples of technology options that are applicable to buildings and industries.

Table 13-1
Examples of Energy-Efficient Technologies

Buildings		Industry	
Building Shell	Insulation Double- or triple-pane window Low-emissivity window	Motors	High efficiency motor Variable speed drive Multi-speed motor
Cooling	High-efficiency central air conditioner Evaporative cooler High-efficiency room air conditioner Attic venting	Boilers	Firing rate demand controller Blowdown optimization Economizer heat recovery
Heating	Variable-speed furnace Active solar space heater Two stage condensing gas furnace Electrically-heated floor	Process Heating	Microwave Induction Infrared UV curing
Cooling & Heating	Smart thermostat Heat pump for space conditioning	Waste Treatment	Microwave waste treatment Dry heat waste treatment Chemical waste treatment
Lighting	High-efficiency fluorescent lamp and ballast Compact fluorescent lamp LED exit sign Occupancy sensor Daylighting controls	Air & Water Treatment	Ozonation UV Photocatalytic oxidation
		Membrane Separation	Reverse osmosis Microfiltration

Table 13-1 (continued)
Examples of Energy-Efficient Technologies

Buildings		Industry	
	Dimming controls		
Water Heating	High-efficiency water heater	Food and Agriculture	Variable speed vacuum pump
	Solar water heater		Agriculture ventilation fan
	Heat pump water heater		Ultra high pressure food processing
	Tankless water heater		Irradiation of food products
Appliances			High efficiency refrigeration
	High efficiency refrigerator	General	
	High efficiency appliances		Energy management and controls system
	Refrigerator or freezer antisweat switch		Advanced control and power technologies
	High efficiency electronic devices		

Many of the technologies listed in Tables 6-1 and 13-1 are well-known and a large volume of information on these technologies are available in literature. At the end of this chapter is a list of references that provide more information on energy-efficient technologies.

The objective of the following sections is to provide a summary of a selection of advanced technology options that are expected to be important in enabling savings in electricity use in the future. Many of the technologies described in the following sections are new and innovative, and some are still under development. For each technology, a general description is provided, and applications and status are identified.

Advanced Lighting Technologies

The following lighting technologies are described in this section:

- Induction Lighting
- Full Spectrum/Scotopic Lighting
- Daylight Harvesting /Pipe Lighting
- White Light-Emitting Diode (LED) Lighting
- Integrated Classroom Lighting
- Motion Sensor Nightlight
- T5 Fluorescent Lamps
- Multi-Photon Emitting Phosphor Lighting

Induction Lighting

Description: Induction lamps, like fluorescent lamps, employ discharge technology. That is, they elevate the energy level of mercury or other atoms, which then discharge a photon as they return to their normal energy level. However, induction lamps differ from fluorescent lamps in the way they energize the mercury atoms. Instead of striking an arc between electrodes, an electromagnetic field is generated by a carefully shaped coil. The field created by the coil induces a current flow in the gas/mercury blend within the lamp. This current excites the mercury atoms and starts the flow of UV photons, which strike phosphors lining the lamp wall and in turn emit visible photons. Like high-quality fluorescents, induction lamps offer instant strike, instant restrike, color stability, 80+ color rendering index, high power factor, and low THD. A ballast — called a field generator — is required to provide the power electronics that drive the induced current in the lamp. Induction technology is not dimmable at this time, but it could be in the future.

Benefits: Two important benefits result from the application of this technology:

- Energy savings. Energy savings will depend upon the type and wattage of the lamps being replaced. Typical energy savings will be between 20–50%.
- Longevity. Lamp life is estimated to be 100,000 hours, which is several times greater than other types of lamps.

Applications: Commercial lighting. Because of their longevity, they are ideal for use in hard-to-reach locations, such as high ceilings.

- Auditoriums
- Gymnasiums
- Retail
- Warehouses
- Outdoors/Streets/Parking lots

Status: Commercially available. GE, Philips, Osram Sylvania, and Matsushita all have technologies on the market. However, market penetration has been limited to this point.

Full-Spectrum/Scotopic Lighting

Description: Scotopic lighting involves enhancing the blue-green spectrum of light to improve vision and brightness. The retina contains two types of photoreceptors, cones and rods, which are each receptive to different wavelengths of light. Cone activated vision is referred to as photopic; rod activated vision is termed scotopic. Blue-green wavelengths cause pupils to contract. Therefore, by utilizing a full-spectrum or scotopically enhanced light source, a person perceives an area to be brighter. By this token, shifting the lamp color of light toward higher scotopic content could compensate for a reduction in photopic lumens, thereby resulting in considerable energy savings.

Benefits: Energy savings. Energy savings depend on the type of scotopic lamp used, and the type and quantity of lamps it replaces. For example, fixtures consisting of four F34 T12 lamps with a color temperature of 3000K and energy-saving electromagnetic ballasts could be replaced with two F32 T8 lamps with a color temperature of 5000K and electronic ballasts. This replacement would increase brightness perception and reduce power from 144W to 62W per fixture—a 57% energy savings not including reduced cooling load.

Applications: Commercial lighting. The technology is most applicable to commercial lighting applications where work focus is on computers and reading, such as office buildings and schools.

Status: Commercially available. While the technology is on the market and there has been research on its impacts, guidelines from the lighting design industry for applying the technology are not available.

Daylight Harvesting/ Pipe Lighting/Solar Light Tubing

Description: Daylight harvesting takes advantage of available daylight to augment electric lighting systems. One approach is to use dimming ballasts and strategically located photoreceptors to measure the changing contribution of free natural daylight to a desired user-programmed level of light in a room. This equipment can automatically dim or brighten the fluorescent lighting they control, adding only as much artificial light as needed to maintain that programmed level precisely. The result is a seamless blending of light sources that goes virtually unnoticed by the room's occupants. It delivers greater energy cost reductions than dimming only systems. The more usable daylight entering the space, the more the electric lights can be dimmed, resulting in significant energy savings.

Another approach is to use pipe lighting or solar light tubing is a form of tubular skylight that allows for daylight harvesting. Pipe lighting systems consist of tubes mounted on the roof that collect and pipe natural daylight into a room where it is bounced around surfaces. More advanced pipe lighting systems (e.g., Solatube) capture light through a dome on the roof and channel it down through internal reflective systems featuring optic enhancement devices. A diffuser located at the ceiling spreads the light evenly throughout the room. Such advanced pipe lighting systems provide higher light output because they capture more light, from all angles, and reflect the light down the tube. These systems work well even during early morning, late afternoon, or in the winter months when the sun is low on the horizon. Pipe lighting systems require less space than conventional skylights.

Benefits: Six benefits result from application of daylight harvesting and pipe lighting technologies:

- Energy savings. Daylight harvesting systems can reduce lighting energy use by 30 to 60% and result in payback periods of four to five years or less. Pipe lighting replaces a portion of artificial lighting. Energy savings will depend upon the type and Wattage of the lamps being replaced.

- Efficacy. Pipe lighting is more efficient than the traditional drywall skylight shaft, which can lose over half of the potential light. Additionally, instead of lighting only the space directly below the skylight, pipe lighting systems use optics to spread the light out, often lighting the entire room.
- Convenience. Daylight harvesting systems are designed to maintain a programmed light level automatically.
- Light quality/appearance. Daylight harvesting and pipe lighting provide natural light, which is known to reduce eyestrain, improve color rendering, and provide a greater sense of wellbeing among building occupants. It can also make spaces appear larger.
- Form factor. Pipe lighting systems are compact in design and feature adjustable tubing with angle adapters that allow for installation around attic obstructions. Pipe lighting systems can also be installed in places where a traditional skylight would not be an option, such as rooms without direct roof access or small areas like bathrooms, closets, and hallways.
- Integrated lighting and ventilation. Pipe lighting systems can be integrated with electric lights (for nighttime lighting) or ventilation fans, providing several functions from one single ceiling fixture.

Applications: Daylight harvesting is applicable to all areas of a commercial building subject to natural daylight, such as perimeter rooms and atriums. Pipe lighting systems are applicable to residential and many commercial building types.

Status: Commercially available. Pipe lighting systems are available at most home improvement stores. Penetration of daylight harvesting systems has been low due to difficulties in modeling energy savings and high costs.

White Light-Emitting Diode (LED) Lighting

Description: One way to produce white LEDs is to start with a blue or ultraviolet (UV) LED and then use phosphors to absorb UV photons and emit photons of other colors. Another way to produce white light is to use a combination of single-colored LEDs, thereby eliminating the efficiency loss associated with phosphors. Still another technique, which is still very novel, is to produce white light with organic LED (OLED) technology. OLEDs employ organic materials that respond to a current flowing through them. The current excites electrons, and as the electrons return to their original energy states, they emit visible light.

Benefits: Five benefits result from application of this technology:

- Efficacy. Current white LEDs have energy efficacies of 30 to 60 lumens per Watt, which is between incandescent lights, at about 10 to 23 lumens per Watt, and fluorescent lights, at about 60 to 100 lumens per Watt. Further development will continue to improve efficacy.
- Longevity. Current LEDs have a useful life of about six times that of incandescent lights. Their long life reduces the maintenance and expense involved with replacing lamps, and makes them optimal in applications where it is difficult or inconvenient to replace lamps often.

- Light quality/appearance. White LEDs and OLEDs have the potential to improve light quality and appearance over conventional lamps, especially in niche applications such as in displays or signage.
- Form factor. The very small size of LEDs enables their use in a variety of form factors.
- Robustness. LEDs operate well in cold environments and can withstand vibration and shock.

Applications: White LEDs are applicable for all building types. Specific applications include general indoor lighting, task lighting, architectural lighting, outdoor lighting, flashlights, display lighting, entertainment/information lighting, elevators, street lighting, automotive lighting, refrigerator lighting, airplanes, airports, and lighting for electronic devices.

Status: Commercially available. White LEDs for area lighting, refrigerated case lighting, and signage are now available, however costs are still very high.

Integrated Classroom Lighting

Description: This integrated system combines a novel 96-97% reflective fixture material with high-efficiency fluorescent bulbs and controls for daylighting, occupancy, and dimming. The end result is a plug-and-play system in which the customer relies on one source for the layout, pricing, installation, support, and maintenance. Preliminary demonstrations of the system are currently being carried out in six different California schools as part of the PIER Lighting Research Program. For the classroom demonstrations, the lighting consists of two or three 24-ft rows of fixtures. Each fixture has three T8 fluorescent lamps. Two of the lamps per fixture are directed upward for indirect, general classroom lighting, and the third is directed downward for reading and/or audio/video presentations.

Benefits: Four benefits result from application of this technology:

- Energy savings. For a typical classroom environment, the power requirements are 0.35 W/sq ft for one-light operation (direct lighting) and 0.70 W/sq ft for two-light operation (indirect lighting). Energy savings are 30 to 50% over conventional systems.
- Increased natural lighting. The system incorporates daylighting controls; enabling dimming of the artificial lights when natural light is available.
- Convenience. The system is designed to be very easy to operate (“plug-and-play”).
- Comfort/productivity. The system offers high-quality light, thereby improving comfort and productivity in the classroom.

Applications: Commercial lighting. The system is designed specifically for classrooms, but has also been used in offices and hospitals.

Status: Commercially available. While the technology is on the market, penetration has been low due to difficulties in modeling energy savings and high costs. In addition, guidelines from the lighting design industry for applying the technology are not yet available.

Motion Sensor Nightlight

Description: A lighting system that combines energy-efficient fluorescent lamps for the main light source with a wall-mounted switch faceplate containing light-emitting diodes (LEDs) for use as a nightlight when the main light is turned off, or as a safety light during power outages. The faceplate is also equipped with a motion sensor to turn off the main light after a pre-determined length of time with no activity in the room. In addition, a rechargeable battery powers the LEDs when the main light turns off.

Benefits: Three benefits result from application of this technology:

- Safety. The automatic LED motion sensor nightlight provides illumination in the nighttime and during power outages. This helps reduce trips and falls by people trying to find their way to the bathroom.
- Efficiency. The motion sensor shuts off the main fluorescent light when no activity is present in the room. This automatic feature reduces energy consumption. This may be of particular interest to hotels, where people often leave the bathroom light on during the evening.
- Improved vision. The LED light is subtle, making it easier for eyes to adjust to the light during the evening.

Applications: Commercial and residential lighting. The manufacturer of this technology markets it primarily towards hotel bathroom applications. Other potential applications include assisted living facilities, hospitals, and residential homes.

Status: Commercially available. High costs have kept this technology from higher market penetration.

T5 Fluorescent Lamps

Description: T5 lamps are fluorescent lamps that are thinner (5/8-inch diameter) and more efficient than both T12 (1 1/2-inch diameter) and T8 (1-inch diameter) lamps. In spite of their higher efficiency, they have not reached their full market potential because they are available only in metric sizes. The length of the T5 lamp nearest to that of a standard 48-inch T12 or T8 lamp is about 46-inches long. As a result, they have not been used as direct replacements for the less efficient lamps. High-output (HO) versions of T5 lamps have found favorable evaluations as replacement for HID (high intensity discharge) lamps in warehouses, gymnasiums, and other high-bay areas. This is because there is no restrike time for T5 lamps, meaning that they can be switched off (either manually or by the use of occupancy sensors) when an area is unoccupied.

Benefits: Two benefits result from application of this technology:

- Efficacy. T5 lamps provide greater light output (measured in lumens) per Watt of energy input than both T8 and T12 lamps.
- Light quality/appearance. T5 lamps provide higher-quality illumination than HID lamps in warehouse or other high-bay areas, because the shadows they cast are not as deep.

Applications: Luminaires for T5 lamps are appropriate for commercial applications. A particularly good application is indirect lighting, due to the higher intensity output of the T5. Another increasing popular application is as a retrofit for HID lighting in warehouses, gymnasiums, and other high-bay areas.

Status: Commercially available. Due to their metric lengths, applications of T5 lamps have been limited until recently to new construction and renovations. New products are available that allow the retrofit of 48-inch T8/T12 lamps with T5 lamps, but no literature on the performance of these products is available.

Multi-Photon Emitting Phosphor Lighting

Description: Fluorescent lamps consist of a sealed glass tube containing a small amount of mercury vapor, some low-pressure inert gases (usually argon), and an electrode at each end of the tube. The inside of the tube is coated with a phosphor. Phosphors produce visible light when excited with ultraviolet (UV) radiation. Voltage applied across the electrodes initiates gas discharge – atoms are excited in the gas. As the atoms change from the excited state to the unexcited state, they release UV photons. The phosphor acts to convert the UV radiation into photons of visible light. The spectrum of light produced is a function of the types of phosphors employed.

Current research indicates that the multi-photon emitting phosphor technology has the potential to double the quantity of lumens achieved per radiant Watt in discharge lamp applications. The luminous efficacy of the most efficient fluorescent lamps currently available commercially is on the order of 100 lumens per Watt. The goal of multi-photon phosphor development is to increase the luminous efficacy of commercially applicable lamps to 200 lumens per Watt.

By definition, multi-photon emitting phosphors produce on average more than one visible photon for every incident ultraviolet photon. These phosphors are also referred to as quantum splitting phosphors. The effectiveness of the multi-photon emitting phosphor technology is a function of several parameters, including the type of phosphor, sensitizer, and host employed. The most effective combinations of these variables have yet to be identified.

Benefits: The multi-photon emitting phosphor technology may have the potential to achieve significant energy savings over the most efficient lighting currently available for general lighting applications.

Applications: The technology is applicable to all types of fluorescent lighting systems.

Status: Under development. The technology is still in the development stages for discharge lamp applications, and several technical and practical barriers must be overcome before the technology will be commercially viable. Under contract to the U.S. Department of Energy (DOE), the Electric Power Research Institute (EPRI) and Osram-Sylvania, Inc. recently completed a feasibility study that detailed the status of the technology and recommended future steps to further development. Though the multi-photon phosphor area appears to have great long-range promise, it is likely it will take several years for the technology to be more fully developed for fluorescent lighting applications. The level of development will depend on how much is invested

by the government and/or lighting companies. Currently, there is not a lot of activity in multi-photon emitting phosphor research.

Advanced HVAC Technologies

The following HVAC technologies are described in this section:

- Series Desiccant Wheel
- Condenser Heat Reactivated Desiccant
- Smart Thermostats
- Demand-Controlled Hybrid Ventilation
- Dedicated Outdoor Air Systems (DOAS)
- Indirect/Hybrid Evaporative Cooling
- Active Magnetic Regenerative (AMR) Cooling

Series Desiccant Wheel

Description: The series desiccant wheel is installed in the air handling unit (AHU) where it boosts the capacity of the cooling coil, increasing moisture removal. Moisture from the air leaving the cooling coil is captured in the top part of the wheel and then transferred to return air that goes through the lower part of the wheel. It is different from an enthalpy wheel in that it does not transfer energy between the exhaust stream and outdoor air stream. Instead, the wheel transfers the latent load from air exiting the cooling coil and passes it through the cooling coil again.

Benefits: Two primary benefits result from application of this technology:

- Improved dehumidification. The series desiccant wheel can enable the air leaving the AHU to have a dew point that is 5 to 15 ºF lower than the air leaving the coil, thus improving the dehumidification ability of the coil. According to Trane, the wheel can remove 20 to 300% more water from the air than a standard coil, particularly under part-load conditions.
- Efficiency. The technology increases energy efficiency by reducing the energy required for reheat and cooling. According to Trane, the wheel reduces the annual operating costs by 50% in comparison to cool and reheat using one coil, is more energy efficient than cool and reheat using two coils or split dehumidification units, and is much more energy efficient than gas regenerated desiccants.

Applications: Commercial and industrial humidity control. Applicable to buildings requiring humidity control. Example applications include hospital operating rooms, schools, dry storage, museums, courthouses, processing plants.

- Offices
- Schools
- Hospitals

- Retail
- Restaurant
- Warehouses

Status: Commercially available. It appears that only Trane is currently marketing this technology (under the name CDQ™ — "Cool, Dry, Quiet").

Condenser Heat Reactivated Desiccant

Description: The technology dehumidifies ventilation air with a desiccant that is regenerated with recycled condenser heat. It merges the benefits of desiccant dehumidification with direct expansion (DX) air conditioning and enables humidity and temperature to be controlled independently of each other.

Benefits: Three primary benefits result from application of this technology:

- *Improved occupant comfort*. The humidity control unit (HCU) controls humidity separately from temperature. Conventional air conditioning systems rely on the cooling process to dehumidify the air. However, when the latent load (humidity) is high relative to the sensible load (temperature), conventional systems may not adequately dehumidify the air, or they may cause the temperature to be too low, both of which cause occupant discomfort and complaints.
- *Efficiency*. The HCU unit is more energy efficient than traditional DX-only systems that overcool and reheat the air in order to achieve acceptable humidity and temperature levels. According to developers, the unit has a coefficient of performance of up to 65% higher than standard air conditioning systems, and can lower energy operating costs by as much as 40%. It is also more efficient than desiccant systems that incorporate separate gas heaters to regenerate the desiccant.
- *Reduced risk of mold*. Better humidity control help protects building owners and operators from the liabilities associated with mold growth.

Applications: Commercial humidity control. This technology is appropriate for a wide range of commercial building types, including:

- Schools
- Restaurants
- Convenience stores
- Supermarkets
- Hotels and motels
- Hospitals
- Theaters
- Offices

Status: Commercially available. This technology is made by several manufacturers and is widely available for any of the applications listed.

Smart Thermostats

Description: Smart thermostats can be programmed to set back or set forward the temperature depending on the time of day and day of week. By eliminating the need for manual control, they ensure that the settings will indeed be changed, whereas manual resetting of thermostats depends on occupant diligence. Some utilities have set up load control programs in which they can also communicate with smart thermostats and turn them down (or up) during high peak periods.

Benefits: Three primary benefits result from application of this technology.

- Energy savings. A general rule of thumb is that for every 1 degree of thermostat setback (heating) or set-forward (cooling) during an 8-hour period, there is a 1% savings in annual heating or cooling energy costs. (The energy savings are generally lower in more severe climates). Utility companies can also communicate with smart thermostats to set back temperatures during peak demand periods.
- Convenience. Automated controls offer convenience to the user.
- Comfort. When occupied, the space is automatically maintained at comfortable levels defined by user.

Applications: This technology is appropriate for any type of commercial building with space conditioning, including:

- Schools
- Restaurants
- Food stores
- Hotels
- Hospitals
- Auditoriums
- Offices

Status: Commercially available. This technology is made by many manufacturers and is widely available for any of the applications listed in a broad range of control types, designs, and features.

Demand-Controlled Hybrid Ventilation

Description: Hybrid ventilation is not a new technology; however it has received renewed interest, especially in Europe, because of its potential to improve indoor air quality while reducing energy consumption. A demand-controlled hybrid ventilation system relies on natural ventilation, through windows and/or wall vents, when outside conditions allow it, and mechanical ventilation using electrical fans only when the inside conditions require ventilation

and the outside conditions are not favorable. The demand for mechanical ventilation is usually determined by temperature and carbon dioxide sensors, and sometimes also by occupancy sensors. Outside air intake is normally located in the building facade or atrium, but may also be brought in through underground culverts (a Norwegian approach that allows for preheating). In 2002, the European Union started a new project, RESHYVENT, on demand-controlled hybrid ventilation in residential buildings with emphasis on the integration of renewables.

Benefits: Three benefits result from application of this technology:

- Energy savings. The use of natural ventilation reduces demand on mechanical ventilation systems.
- Improved indoor air quality. Increasing outside air ventilation improves indoor air quality.
- Convenience. The systems are automated, offering convenient operation.

Applications: Commercial and residential space conditioning and indoor air quality. This technology is particularly well-suited for buildings where large numbers of occupants congregate for irregular periods of time or for large, underused spaces.

- Schools
- Restaurants
- Food stores
- Hotels
- Hospitals
- Auditoriums
- Offices
- Residential

Status: Commercially available. This technology is typically offered as an optional control component on factory-built HVAC systems. They are also realizing increasing adoption as control system retrofits.

Dedicated Outdoor Air Systems (DOAS)

Description: Most conventional HVAC systems distribute re-circulated indoor air combined with fresh ventilation air from outside through a duct system to the different parts of a building. These systems are designed to control both room temperature (the "sensible load") and humidity (the "latent load") while providing sufficient fresh outside ventilation air to dilute pollutants generated by building occupants and equipment. However, in humid climates, the ventilation air brings with it additional humidity, which is not wanted in the building.

A DOAS controls the humidity of the incoming fresh outside air, thus providing the needed ventilation air without the additional latent load. It accomplishes this by keeping the flows of re-circulated indoor air and ventilation air separate.

A DOAS reduces energy consumption in a number of ways. First, ventilation air energy consumption is reduced by decreasing the total ventilation airflow needed to meet ventilation requirements. Second, reductions in ventilation airflow decrease the energy expended to condition the outside air during cooling and heating seasons. Lastly, because the outside air is separately conditioned from the internal loads, with the entire building humidity load handled in the process, the re-circulated indoor air conditioning system can be operated to maintain temperature control. This enables the use of higher chilled water temperatures for the internal (sensible) loads, increasing the COP of the air conditioner compressor.

Benefits: Four benefits result from application of this technology:

- Energy savings. The use of DOAS reduces energy use necessary to condition the incoming fresh air.
- Improved indoor air quality. A DOAS helps avoid moisture-related indoor air quality problems.
- Improved occupant comfort. Better control of the ventilation air humidity improves occupant comfort and it also helps avoid over cooling, which is another cause of occupant discomfort and complaints.
- Reduced risk of mold. Better humidity control help protects building owners and operators from the liabilities associated with mold growth.

Applications: Commercial humidity control. This technology is appropriate for a wide range of commercial building types, including:

- Schools
- Restaurants
- Food stores
- Hotels and motels
- Hospitals
- Theaters
- Offices

Status: Commercially available. This technology is made by several manufacturers and is widely available for any of the applications listed.

Indirect/Hybrid Evaporative Cooling

Description: Conventional (direct) evaporative cooling technologies add moisture directly to a warm dry airstream to convert it to a cool moist airstream. While this decreases the indoor temperature by as much as 30°F, it also raises the indoor humidity level, which can become uncomfortably high in some climates. If the humidity of the incoming air is too high, the ability for the evaporative cooler to cool the air effectively decreases. As a result, evaporative cooling is only suited for climates where the air is hot and humidity is low.

Indirect, or hybrid, evaporative cooling uses the same principle to cool inside spaces, except that it does so without increasing humidity by using a heat exchanger of some type. The cooled moist air never comes in direct contact with the conditioned environment, so there is no increase in humidity.

Benefits: Two benefits result from application of this technology:

- Energy savings. Compared to conventional direct expansion (DX) air conditioners, indirect evaporative coolers consume less energy, because there is no compressor.
- Improved indoor air quality. The continuous supply of fresh outside air removes indoor pollutants, unlike direct expansion air conditioners, which must operate with closed windows and doors to be most effective. Compared to conventional direct evaporative cooling, there is no added humidity, which makes indirect evaporative cooling more suitable to climates that are not dry.

Applications: Space conditioning in smaller commercial buildings in arid climates. Due to their limited cooling capacities, indirect/hybrid evaporative cooling is best suited to smaller buildings.

- Schools
- Retail
- Offices

Status: While commercially available, this technology is still very new. As a result, there are just a couple of manufacturers that use slightly different approaches to achieve the same goal.

Active Magnetic Regenerative (AMR) Cooling

Description: Active magnetic regenerative (AMR) cooling technology relies on the magneto-caloric effect exhibited by certain materials when exposed to a magnetic field. The electron spins in these materials align under the influence of a magnetic field. This ordering of the electron spins results in a release of energy in the form of heat – the material heats up. When removed from the magnetic field, the spins return to their random order, absorbing heat in the process – the material cools down.

The magneto-caloric effect is being investigated as a method to cool without the use of hazardous chemical refrigerants. It is an alternative to the vapor compression cycle. In this capacity, a magneto-caloric material is cycled through magnetized and demagnetized states, and the heat in vented off to yield a net cooling effect. The efficiency and effectiveness of the technology is a function of the properties of the material and the source of the magnetic field. An ideal system would consist of a material that responds in the appropriate temperature range with the input of a simple permanent magnetic. Otherwise large electromagnets of superconducting magnets are required to yield the necessary cooling effect, and these types of magnets do not have the efficiency or simplicity advantages of permanent magnets. Researchers have recently developed a prototype magnetic refrigerator based on the material gadolinium and a permanent magnet. Further developments are in progress.

Benefits: Three benefits result from application of this technology:

- Environmentally-friendly: The AMR technology would provide an environmentally-friendly alternative to hazardous chemical refrigerants such as chlorofluorocarbons and hydrochlorofluorocarbons used in the conventional vapor compression cycle.
- Efficiency: The technology has the potential to be more energy efficient than conventional cooling systems. The efficiency is a function of the combination of magneto-caloric material and magnetic source. Researchers are currently optimizing systems.
- Few moving parts: The technology requires few moving parts, so it is potentially simple, silent, and reliable.

Applications: The technology is potentially applicable to a variety of cooling and refrigeration applications, including:

- HVAC systems
- Refrigeration
- Household appliances
- Cooling of electronic devices

Status: In development. Researchers are currently investigating magneto-caloric materials and magnetic sources. One prototype refrigeration system combines a gadolinium-based material and a permanent magnet.

Advanced Space Conditioning and Water Heating Technologies

The following technologies are described in this section:

- Heat Pump Water Heaters
- Space Conditioning and/or Water Heating using Carbon Dioxide Refrigeration Cycle

Heat Pump Water Heaters

Description: Heat pump water heaters operate on the same principle as heat pumps used for HVAC applications. With the input of electricity and a vapor compression cycle, they extract heat from a low-temperature source and transfer the heat to a high-temperature sink. In the case of the heat pump water heater, the low-temperature source is the space surrounding the water heater and the high-temperature sink is the hot water tank.

Benefits: Two benefits result from application of this technology:

- Efficiency. Heat pump water heaters are two to three times more energy efficient than electric resistance water heaters. They also help cool the indoor space during the cooling season, saving space cooling energy costs.
- Less pollution at point of use. Since the technology does not rely on combustion processes to heat the water, it eliminates gaseous emissions (e.g., carbon monoxide) at the point of use.

Applications: Small commercial and residential water heating for dedicated (stand-alone) heat pump water heaters. They can also be integrated as a water heating and space-conditioning unit. Several configurations of integrated units are used, including desuperheater water heaters and heat recovery chillers (double bundled condensers). These configurations could be deployed in a variety of applications ranging from residential to large commercial. The common features of applications well suited to these technologies are the need for relatively large quantities of hot water coupled with the need for space cooling or refrigeration. One of the applications, sit down restaurants, often requires large quantities of hot water for ware washing and food preparation while the kitchen personnel usually can benefit from additional space cooling.

Status: Commercially available from selected manufacturers. Stand-alone heat pump water heaters are most commonly used in small commercial facilities with limited penetration in residential applications. The introduction of heat pump water heaters from Japanese manufacturers into the U.S. market, using CO2 as the refrigerant, promises to improve the performance and reliability of these units. Heat recovery heat pump water heaters are available from major space conditioning manufacturers.

Space Conditioning and/or Water Heating using CO_2 Refrigeration Cycle

Description: The carbon dioxide (CO2) refrigeration cycle, or the Shecco cycle (as the Norwegian patent holders call it), uses CO2 as the working fluid in a heat pump for heating or cooling. CO2 is an effective working fluid because is has a very low boiling point and therefore can absorb heat from the surroundings and evaporate even at very low air temperatures. It is more environmentally-friendly than chemical refrigerants such as chlorofluorocarbons and hydrochlorofluorocarbons used in the conventional vapor compression cycle. When used for water heating, the CO2 cycle can replace fossil-fuel-fired water heaters. The technology can be used for simultaneous space conditioning and water heating.

Benefits: Three benefits result from application of this technology:

- Efficiency: According to developers, the Shecco technology reduces water heating electricity use by 60 to 80% over conventional electric water heaters.
- High tap water temperatures: The technology can achieve the very high temperatures needed for tap water.
- Reduced environmental impacts: The technology provides an alternative to conventional refrigerants, thereby reducing greenhouse gas emissions and helping to meet the Kyoto and Montreal Protocols.

Applications: Potential applications include water heating, space conditioning, the combination of water heating and space conditioning, cooling and refrigeration, automobile air conditioning, etc.

Status: Emerging. Gustav Lorentzen patented the Shecco technology in 1989 at SINTEF and the Norwegian Institute of Technology, NTNU. In 1990, Norsk Hydro ASA acquired all commercial rights to the technology. Cooperation with SINTEF and the University of Trondheim remains close. The Shecco technology developed at NTNU/SINTEF has been licensed to the system manufacturer through the Hydro-SINTEF joint venture. The Japanese Denso Corporation made

the first heat pump water heating system based on Shecco technology in 2000. The system (now called "ECO CUTE") is marketed by a number of companies such as Mitsubishi Electric, Daikin, Sanyo Group, Hitachi AC Systems, Matsushita Group, Toshiba Group, Corona (Denso-make), Chofu, etc.

Advanced Refrigeration Technologies

The following refrigeration technologies are described in this section:

- Energy-Efficient Case Lighting
- Electronically Commutated Motors (ECMs)
- Automatic Door Closers

Energy-Efficient Case Lighting

Description: Designed to replace traditional fluorescent lamps in both low- and medium-temperature reach-in refrigerator and freezer grocery cases, dimmable LEDs can reduce lighting energy consumption and provide up to 10 years of virtually maintenance-free service. LEDs also minimize light-source glare while providing uniform color and three times the light-level uniformity of fluorescent lighting. Because they emit less heat than fluorescent lamps, LEDs place less of a cooling burden on the cases they illuminate.

Even further energy savings are possible now that motion sensors can be added to the lighting controls. The motion sensors turn off the lights when no customers are present, but turn them back on when a customer approaches.

Benefits: Three primary benefits result from application of this technology:

- Energy savings. The efficacy of LEDs in refrigerated case applications is currently lower than that for fluorescent lamps. However, due to the lower required lighting levels, energy savings can be realized. There are also energy savings to be realized from the reduced heat emitted by the LEDs.
- Reduced environmental impact. LEDs have a lower environmental impact than fluorescent lamps due to elimination of the mercury present in fluorescent lamps.
- Improved illumination. In consumer studies, shoppers preferred the quality of the lighting provided by LEDs over fluorescent lamps, due to the improved uniformity and color.

Applications: Refrigerator and freezer cases are most often found in grocery and convenience stores.

Status: Early commercialization. It appears that only General Electric is currently marketing LEDs specifically towards the grocery case market. Further research will improve the efficiency of LEDs, which will make them increasingly more efficient than fluorescent lamps.

Electronically Commutated Motors (ECMs)

Description: It is estimated that packaged refrigeration systems consume one-half of the energy consumed by commercial refrigeration systems. Walk-in coolers and freezers are ubiquitous in all food service businesses: grocery stores, convenience stores, and sit-down and fast-food restaurants. They are also associated with food processing, packaging, and distribution centers.

Within each walk-in unit are several 10"-12" fans moving air over evaporator coils. Typically focusing on lowest production costs, manufacturers of walk-in coolers and freezers most often use low-efficiency (20%–30%) induction-type motors. Evaporator fan motors are typically less than 1/10th horsepower each. However, a typical grocery store can have hundreds of evaporator fan motors on account of all its walk-in coolers and freezers.

The electronically commutated motor (ECM) is an extremely high efficiency (65–72%) fan motor that utilizes a permanent magnet, three-phase, DC motor combined with an electronic AC inverter. In evaporator fan applications, ECMs have the potential to significantly reduce energy consumption compared to lower efficiency induction-type motors.

Benefits: Two primary benefits result from application of this technology:

- Energy savings. Third-party testing has measured energy savings of up to 68% over standard OEM motors in evaporator coil applications over a wide range of speeds.
- Longer life. Because they are brushless, ECMs suffer no mechanical wear, so they last longer than standard OEM motors.

Applications: Commercial refrigerator and freezer systems utilizing walk-in units. Typically, walk-in refrigerators and freezers are found in grocery stores; convenience stores; sit-down restaurants; fast food restaurants; and food processing, packaging, and distribution facilities.

Status: Commercially available. It appears that General Electric is the only manufacturer of ECMs at present, although there are a number of distributors.

Automatic Refrigerator & Freezer Door Closers

Description: Walk-in coolers and freezers as well as reach-in coolers are designed to be accessed regularly, but leaving the main door open wastes cooling energy and money. Auto-closers ensure that the door is fully closed after each access and remove the need to check if the door is completely shut. A walk-in door closer should firmly close a main walk-in door that is within one inch of full closure. For a reach-in door, the closer should also firmly close the door.

Benefits: Two primary benefits result from application of this technology:

- Energy savings. Automatic door closers save energy by keeping doors closed as much as possible and helping reduce the loss of cold air and infiltration of warm air into walk-in boxes.

- Worker efficiency. Kitchen workers spend less time checking to make sure walk-in and reach-in unit doors have closed behind them, which increases their efficiency and productivity.

Applications: Commercial refrigerator and freezer systems utilizing walk-in units. Typically, walk-in refrigerators and freezers are found in grocery stores; convenience stores; sit-down restaurants; fast food restaurants; and food processing, packaging, and distribution facilities.

Status: Commercially available. This technology is made by several manufacturers and is widely available for any of the applications listed.

Technologies to Enable Demand Response

To meet the growing interest in demand response, many new enabling technologies have begun to emerge in the market place. The technologies are aimed at improving metering, communications, information manipulation, and control of end-use loads. Smart meters coupled with advanced communications—particularly two-way communications—and data management technologies work together to form a more advanced metering infrastructure. Add to this smart end-use technologies and sophisticated controls, and the elements desired to optimize demand response program success start to fall into place.

There are three broad categories of technologies required to maximize the success of a demand response program:

1. advanced meters (commonly referred to as smart meters)
2. communication and information devices (which comprise an advanced metering infrastructure); and
3. load control equipment and software

The technologies work together to track energy usage (smart meters), to notify customers of a load curtailment event and to communicate near real-time customer usage information to the utility (communication and information devices), and to optimize control of end-use loads based on the given demand response scenario (control equipment and software).

Smart Meters

The first main category of technologies necessary to enable customer participation in demand response is the electric meter. In order for demand response to be effective, the metering technology must allow customers to receive price and usage signals and must allow utilities to monitor customer consumption in sufficient detail.

Conventional meters are adequate for traditional monthly billing statements; however, smart meters are necessary for more advanced functions such as time-based dynamic pricing, outage management, and other service offerings that require automatic, remote access to detailed interval data.

Conventional meters automatically measure and record usage data, but the reading or collection of the data is not automated. To read conventional meters, the meter-reader must subtract a current reading on the dial of the meter, which is traditionally an electromechanical device, from a prior reading to calculate electricity usage during the intervening period, typically a month.

Smart meters couple innovations in metering hardware and software with advancements in communications technologies. The result is that energy data can be collected accurately, frequently, and remotely. The energy data and other information such as price signals can then be communicated between the utility, the customer, and ultimately smart load control devices to effect changes in usage patterns.

Smart meters employ advances in electronics and digital technology and are capable of accurately recording, storing, and displaying energy usage information such as watts, volt-amperes, reactive power, current, voltage, and power factors in time intervals. Time-interval data are important for utilities implementing demand response programs because they are used to track changes in consumption patterns over time and in response to signals. There is also potential for end-users to access the metered data, giving them the information necessary to understand and take charge of how they use energy. Having continuous access to energy use data rather than simply receiving a bill once per month can have a significant impact on customer understanding and has been known to inspire changes in usage behavior.[75] Moreover, the utility's operating efficiency and reliability are enhanced by their ability to continuously read meters remotely, monitor outages and theft, and improve energy forecasting.

Upgrading existing meters to be capable of interval reading and recording is one alternative in improving metering technology; however, the upgraded meters fall short of the full functionality offered in new smart meters. In addition, replacing conventional meters with new meters capable of automatic meter reading also improves metering technology, but lacks the impact of installing smart meters in a fully networked advanced metering infrastructure. Some of the limitations of upgraded meters and automatic meter reading relate to the detail in which the interval data is collected, stored, and made available for other uses than just being aggregated based on a particular rate. In addition, the communication capabilities are often limited to on-site or near-site access of the data rather than being remotely accessible at all times. Moreover, they usually do not support customer access to the energy data.

The smart meters necessary for optimizing the success of a demand response program should have the following functionalities to dynamically support various service offerings and rate structures:[76,77]

- Collect and record interval energy usage data, at least hourly;

[75] Darby, Sarah. "The Effectiveness of Feedback on Energy Consumption: A Review for DEFRA of the Literature on Metering, Billing, and Direct Displays", Environmental Change Institute, University of Oxford, UK: April 2006.
[76] DRAM (Demand Response and Advanced Metering Coalition). Comments of Demand Response and Advanced Metering Coalition (DRAM) on Ontario Energy Board Staff Discussion Paper, *Implementation Plan for Smart Meters in Ontario*. RP-2004-0196, August 13, 2004.
[77] DRAM (Demand Response and Advanced Metering Coalition). Comments of Demand Response and Advanced Metering Coalition (DRAM) on *State of New York Public Service Commission, Proceeding on the Motion of the Commission to Investigate Competitive Metering for Natural Gas Service, In the Matter of Competitive Metering, In the Matter of Competitive Opportunities Regarding Electronic Service.*

- Support remote communication of interval data to the utility;
- Support time-based rates;
- Convey pricing signals to customers;
- Convey energy usage data and patterns to the customer in a user-friendly and readily accessible manner;
- Support utility applications in addition to remote meter reading such as outage management, theft detection, improved forecasting, and customer education;
- Support data processing for other applications of meter data such as energy management, customized billing, and complaint resolution; and
- Communicate with end-use load control technologies.

Figure 13-1 depicts how smart meters act as information gateways to support a variety of utility and customer functions.

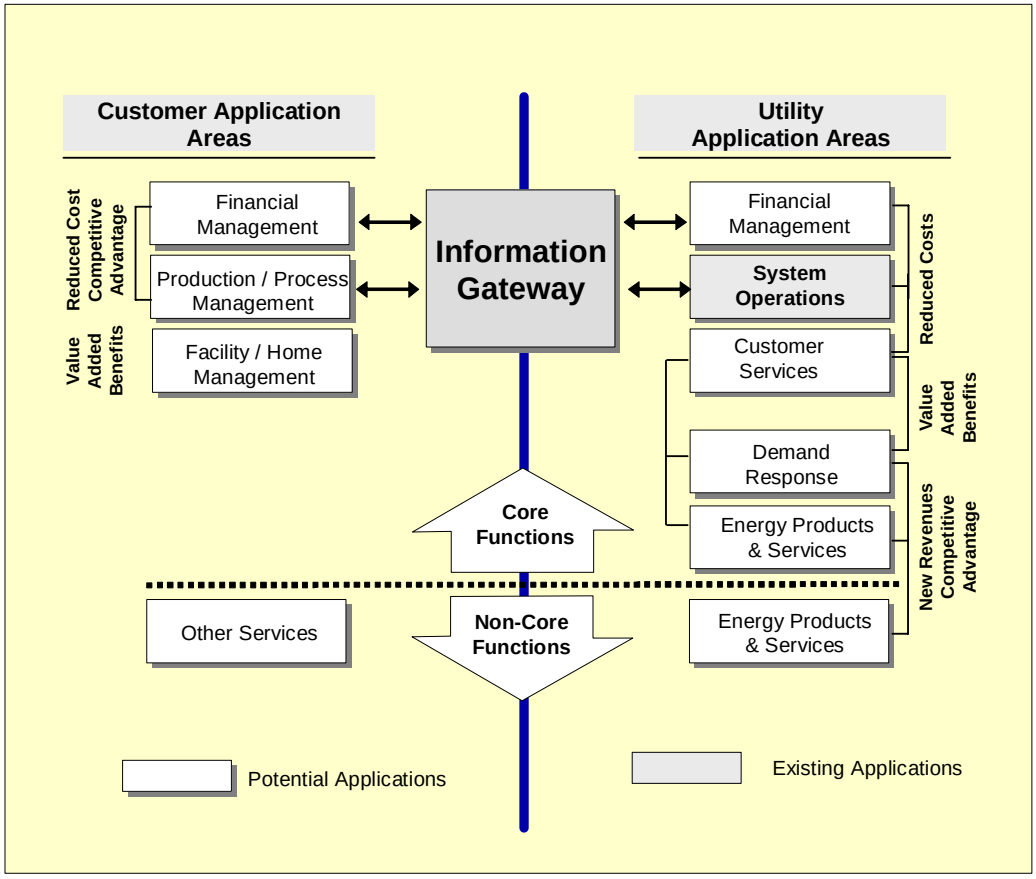


Figure 13-1
Smart Meters as an Information Gateway [78]

[78] Source: Meter Scoping Study prepared for the California Energy Commission by Levy Associates, Sacramento, CA: 2002.

Technologies for communicating information between the meter, the utility, the customer, other market entities, and end-use loads are described in more detail in the next section. In general, the information can be conveyed in a hard-wire or wireless approach via power lines, cable television lines, telephone lines, cellular phones, radio links, satellite communications, etc. The frequency in which the data are made available to the utility or the customer is a function of the system design and the given requirements. However, fixed networks are important for the success of demand response programs because of the dynamic nature of the market. Fixed networks allow utilities to have continuous access to meter interval data and event information such as outage notification, power-on verification, and energy theft. They also support continuous customer access to meter data, communication of pricing signals and other information from utilities, and direct communication to load control equipment.

Communication and Information Devices

Communication and information technologies link utilities, customers, and other market players to metered data and load control devices. The technologies consist of communication media and hardware for the transfer of data as well as software and hardware for storing the data and manipulating it into useful information. Together they constitute an advanced metering infrastructure (AMI). Communication and information technologies are essential for sharing data related to energy consumption, demand response events, and other dynamic information across communication pathways. They also enable direct communication with load control technologies. Some pathways provide one-way communications from one entity to another, while others allow two-way communications. Two-way systems are capable of both receiving and sending information and offer the most potential for successful implementation of demand response.

Communication Media and Networks

There are a variety of potential communication networks employing different types of equipment and software. Some networks are hard-wired and some are wireless. Examples of hard-wire systems include telephone lines, power lines, and cable television lines. Technologies for wireless systems vary by the distance over which the information must be transferred. Longer-range wireless systems include radio networks, cellular phones, and satellite communications, which may be employed to a greater degree in the future. Shorter-range wireless systems include technologies such as ZigBee, Z-Wave, Insteon, Bluetooth, Wi-Fi, and home radio frequency (Home RF). The communication technologies can either be standards-based or proprietary. Figure 13-2 illustrates potential communication links connecting advanced meters to utility and customer systems.

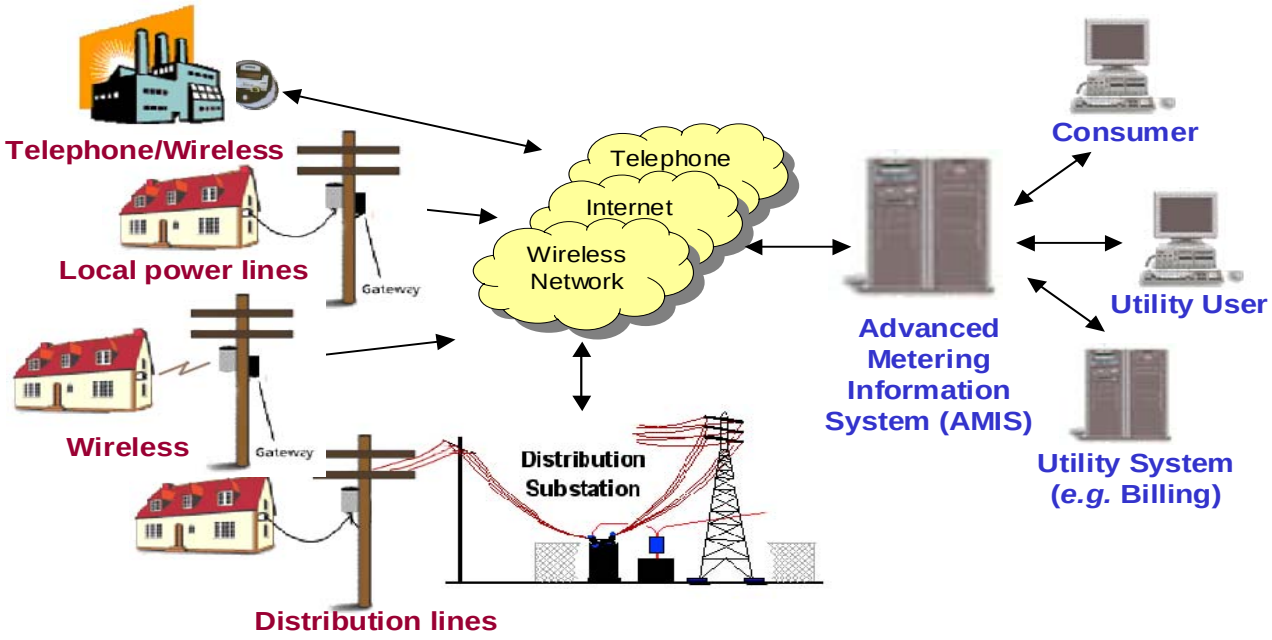


Figure 13-2
Advanced Metering Communication Network [79]

The general communications architecture needed for deploying effective demand response consists of three layers: 1) wide area network (WAN), 2) gateway, and 3) local area network (LAN). WANs are typically publicly-available networks. They can employ hard-wired media such as co-axial cable, copper wire, and fiber-optic cable as are used in cable television lines, power lines, and telephone lines. They can also employ wireless media such as cellular, radiowave, microwave, and even satellite communication technologies. WANs communicate information between utilities, customers, and other market players. WANs should be highly reliable and available with open access. The most ubiquitous WAN is the Internet. LANs are linked to WANs via an interface device, or gateway. LANs then connect to local meters, computers, and/or end-use load control equipment and other devices. They are the intermediate step that communicates between devices at the local point and the WAN. LANs employ either a hard-wired solution such as co-axial cables, twisted-pair copper wires, or fiber-optic cable (as used in Ethernet, power lines or phone lines) or they use wireless technology. In residential demand response applications, the LAN is often referred to as a Home Area Network (HAN) to differentiate it from a LAN that might encompass more than one building in close proximity. ZigBee is an example of a wireless HAN protocol that is receiving attention in the demand response arena.

[79] Source: *Comments on State of New York Public Service Commission, Proceeding on the Motion of the Commission to Investigate Competitive Metering for Natural Gas Service, in the Matter of Competitive Metering, in the Matter of Competitive Opportunities Regarding Electronic Service,* Demand Response and Advanced Metering Coalition (DRAM), Washington, D.C: 2005.

It is important for WAN and LAN technologies to be able to support a variety of functionalities, including:[80]

- Sufficient throughput and low-enough latency to support metering and/or load control applications effectively;
- Sufficient availability, or up-time, to communicate to devices effectively;
- Compatible interface standards between the LAN and WAN;
- Compatible interface standards among meters and load control devices; and
- Compatible interface standards between the WAN and the utility's information technology infrastructure.

For maximum demand response success, the standards for metering, communications, and controls technologies should all be based on an open architecture framework to allow for interoperability.

A few of the many different types of communication networks available for enabling demand response are:

- **Telephone Lines:** One way to communicate information from the meter is to use a shared or dedicated telephone line. In this case the meter is equipped with a telephone modem. Telephone communications are advantageous in that they do not require an expensive infrastructure and demand response participants can be located anywhere with nearby access to phone lines. However, the amount of time required to initiate a call and transfer data can be significant if enough meters are connected to the system, depending on how frequently the data is transferred. Shared telephone lines have the lowest cost, but access to data is more limited since the phone line is used for other purposes. Dedicated lines are a little more costly, but they allow the data to be fully accessible.
- **Fixed Radio Networks:** In fixed radio networks, transmitters and receivers are mounted on utility poles or buildings and located throughout the region to be covered. They can link directly to the meter and/or to local load controllers and allow for continuous access to data. They are a moderately priced alternative to telephones lines (roughly comparable in price to dedicated phone lines). They also allow for faster communications. Fixed radio networks work well in densely populated areas – they are less expensive to install in quantity. They may not be the best choice for reaching rural areas cost-effectively.
- **Power Line Carrier:** Communication through power lines has the obvious advantage of employing an existing infrastructure that connects directly to the meter. However, some problems still prevent this from being a completely successful solution. To date, it has been most effective for one-way communications, but has been less successful for two-way communications. Traditionally, the frequency range of signal transmission has been in the 5-100 kHz range. Transmission at a frequency of 60 Hz is a newer option for data transfer, albeit at a very slow relay rate.

[80] DRAM (Demand Response and Advanced Metering Coalition). Comments of Demand Response and Advanced Metering Coalition (DRAM) on *State of New York Public Service Commission, Proceeding on the Motion of the Commission to Investigate Competitive Metering for Natural Gas Service, In the Matter of Competitive Metering, In the Matter of Competitive Opportunities Regarding Electronic Service.*

- **Cell Phones:** Advancements in cell phone technology are making this an increasingly viable alternative for communication of data for demand response applications. Wireless cell phone networks can communicate directly with the Internet, making data transfer/access easy, fast, and continuous. The infrastructure requirements from the utility's perspective are also greatly reduced since the wireless carrier provides the server connection. This communication technology is potentially applicable to all but the most rural areas.
- **Wi-Fi:** Wi-Fi is a form of wireless network. There are several standards that fall under the general category of Wi-Fi, with varying transmission frequencies, levels of security, etc. Wi-Fi uses Direct Sequence Spread Spectrum (DSSS) for transmission and can deliver speeds of up to 11 Mbps. It is applicable for local communications and can connect to the Internet through access points or *hot spots* for external communications. It has limited range.
- **Home RF:** Home RF is another wireless network standard. It uses the Shared Wireless Access Protocol (SWAP). It transmits at a frequency of 2.4 GHz and can deliver speeds of 1.6 Mbps over distances of up to 150 ft. It is slower than Wi-Fi, but it has the advantage of being better designed to deal with interference from local appliances and to handle some forms of data transfer (e.g., voice, video, audio). It also allows for connection to the Internet through access points.
- **Bluetooth:** Bluetooth was designed to transfer data wirelessly among synchronized receivers in computing devices. It communicates with other Bluetooth devices, but was not designed for communication with network access points. It should be considered as a cable replacement technology. Therefore it is applicable for short-range local communications among compatible devices. It is an open-architecture communications standard that transmits data at a frequency of 2.4 GHz. Because it contains multiple layers of data encryption and authentication schemes, it is a very secure form of data transfer.
- **Short-Range Power Line Communications:** Technologies for short-range communication over power lines include X-10, CEBus, LonWorks, and HomePlug among many others. These technologies allow for communication and control among devices via electrical lines in the building and are commonly used for building automation. Some of these building automation technologies are also capable of wireless communications.

Advancements in wireless networks will greatly facilitate effective deployment of demand response because of their relative installation ease. Much work is currently underway by groups such as the California Energy Commission (CEC) Public Interest Energy Research (PIER) Program and the Center for the Built Environment, University of California, Berkeley to develop better wireless networks for demand response applications.

Software and Data Management Tools

There is also a variety of software analysis tools that can be used in conjunction with communication media to support demand response activities. In many cases, the software is designed into the communications system by the communication provider. [81] The capabilities of the software range widely, and include such functions as processing metering data, dynamic price data, and even external information such as weather data, as well as allowing for

[81] CEC (California Energy Commission). *Load as a Reliability Resource in Restructured Electricity Markets.* October 2003. P500-03-092F. Prepared by CERTS Program Office, Lawrence Berkeley National Laboratory;

customized management and control of energy systems based on user-prescribed energy thresholds, least cost scenarios, or other parameters. Representative companies offering this type of software product include Itron, eLutions, Silicon Energy, Honeywell, Johnson Controls, and C3 Communications. These software tools help customers better understand and manage their energy use.

Moreover, many utilities have begun to adopt and promote Energy Information System (EIS) products with demand response features. EIS is a general term for products that enable communications between utilities and customers. Products are comprised of software, data acquisition hardware, and communications systems. EIS products are capable of real-time monitoring of energy use and wholesale energy prices, and help support demand response strategies and monitoring of results. They general consist of three categories: [82] 1) notification-based systems for alerting an event; 2) analysis-based systems for energy analysis, forecasting, and billing functions; and 3) response-based systems that react to an external signal to control loads automatically (or give the operator the information necessary to control loads manually). The third type of system has the two-way communications necessary to optimize demand response and to allow for automated demand response (auto-DR).

Demand Response System (DRS) tools can be viewed as a sub-set of EIS products. Such tools are also used for notification and response. They allow for remote access and management of data, notification of pricing and events, and load control and monitoring in response to various events.

A Web-based Energy Management and Controls System (Web-EMCS) with demand response features also overlaps with DRS technologies. Web-EMCS products use the Internet to communicate with and control building systems via an EMCS. They can integrate monitoring and control of all major building systems including HVAC, lighting, etc. The control of building systems can be automated based on user-prescribed thresholds in response to demand response events.

The level of automation in demand response varies from manual to semi-automated to fully-automated.[83] Manual control allows users to physically or remotely control loads in response to communications regarding an event. Semi-automated control involves the initiation of a pre-programmed load control strategy in response to an event. In fully-automated control an external signal is communicated directly to a controller that then initiates a pre-programmed load control strategy without human involvement. Auto-DR greatly facilitates customer participation in — and the ultimate success of — demand response programs. Currently, open standards for Auto-DR systems are being developed under the classification of Demand Response Automation Server (DRAS) standards or Open Automated Demand Response (OpenADR) standards. Some of the industry standards groups involved in OpenADR include oBIX, LonMark, and BACnet.

[82] CEC (California Energy Commission). *Enhanced Automation- Technical Options Guidebook;* PUB. NO. 400-02-005f.
[83] Piette Mary Ann, Osman Sezgen, David S. Watson, Naoya Motegi. *Development and Evaluation of Fully Automated Demand Response in Large Facilities*. Lawrence Berkeley National Laboratory, March 30, 2004.

Load Control Equipment and Software

Load control equipment and software is the last major category of technologies that can enable effective demand response. New technologies to enable load control of end-use devices are entering the market at an increasing rate. Control technologies include relays or switches, thermostats, digital demand controllers, and energy management and control systems. In general, the technologies are aimed at controlling lighting and heating, ventilating, and air conditioning (HVAC) loads, but controls can extend to a multitude of other devices including appliances, pool pumps, and water heaters.

In a demand response situation, loads can effectively be controlled manually using conventional methods such as on/off switches, timers, manual dimmers (for lighting), and standard thermostats (for HVAC systems). However, the focus here is on more advanced load controls. The advanced controls may be either embedded in the device, or they may exist in a separate control system. The separate control system might control just one type of load such as pool equipment, lighting, or HVAC equipment, or it may control a variety of loads such as might be accomplished with a home automation system or building EMCS. Depending on the networking characteristics and the demand response program design, the loads can be remotely controlled by the customer or by the utility. Typically, automated control of loads is dictated by pre-defined user-programmed strategies. The strategies can be designed with a variety of constraints and generally include the ability for override.

One strategy to control lighting for demand response consists of turning off or dimming all or a portion of lighting in response to an event. This type of strategy is often referred to as a "demand-limiting" or "load-shedding" lighting strategy, wherein only non-critical lighting is turned off and generally some degree of lighting is left on for safety reasons.

Some representative manufacturers of lighting control products for demand response include Convia, Lutron Electronics Co., Universal Lighting Technologies, Lightstat, and UltraWatt Energy Systems.

Several different strategies are also used to control HVAC equipment for demand response. Many control and communications technologies being developed for HVAC equipment employ load control relays (switches) and/or smart programmable thermostats. The relays and the thermostats may be controlled remotely. The control algorithms can be set by the user or the utility. One very common technique for systems incorporating smart thermostats is to adjust the thermostat settings by a specific numbers of degrees to respond to an event. The temperature is set-up to reduce cooling loads and is set-back to reduce heating loads. This temperature set-point adjustment can be done remotely by the utility or a third-party aggregator. It can also be done by the customer.

Many load control and communication products address multiple end-use loads. For example, they may employ load control relays for controlling lighting circuits, water heaters, pool pumps, other non-critical motors, etc. while they also employ a smart thermostat for HVAC loads. The communication capabilities of the products vary, but two-way communications are becoming more prevalent for demand response products.

Representative manufacturers of load controls and communications technologies (for HVAC systems and general loads) include Carrier Corporation, Cannon Technologies, Comverge, Invensys Controls, Dencor, Site Controls, RTP Controls, Electric City Corporation, EnerNOC, Itron, and Novar Controls.

Summary and Resources

This chapter has provided summaries and descriptions of key energy-efficient and demand response technologies that are expected to play an important role in enabling savings in electricity use and peak demand.

Resources

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14
NEW DIRECTIONS

Renewed Drivers for Energy Efficiency

Energy efficiency is making a resurgence with a new generation of programs and a re-emergence of integrated resource planning. Renewed drivers for energy efficiency have already started to spur change and have spawned programs reminiscent of those in the early integrated resource planning and demand-side management days. However, program designs have also evolved from the 1970s and 1980s and will continue to evolve in new directions under the influence of these renewed drivers.

There are a variety of renewed drivers for energy efficiency. Some drivers have never really disappeared, but are now appearing at the forefront again as sound reasons for promoting energy efficiency. Such drivers include growing consumer demand in the face of limited resources, high fuel costs, and high electricity rates; dependence on energy supplies from politically unstable regions, leading to foreign tensions and compromised natural security; and concerns to protect the environment from damage due to resource extraction, conversion, and utilization. There are also drivers that can be considered new, or at least different than before. These drivers include the lifting of rate caps or freezes; new or updated energy codes and standards at the state and national levels; aging transmission and distribution infrastructure; growing consensus linking climate change to human-caused greenhouse gas emissions; and a recognition that demand response can be a viable approach for dealing with the high costs of supplying peak loads. Table 14-1 summarizes the renewed drivers for energy efficiency.

The renewed drivers are pushing energy efficiency in several new directions. For example, distributed energy resources are increasing in favor because of a number of factors. For one, they provide standby power for consumers for power reliability, power quality, and participation in demand response programs. Insofar as they provide energy storage, they can also be used by utilities for grid stabilization and operational support, power quality and reliability, and load shifting. In addition, distributed energy resources are modular and often portable, making them desirable for hard to reach customers. Furthermore, distributed energy resources based on renewables (photovoltaic systems, wind turbines, etc.) reduce dependence on non-domestic energy supplies, conserve finite resources, and help protect the environment in a sustainable manner.

Table 14-1
Renewed Drivers for Energy Efficiency

Renewed Drivers for Energy Efficiency	
Increasing Demand for Energy	Energy demand is growing as a result of population growth and economic development. The EIA projects that total primary energy consumption will increase in the US by an average of 1.1% per year between 2005 and 2030 (from 100 quadrillion Btu in 2005 to 131 quadrillion Btu in 2030) under the reference scenario.
Finite Supplies	The US depends on fossil fuels to meet energy needs, and these fuels are in finite supply. The exact quantity of fossil fuel resources is under constant debate; although, the one point that cannot be disputed is that the expense to extract fossil fuels will become increasingly higher as the supplies become more dilute and less available. Nuclear fuels, particularly for use in conventional light water reactors, are also limited in quantity. There is a potential for significantly more useful energy to be extracted from nuclear reserves if the controversy surrounding nuclear power—in particular, the use of breeder reactors and the disposal of radioactive waste—is resolved. Public resistance to nuclear power plants is very high.
Non-Domestic Energy Supplies	Resources for the two predominant energy sources, petroleum and natural gas, are concentrated in the Middle East and in Eastern European countries. Many of the countries in the Middle East are politically unstable. Several Eastern European countries are currently undergoing transition. The more the US relies on fuel imports from less stable governments, the more we run the risk of compromising national security. This is evidenced by continued tensions with the Middle East.
High Oil Prices	Fuel costs are rising nationwide because of developments in world energy markets. Oil prices recently reached the highest price on record, even in real terms. (At the time of writing, oil prices were above $95/barrel.)
Lifting of Rate Freezes	States that had imposed rate freezes to facilitate competition are faced with significant price hikes as those freezes expire. Higher prices may cause consumers to look for ways to reduce their consumption.
National Standards, Codes, & Legislation	Energy standards, building codes, and legislation have been developed at the national level and are periodically updated to promote energy efficiency (e.g., ASHRAE 90.1, the Model Energy Code (MEC) which is now also referred to as the International Energy Conservation Code (IECC), and the Energy Policy Act). Various provisions to provide incentives to consumers for exceeding minimum efficiency requirements have also been developed.
State Regulations and Goals	A few states have adopted their own energy codes and standards that are mode stringent than national requirements. A prime example is California's Title 24. In some states, energy efficiency "portfolio standards" akin to renewable energy portfolio standards are also being adopted.
Aging Infrastructure	Need to replace significant portions of the nation’s transmission and distribution infrastructure.
Environment Concerns: Carbon Reduction, Health & Safety	Reducing carbon emissions as a means to arrest the pace of climate change has emerged as a major driver for energy efficiency. Public awareness of, and concern about, climate change is cresting as the scientific consensus mounts that climate change is linked to greenhouse gas emissions caused by human activity. Insofar as energy efficiency reduces load it reduces generation, and in-turn, avoids incremental emissions of carbon from fossil-fuel fired plants. In addition, gaseous and particulate emissions from power plants (as well as industrial plants) can present other environmental and health concerns to humans and other living species.
High Cost of Peak Loads	Greater cognizance that it is very expensive to supply peak loads. More energy companies understand there is a need to provide consumers with price signals and extra incentives to encourage them to curtail peak usage.

Renewed drivers are also leading to a growing interest in hybrid electric vehicles. These vehicles have the potential to reduce mobile emissions considerably and could also be tied into the power grid.

Moreover, the need for an upgrade of the U.S. power infrastructure is driving a movement to replace the current infrastructure with a *Smart Grid*. A Smart Grid would feature advanced control and communications capabilities. It would greatly enhance electricity transmission and distribution, and would allow for improved customer service. It also has the potential to yield significant energy savings and reductions in carbon emissions.

Carbon taxes and trading systems have been invoked in Europe and Australia as means to reduce carbon emissions in response to climate change. Currently, the U.S. mainly endorses voluntary measures for carbon reductions; however, as the climate change mitigation movement continues to pick up speed, the U.S. may respond in a new direction toward mandated carbon taxes and trading.

Consideration of all of the renewed drivers has prompted EPRI to develop another direction for energy efficiency that is completely new. It is referred to as *Dynamic Energy Management*. Dynamic Energy Management merges energy efficiency, demand response, and distributed energy resources in an integrated framework that simultaneously addresses permanent energy savings, permanent demand reductions, temporary peak load reductions, and even power quality and reliability. The framework relies on smart and efficient end-use devices and distributed energy resources as well as a Smart Grid infrastructure to enable dynamic control of the entire system.

The following sections describe these new directions in energy efficiency in greater detail.

Distributed Energy Resources

Distributed energy resources include technologies for distributed generation and electric energy storage. Important subsets of distributed energy resources are technologies for combined heat and power, renewable generation, and power quality and reliability. Distributed energy resources are gaining more interest from electric utilities because they deliver electricity closer to the point of use, better match demand with supply, and mitigate the need for new generation and transmission facilities. They are also valuable in hard-to-reach locations.

A new wave of applications for distributed energy resources is to tie them into the grid. Some of the challenges of grid integration relate to the inherently less controllable nature of certain important distributed resources, namely renewables such as wind power and solar photovoltaics, which intermittently feed energy to the grid. Electric energy storage is one solution to the intermittent generation problem. Large-scale energy storage and discharge allows decoupling of distributed generation from demand, increasing resource dispatchability and allowing intermittent renewable resources to operate during periods of maximum efficiency. Grid integration of distributed energy resources would be facilitated by deployment of a Smart Grid infrastructure. In addition, applying the principles of Dynamic Energy Management is a means to optimize dispatch of distributed energy resources in concert with demand-side energy efficiency technologies and alternatives.

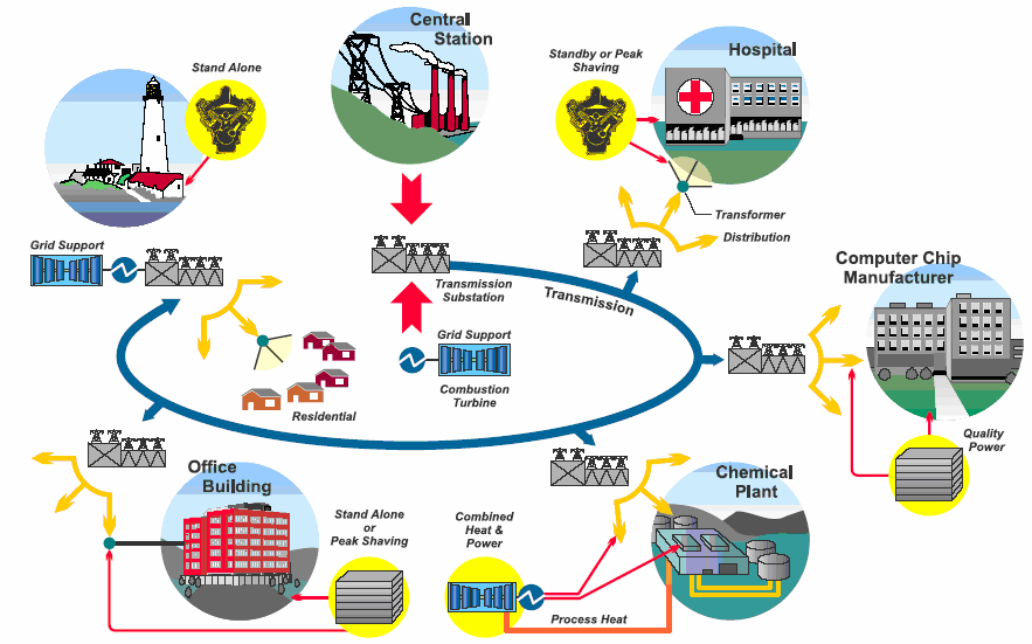
Various trends in the industry are affecting directions in distributed energy resources. These trends include:

- Increased time-of-use metering: Many utilities already charge different rates for energy depending on when it is used, although such schemes are generally restricted to commercial and industrial customers. If such schemes also catch on for residential customers, distributed energy resources become more viable for providing power at peak times.
- Increased use of demand charges: Most utilities implement a charge for peak demand, based on the peak power drawn by a customer over a 15 minute period in a given month. While details differ—some measure over 30 minute periods, some charge only for commercial and industrial customers—such charges can make it expensive for customers who have occasional high power demands.
- Opportunities for participation in energy efficiency programs: Utilities and other energy market players are implementing energy efficiency programs to improve capacity utilization on the grid. Customers can effectively sell energy to the grid by agreeing to reduce their power consumption during certain times of the day. A customer can accomplish this without actually reducing power consumption if they use local generation or stored energy during this time period.
- Increased implementation of net metering: Some state and local governments are forcing utilities to implement net metering, which allows customers to sell excess power back to the grid at current rates. Such schemes can make distributed energy resources very attractive investments for homeowners.
- Increased volatility in fuel prices: The increased prices of natural gas and other fuels make improved efficiency and energy utilization very important. Combined heat and power products can actualize this by ensuring that both the electrical and thermal power output from generation are used.
- Increased demand for high-quality electricity: Our increasingly digital society requires high-quality power with very high reliability. Energy storage and combined heat and power products can improve power quality in locations where it is needed, by controlling and maintaining power quality locally.

Distributed Generation

Distributed generation (DG) technologies are becoming important tools to augment the large central power generators of the present-day electrical grid. This arrangement puts generation closer to the end-user, improving power reliability, quality, and security. DG devices include small-scale generation devices that feed power onto distribution grids, as well on-site generation that provides power to a single building or facility, possibly including cooling or heating functions. On-site DG devices can be used to improve power reliability, quality, and security for individual buildings. An electrical supply system that is organized in an Internet-like approach containing a large number of interconnected power generation devices will be an important foundation to a transformed future energy supply system.

Central station power plants are few in number and deliver power into the transmission grid at voltages greater than 110 kV. DG systems, by contrast, can be considerably larger in number and feed power into the distribution grid at voltages in the 3 to 34 kV range. A further distinction can be made between utility DG and on-site or building DG. Utility DG is used to generate power at the distribution level, serving many customers, and is used to relieve bottlenecks in the transmission infrastructure and improve power quality and security. Building DG is used at the customer site (i.e., residential or commercial building or industrial facility). Figure 14-1 shows some typical DG applications.



Source: Distributed Generation, Federal Energy Technology Center, www.fetc.doe.gov

Figure 14-1
Typical Distributed Generation Applications

Many DG technologies are at an early stage of market adoption. Cost and power conversion efficiencies will improve over the coming decades, making them more attractive energy sources. Table 14-2 shows the cost and efficiency improvements of a selected set of generation technologies between 2004 and 2025. All costs are expressed in 2003 constant dollars. It is important to understand that while these figures show efficiency and cost improvements, they are not absolute indicators of the resulting cost of electricity.

Table 14-2
Cost and Efficiency Projections for Select Distributed Generation Options

	2004		2025	
Technology	**Cost/kW**	**Efficiency**	**Cost/kW**	**Efficiency**
Residential Photovoltaic	$8,600	14%	$3,180	22%
Commercial Photovoltaic	$6,250	14%	$2,650	22%
Commercial Fuel Cell	$5,200	36%	$1,450	52%
Natural Gas Turbine	$1,860	22%	$1,539	28%
Natural Gas Engine	$1,130	32%	$915	34%
Natural Gas Microturbine	$1,773	28%	$818	39%

Source: Energy Information Administration, Annual Energy Outlook 2005

Diesel and gas reciprocating engines and gas turbines are well-established DG technologies. Industrial-sized diesel engines can achieve fuel efficiencies in excess of 40 percent and have a relatively low cost per kilowatt. Unit sizes range from a few kW to well over several MW, but most of the units installed have capacities ranging from 10 to 200 kW. The majority of installed units serve as backup generators for sensitive loads (such as special manufacturing facilities, large information processing centers, hospitals, airports, military installations, large office towers, hotels, etc.) for which long-duration energy supply failures would have catastrophic consequences. However, the demand for units for continuous or peaking use has also been increasing.

The fuel cell is an emerging DG technology. It is scalable from a few Watts—to power electronic devices such as laptop computers—to more than 100 kW to power and heat buildings or charge plug-in hybrid electric vehicles (PHEVs).[84] Research is also being directed at developing large-scale fuel cell systems for utility use as central power plants. Fuel cells are considerably more efficient than combustion-based generators, achieving efficiencies of up to 60 percent for electricity generation and efficiencies in excess of 80 percent for combined heat and power applications. Fuel cells operate at low temperatures with no noise, and since they are fueled by hydrogen they emit no on-site greenhouse gas emissions.

While fuel cells are commercially available, they are more costly than combustion-based generation technologies. Supplying hydrogen to fuel cells remains a principal challenge due to the inherent difficulties in storing and transporting hydrogen gas. Hydrogen can be created by either reforming fossil fuels or by electrolysis, an electrochemical process that splits water into hydrogen and oxygen. Fuel reforming systems are based on steam reforming technology and require large industrial plants. Present efforts are focused towards the creation of small reformers that can be used in fuel cells.

[84] A fuel cell consists of two electrodes—a negative electrode (or anode) and a positive electrode (or cathode)—sandwiched around an electrolyte. Hydrogen is fed to the anode, and oxygen is fed to the cathode. Activated by a catalyst, hydrogen atoms separate into protons and electrons, which take different paths to the cathode. The electrons go through an external circuit, creating a flow of electricity. The protons migrate through the electrolyte to the cathode, where they reunite with oxygen and the electrons to produce water and heat.

The generation of electricity through DG—whether the combustion of fossil-fuels (such as natural gas, diesel, fuel oil, or propane) or the chemical reaction of a hydrogen fuel cell—produces vast amounts of heat. In combustion processes, over 50 percent of fuel energy is converted to heat, which is not typically captured and is therefore largely wasted. Combined heat and power (CHP) systems capture this waste heat to provide other end-use services such as steam, hot water, or space heating, thereby improving overall resource efficiency. As an example, a microturbine has an efficiency of roughly 30 percent. If all the waste heat can be used for other applications at the point of generation, the overall efficiency of the system can increase to as much as 85 percent. CHP has traditionally been dominated by large industrial systems (greater than 25 MW) that provide onsite electric power while providing heat for onsite use and/or to heat nearby communities. Residential CHP applications are just starting to be adopted in the market place. Residential systems are small (~1-5 kW) and usually operate with propane or natural gas to deliver electric power and heat for water or space heating.

While there are many different renewable energy sources applicable for DG, most of them are not widely available. Renewable resources include solar energy, wind, geothermal, hydro, wave, tidal, salinity gradient, etc. Of the commercially available renewable energy sources, solar is the most widely available for DG application, principally in the form of rooftop photovoltaic (PV) systems. PV cells are semiconductor materials that convert photonic energy (light) into electricity. They are usually connected together to form modules or panels that may be up to several feet long and a few feet wide. Modules, in turn, can be combined and connected to form PV arrays of different sizes and power outputs, typically ranging from 2-3 kW for residential applications to several hundreds of kWs for larger applications. While PV systems are reliable, scalable, and produce zero operating emissions, they are not yet cost-competitive with fossil-based generation options. Despite this cost obstacle, net-metering arrangements between utilities and customers with PV systems are becoming more common. Moreover, techno-economic trends suggest that PV systems are likely to experience cost breakthroughs.

Industrial- and commercial-scale DG systems have achieved greater market penetration than smaller-scale residential systems, which are technologically less mature. In addition, regulatory hurdles and a lack of market incentives contribute to the limited adoption of small-scale DG systems. Noise and emissions are also significant barriers to the penetration of small-scale residential DG applications, with regulations for both increasingly stringent. While presently expensive, zero emission and zero noise resources like renewables or fuel cells have the attributes for eventual acceptance as residential DG technologies as their costs decline.

Electric Energy Storage

Large-scale electric energy storage has yet to attain techno-economic feasibility, which is why electricity—as it has been since the time of Edison—must be generated as it is demanded. At present, electric energy storage is most commonly associated with backup power systems, such as small-scale uninterruptible power supply (UPS) systems and substation backup batteries for power quality and reliability. The restructuring of the utility industry, along with increased requirements for renewable power, power reliability, and power quality, has made the idea of grid-connected energy storage more compelling. Large scale energy storage is an enabling technology for integration of renewable energy resources into the grid. It could also help the grid return to normal operation after a disturbance or support everyday grid operations. These

factors have spurred research and development into a number of new energy storage technologies. [85]

Power Quality and Reliability

Energy storage is often used to improve power quality and reliability at the distribution level. The vast majority of grid-related power quality events are voltage sags and interruptions with durations of less than 2 seconds, phenomena that lend themselves to energy storage-based solutions.[86] In fact, energy storage is already widely used in the most common solution to these problems, the uninterruptible power supply (UPS).

There are several types of UPS products but all of them have one basic purpose: to ensure that devices plugged into the outlet receive a steady stream of high-quality power. A UPS normally provides its output with power taken directly from the grid; the UPS may provide some type of conditioning to this power. In the event of an interruption in grid service, the UPS provides power from a battery or other energy storage system.

UPS systems are found in many shapes and sizes, from small computer UPS systems rated for a few hundred watts, to larger UPS systems for data centers, which may be rated in megawatts. There are also DC backup systems, such as the batteries used for telecommunications and substation backup power. Many UPS systems are further augmented with some type of generation such as a diesel generator for long-term outages.

Large UPS systems can be divided into two types: short-term UPS and long-term UPS. Short-term UPS provides backup power for a few seconds, long enough to ride through the vast majority of disturbances, and long enough to turn on a generator for longer outages. Long-term UPS provides power for as long as several hours, in the event that generators cannot be used (for environmental reasons, for example).

Recently, the use of large-scale energy storage systems as UPS for the entire distribution network has been proposed. The UPS Substation™ is a concept developed by EPRI to mitigate power quality problems at the substation level, through the installation of a large energy storage system at a substation. The load serviced by the substation would be supported by the energy storage system, even in the event of a large-scale outage. The UPS could also be used for other purposes, such as peak shaving or voltage support.[87]

Energy storage in power quality and reliability applications holds the most benefit for end-users who have critical loads which must be supported at all times. Utilities might benefit by providing premium power services to clients who are willing to pay for them.

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[85] EPRI is pursuing a large-scale demonstration project of compressed air energy storage, driven in large part by the industry need to develop viable storage to facilitate the integration of renewable energy sources onto the grid, which are inherently intermittent.

[86] *An Assessment of Distribution System Power Quality, Volume 2: Statistical Summary Report.* EPRI, Palo Alto, CA, January 1998. TR-106294.

[87] *UPS-Substation™: Evaluation, Conceptual Design, and Generic Specification.* EPRI, Palo Alto, CA: 1998. TR-111091.

Grid Stabilization / Normal Grid Operations

Electricity storage can be used to help the transmission or distribution grid return to its normal operation after a disturbance. Energy storage can be considered in the attempt to remedy three forms of instability: rotor angle instability, voltage instability, and frequency excursions. Grid stabilization applications provide the most benefit to utilities, whose networks may suffer as a result of instabilities, and who may be penalized for outages caused by instabilities. End-users benefit from improved reliability of the power system.

In addition to stabilizing the grid after disturbances, energy storage can also be used to support normal operations of the grid. Four types of support operations can be performed through the use of energy storage: frequency regulation services, contingency reserves, voltage support, and black start**.**

Load Shifting

One of the most prominent new directions for energy storage is load shifting—the storage of energy during periods of low demand for release during periods of high demand. Load shifting comes in several different forms; the two most common are *peak shaving* and *load leveling*.

Peak shaving describes the use of energy storage to reduce peak demand in an area. It is usually proposed when the peak power for a system is much higher than average load, and when the peak power occurs relatively rarely. For example, the peak power draw may occur on the afternoons of the hottest days of the year, when air conditioning units turn on. Such an event occurs only for a few hours a day, and then only on a few peak power days in the year. The number of peak load hours in an entire year makes up a very small percentage of the total hours in the year. Even though the peak load is quite uncommon, all sections of the power system—generation, transmission, and distribution—must service that peak load. This situation can result in significant additional investment in capacity and a low utilization factor.

Peak shaving allows a utility to defer the investment required to upgrade the capacity of the network. In a peak shaving arrangement, energy storage is installed on the load side of the equipment requiring an upgrade. Most of the time, the load is within the capacity of the existing equipment, and the entire load is served by the grid. When the load exceeds the equipment's capacity, the energy storage begins to discharge, reducing the load supplied by the grid. An example is illustrated in Figure 14-2. Note that the energy storage draws power from the grid during the off-peak times to recharge.

The economic viability of energy storage for peak shaving depends on a number of factors, particularly the rate of load growth. If load growth is slow, the additional capacity provided by a distribution upgrade will be underutilized for a long time, providing poor payback for a large investment. A peak-shaving energy storage option makes sense under these conditions. If load growth is fast, however, the additional capacity will be taken up quickly. In this case, it is better to make a single initial investment rather than a number of smaller but ultimately more expensive investments in peak-shaving energy storage.

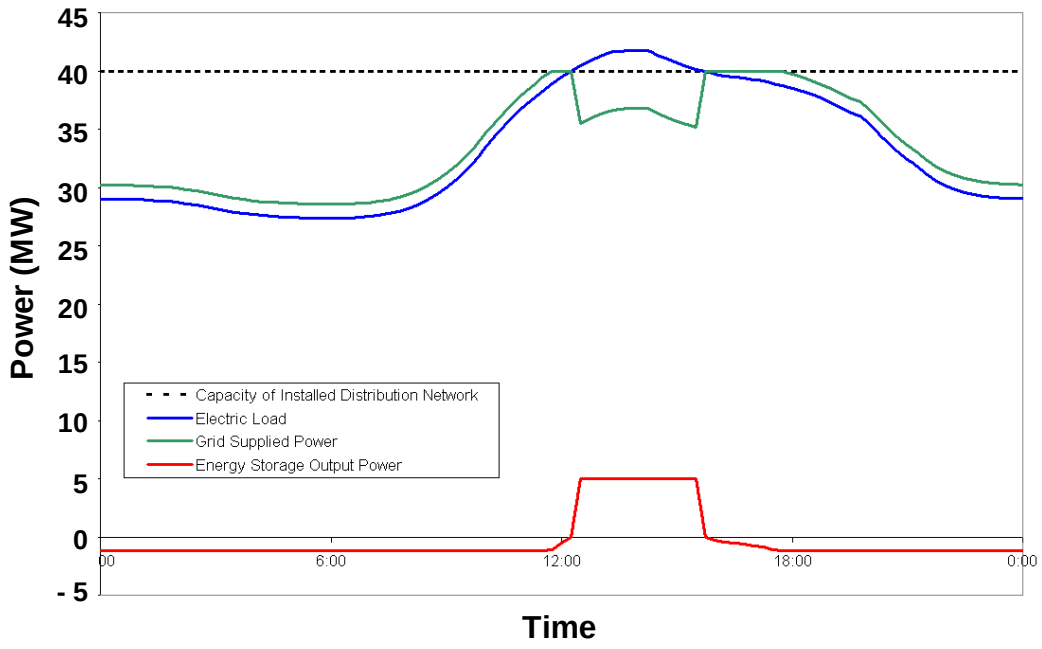


Figure 14-2
Peak Shaving with an Energy Storage System

Load leveling is another load shifting concept in which energy is stored at night for use during the day. This concept is useful in areas where time-of-use metering is in place, and is particularly popular in places such as Japan, where the daytime electricity rate can be several times the nighttime rate. Load leveling also requires larger energy storage systems, since the energy storage will bear the majority of the load during the day. For this reason, load leveling is typically done with energy storage on the customer side of the meter, rather than by the utility. Load leveling is illustrated in Figure 14-3.

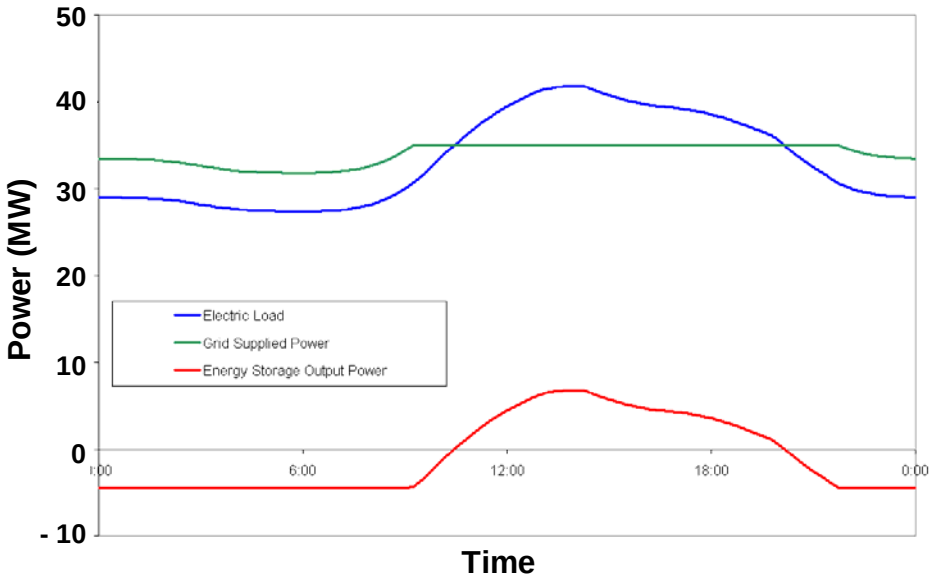


Figure 14-3
Load Leveling Using Energy Storage

Renewable Power

Because of their inherent intermittency due to weather and other uncontrollable factors (e.g. cloud cover, wind speeds, etc.) many renewable resources are difficult to match with load, making their integration into the grid problematic. Energy storage eases this problem by absorbing energy when the generated power exceeds the need, and covering the shortfall when the generated power is less than needed. Energy storage can be used to reduce the variability in renewable power sources, making them more fully dispatchable and potentially allowing them to displace conventional generation sources. Policy drivers for renewable energy, including state renewable portfolio standards (RPS), have brought urgency to the technical issues of large-scale integration of renewable energy resources to the grid. In order to meet state RPS requirements, large-scale energy storage technology must develop to facilitate the integration of renewables.

Plug-In Hybrid Electric Vehicles

In general, a hybrid electric vehicle (HEV) uses a primary fuel such as gasoline or hydrogen to generate electricity. The electricity is then used to power an electric propulsion system. Batteries are used to provide short-term energy storage, which allows the electrical generation system to run at optimal performance and also to store energy from breaking. HEV technology offers significant benefits to conventional vehicle technology such as lower emissions, better fuel economy, and potentially fewer operations and maintenance issues.

While there are many variations in how an HEV can be configured, the main advantages of HEV technology are:

- Regenerative breaking: Instead of using traditional breaking pads, which turn breaking energy into heat, HEVs use their electric motors to slow the vehicle down, charging the onboard batteries. This feature is the primary reasons for excellent gas mileage in inner-city driving.
- Cleaner combustion: Because the battery takes care of short-term energy storage, the engine can be run at optimal rpm and load, leading to cleaner combustion of the fuel.
- Higher reliability: The elimination of maintenance-intensive systems such as clutches, gears, and breaks leads to a potentially more reliable system that requires less maintenance.
- Improved fuel economy: HEVs provide superior fuel economy as compared to traditional drive trains. This is especially true in inner-city driving, where regenerative breaking allows capture of breaking energy that otherwise would be lost.
- Battery-only mode: HEVs can drive in battery-only mode, which allows them to start instantaneously and makes very quiet operation possible. Sixty percent of all annual miles driven in the U.S. are for trips less than 40 miles long. If the battery is large enough, this mode can be used to commute to work and for other short trips.
- Fuel Flexibility: A variety of energy sources can be used to generate the electricity used in HEVs.

Commercially-available HEVs are becoming very popular, and many technological advances are underway leading to improvements in onboard electrical energy storage, electric motors, drive concepts, sensors, and control systems.

One such advancement is the plug-in hybrid electric vehicle (PHEV). EPRI has been a major leader in PHEV research, analysis, and development. Figure 14-4 shows two PHEVs being tested at Argonne National Laboratory (ANL), one of EPRI's research partners in PHEV development. PHEVs are expected to enter the marketplace in 2010 and should continue to gain market penetration because of their superior fuel efficiency and environmental benefits. PHEVs represent a new generation of HEVs that combine the versatility and fuel efficiency of commercially-available HEVs with the high efficiency of battery electric vehicles. They differ from today's HEVs in that they have higher capacity batteries allowing them to drive in electric-only mode for up to 20-40 miles; beyond that range, they operate like conventional HEVs. The greater distances achievable in electric-only mode equate to lower emissions and better fuel efficiency. They are expected to reduce emissions and fuel consumption by 30 percent over today's commercially-available HEVs (see Figure 14-5). At the same time, PHEVs can be recharged by plugging them into an electrical outlet for a few hours, offering potentially powerful synergies to complement the electric power grid.



Source: Argonne National Laboratory, Transportation Technology R&D Center

Figure 14-4
Testing of Plug-in Hybrid Electric Vehicles

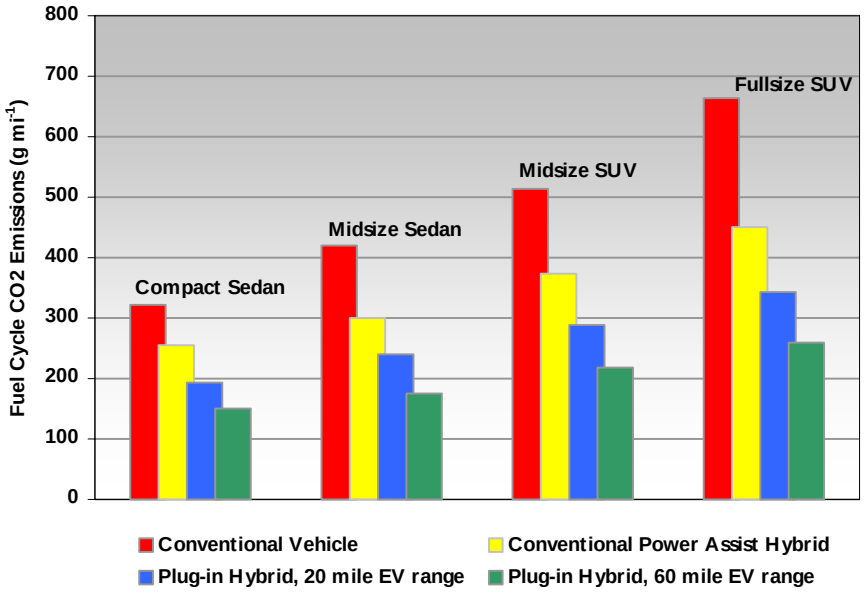


Figure 14-5
Comparison of Vehicle CO_2 Emissions: Conventional, Hybrid, PHEV

Widespread market adoption of PHEVs potentially offers significant societal benefits in the form of reduced net emissions of greenhouse gases and criteria pollutants important for air quality. Studies of U.S. commuters indicate that about 60 percent of all annual miles traveled are for trip distances of less than 40 miles—a driving range for which PHEVs can operate in electric-only mode. The ability to travel more miles in electric-only mode will reduce externalities such as mobile emissions and increase the vehicle's overall "well to wheel" efficiency. The impact of PHEVs on overall emissions will vary depending on the generation mix of the utility that provides the electricity to the vehicle, the efficiency of the vehicle under battery-mode, and the efficiency of the vehicle when powered under fuel-mode.

A study conducted in 2007 by EPRI with the involvement of the Natural Resources Defense Council (NRDC) concluded that the deployment of PHEVs in the U.S. will lead to reductions of 3.4 to 10.3 billion metric tons of greenhouse gases by 2050, as a function of PHEV fleet penetration and the carbon-intensity of the electricity generation mix.[88] That is, that additional carbon emitted by power plants to charge PHEVs are more than offset by the avoided carbon emissions from reducing the combustion of gasoline from vehicle internal combustion engines.

From a utility perspective, the ability to charge PHEVs during off-peak periods (i.e. overnight) provides operational benefits through improved system load factor and utilization of base load resources. Moreover, electricity sales that would accrue from PHEV charging would represent additional revenues for load serving entities in states that have not decoupled kWh sales from utility revenues.

However, integration of PHEVs into the electrical grid also presents challenges for electric utilities. Consumer charging behavior is a matter of speculation since PHEVs are only expected to enter the North American market in the 2009-2010 time frame. Widespread consumer charging of PHEVs during peak periods in the day, for example, could increase peak load and increase utilities' operational costs. The development of a Smart Grid, discussed in the next section, is therefore vitally important to utilities, since it entails the intelligence to send signals to consumers on when to charge their vehicles or provide differentiated rates to encourage off-peak charging.

With parallel advances in smart vehicles and a Smart Grid, PHEVs may emerge as a new form of distributed energy resource, able to provide energy storage and emergency supply and support grid stability. A PHEV could, for example, be used to provide emergency power to a home during an outage, acting as a backup generator. In addition, a PHEV's onboard batteries could be discharged during peak periods to provide electricity at the customer premises, thereby reducing the need for grid electricity, which would result in peak load reduction.

Over a longer term horizon, as "vehicle-to-grid" technology develops, PHEVs may become enabled to discharge electricity into the grid when not in use, thereby representing additional grid resources. A Smart Grid infrastructure would need to impart the appropriate signals—such as dynamic bids—to consumers to encourage PHEV discharge during times most cost-effective and beneficial to the utility (i.e. during critical peak periods in congested locations) and discourage discharge during other periods.

[88] EPRI. "Environmental Assessment of Plug-In Hybrid Electric Vehicles—Volume 1: Nationwide Greenhouse Gas Emissions." 1015325. Palo Alto, CA. 2007.

Smart Grid

The increasingly interconnected and information-based society and its technologies require high power reliability, quality, and security. These requirements are oftentimes not being met by the existing power supply system. Today's electrical power network faces challenges and will require significant build-out to meet the additional power needs of future society and to conform to new developments in smart energy efficiency technologies (see Chapter 13), distributed energy resources, and PHEVs. Developments in these areas will focus on a number of common attributes. First, these devices will have high levels of distributed intelligence built into their basic operating structure, allowing them to become smart resources that are interactive with their digital environment. Second, they will incorporate standardized communication protocols, affording high levels of interoperability with other devices through an advanced infrastructure. Third, they will be designed for integration with a smart electricity infrastructure at multiple levels—the distribution level, the energy management systems level, and the grid operations and planning level. Consequently, while established research and commercial activities continue to develop core technologies for energy efficiency, distributed energy resources, and PHEVs, parallel research and development efforts are required to transform the distribution system into a smart enabling infrastructure, or *Smart Grid*.

The term Smart Grid may be best understood as the overlaying of a unified communications and control system over the entire power delivery infrastructure to provide the right information to the right entity (e.g. end-use devices, transmission & distribution system controls, customers, etc.) at the right time to take the right action. It is a system that optimizes power supply and delivery, minimizes losses, is self-healing, and enables next-generation energy efficiency applications. It is an essential element in EPRI's vision for the Dynamic Energy Management framework discussed later in this chapter.

Regional transmission operator PJM views a Smart Grid as encompassing three elements:[89]

- Transitioning the grid from a radial system to a true network to ensure connectivity from generation sources to end-use customers
- Converting from an electro-mechanical to a fully digital system to support information and automation-enabled assets
- Enabling two-way communication within the grid community so that customers can, if they choose, move from passive to active participation in the marketplace

A Smart Grid would entail an open standard for communications with devices (both transmission and distribution and end-use devices), advanced metering infrastructure (AMI), 2-way communications between a utility and its customers, and smart interconnections to distributed energy resources. All of the elements of a Smart Grid would be linked and in constant communication to optimize performance while maximizing energy efficiency and minimizing negative environmental impacts.

[89] *Facilitating the Transition to a Smart Electric Grid*, Testimony of Audrey Zibelman, PJM Chief Operating Officer and Executive Vice President, before U.S. House of Representatives Committee on Energy and Commerce, May 3, 2007.

A Smart Grid's enhancements in communications and control functionality could potentially unleash mechanisms for achieving greater levels of energy savings. Five of the main possible mechanisms are summarized below.

- **Continuous commissioning of large commercial buildings:** A Smart Grid would facilitate *continuous commissioning*, whereby equipment settings and performance could be constantly monitored and updated to optimize performance and efficiency. With the two-way communications of a Smart Grid infrastructure in place, a utility could monitor the performance of major customer equipment through advanced interval metering and on-premise energy management control systems. The utility would be able to send alerts to a facility energy manager to indicate if major equipment is not performing up to nameplate efficiency specifications. With this information in hand, the facility manager could then choose to either adjust the operational settings of existing equipment or replace sub-optimal equipment with more energy-efficient equipment to improve overall operational efficiency. Depending on the service agreement, the utility could also offer to send a representative to re-commission the equipment for a customer. The result would be a greater degree of proactive maintenance.
- **Enhanced voltage regulation and reduced transmission and distribution line losses:** A Smart Grid would enable adaptive voltage control on certain types of circuits to lower distribution voltage, and thereby reduce load levels, while maintaining acceptable voltage levels at the feeder end. There are a number of measures that utilities can undertake to reduce transmission and distribution losses, including upgrading distribution transformers, reconductoring, and building new substations. However, these measures require large capital expenditures on the power infrastructure and are usually undertaken to meet transmission and distribution capacity or replacement requirements rather than for the purpose of reducing losses. A Smart Grid has the potential to reduce energy losses that occur in the transmission and distribution of electricity from generation sources to end-users, using this existing power infrastructure. The promulgation of open communications standards through a Smart Grid would enable utilities to monitor and modulate the operating parameters of otherwise disparate components in the transmission and distribution infrastructure.
- **Energy savings through peak load management:** The curtailment of load during a demand response event often yields energy savings. The amount of energy savings is a function of the frequency and duration of the demand response event. A Smart Grid, particularly with an advanced metering infrastructure in combination with smart devices, would enable more frequent and longer duration demand response events and direct control of devices, which in turn could yield incremental energy savings. However, it is important to note that demand response activities that only serve to shift load from on-peak to off-peak periods may not necessarily save energy. Moreover, some demand responsive load shifting strategies may actually increase net energy consumption through a "rebound" effect in which more energy is used during the off-peak to compensate for energy saved during the on-peak.[90]

[90] *A Survey Of Time-of-Use (TOU) Pricing and Demand-Response (DR) Programs,* prepared for the U.S. Environmental Protection Agency, prepared by Energy & Environmental Economics, San Francisco, CA: July 2006.

- **Direct feedback to customers:** A Smart Grid could enable direct feedback to consumers on their power consumption conveyed on sophisticated meters and/or on in-building display devices. The information presented to consumers could consist of various dynamic parameters such as current and historical energy use, demand, pricing conditions and alerts, and even equivalent CO_2 emissions. The forms of display devices under development vary, consisting of visual indicators employing data tables, charts, color-codes (e.g., the Ambient Energy "Energy Orb"), and flashing lights as well as audio indicators in which alarms are triggered by preset values to inform the consumer of pending price events or energy use thresholds. These display devices could be used in conjunction with demand response programs or could be used simply for increasing consumer awareness.
- **Accelerated deployment of energy efficiency programs through superior measurement and verification capabilities:** The advanced metering and communications infrastructure of a Smart Grid would support the measurement, storage, and retrieval of data to verify energy savings and demand reductions readily. This relative ease of measurement and verification would give utility planners more confidence to incorporate energy efficiency and demand response into integrated resource plans and facilitate greater utility use and reliance upon demand-side resources. Through its enhanced measurement and verification capabilities, a Smart Grid would support emerging business models that increase the cost-effectiveness of energy efficiency programs for utilities. This, in-turn, has the potential to accelerate deployment of energy efficiency programs beyond current levels.

In a recent study, EPRI assessed the value of a Smart Grid in terms of its potential to enable incremental energy savings and CO_2 emissions reductions. The energy savings potential of the five Smart Grid-enabled mechanisms listed above were considered. In addition, the CO_2 emissions impact of a Smart Grid through facilitating greater integration of renewable resources and market penetration of PHEVS were also considered. Table 14-3 summarizes first-order approximations of the energy savings potentials and corresponding values of avoided CO_2 emissions in the U.S. for each of these five main mechanisms in the target year of 2030. Low-end and high-end values are included to show the ranges of savings. All of the mechanisms combined have the potential to yield energy savings of 56 to 203 billion kWh and to reduce annual carbon emissions by 60 to 211 million tons CO_2.[91]

[91] For details on the energy savings calculations, refer to *The Green Grid: Energy Savings & Carbon Emissions Reductions Enabled by a Smart Grid.* EPRI, Palo Alto, CA: 2008. 1016905.

Table 14-3
Potential Smart Grid–enabled kWh and CO_2 Savings in the U.S. (2030)

Emissions-Reduction Mechanism Enabled by Smart Grid		Energy Savings, 2030 (billion kWh)		Avoided CO2 Emissions, 2030 (Tg CO2)	
		Low	*High*	*Low*	*High*
1	Continuous Commissioning of Large Commercial Buildings	2	9	1	5
2	Reduced Line Losses (Voltage Control)	4	28	2	16
3	Energy Savings Corresponding to Peak Load Management	0	4	0	2
4	Direct Feedback on Energy Usage	40	121	22	68
5	Accelerated Deployment of Energy Efficiency Programs	10	41	6	23
6	Greater Integration of Renewables	--	--	19	37
7	Facilitation of Plug-in Hybrid Electric Vehicles (PHEVs)	--	--	10	60
	Total	**56**	**203**	**60**	**211**

Carbon Taxes and Trading Systems

The consensus of the scientific community that there is a link between human-caused greenhouse gas emissions and climate change is growing. Public consciousness of this relationship is at an all-time high and, as a result, consumers are poised to make changes to reduce their personal carbon footprints. Although the US government has mainly promoted voluntary emissions reductions, policies are beginning to emerge that will mandate change.

As mentioned in Chapter 1, for example, California has passed legislation (Assembly Bill 32) to roll back carbon emissions to 1990 levels by the year 2020. In addition, Governor Charlie Crist of Florida issued Executive Order 07-127 on July 13, 2007 following a recent Climate Change summit laying down specific limits for greenhouse gas emissions by electric utilities: 2000 levels by 2017; 1990 levels by 2025; and 80 percent of 1990 levels by 2050. Two potential new directions for reducing greenhouse gas emissions are carbon taxes and carbon trading systems. Though not currently implemented in the US, both of these strategies have already been invoked in Europe.

A carbon tax is essentially a tax on the carbon dioxide emissions resulting from combustion of a fuel. This tax would likely be paid upstream by energy producers and then ultimately passed on to consumers as market conditions permit. In a carbon trading system, a central authority establishes limits (or caps) on the amount of carbon dioxide emissions allowed by a given entity. The entity is given a certain number of emissions credits to represent their allowable emissions. If they have excess emissions credits, they can sell them to other entities who need extra

allowances, and vice versa. This buying and selling of emissions credits is referred to as carbon trading. It rewards low emitters and penalizes high emitters. Mitigating greenhouse gas emissions through carbon reduction requirements is likely to impact the future design of energy efficiency programs.

While the causal link between energy efficiency and greenhouse gas reduction is self evident and well recognized, EE projects or programs have not been widely accepted by existing carbon emissions trading or offset markets as eligible categories for market participation. For example, the European Union Emission Trading Scheme, the largest multi-national emissions trading program in the world, does not include EE as an eligible category for greenhouse gas emissions abatement credit. The reasons why EE is largely excluded from greenhouse gas trading or offset markets—including challenges in baseline determination, EM&V rigor, and marginal emissions impact—are explained in another EPRI study.[92] EPRI is developing a modeling framework to quantify the marginal greenhouse gas reduction impact of EE measures that addresses the barriers oft cited by emissions trading markets. The objective of this activity is to establish a technically credible basis by which EE can be recognized and credited for its greenhouse gas reduction impacts to a level of analytical rigor sufficient for domestic and international emissions trading or offset markets.

Dynamic Energy Management

A new strategy for optimizing energy efficiency is to integrate traditional energy conservation programs with demand response efforts. EPRI refers to this as *Dynamic Energy Management*. In essence, Dynamic Energy Management is an innovative approach to managing load at the demand-side. It incorporates the conventional energy use management principles represented in energy efficiency, demand response, and distributed energy resource programs and merges them in a framework that simultaneously addresses permanent energy savings, permanent demand reductions, and temporary peak load reductions.

The Dynamic Energy Management framework can be regarded as an application of a Smart Grid infrastructure, as previously discussed. It would comprise an integrated system of smart and energy-efficient end-use devices and distributed energy resources with highly advanced controls and communications capabilities that enable dynamic management of whole building or home *system*. This simultaneous implementation of measures sets this approach apart from conventional EE programs and eliminates any inherent inefficiency that may otherwise arise from a piecemeal deployment strategy of energy efficiency, demand response, and other types of energy management alternatives. Designing a Dynamic Energy Management policy or program upfront optimizes the energy efficiency potential.

Dynamic Energy Management consists of four main components:

- Smart energy efficient end-use devices
- Smart distributed energy resources
- Advanced whole-building control systems

[92] *Giving Credit Where Credit is Due: Energy Efficiency in CO_2 Emissions Trading*. EPRI. Palo Alto, CA: 2008. 1016903.

- Integrated communications architecture

Figure 14-6 illustrates how these components act as building blocks of the Dynamic Energy Management concept. The components build upon each other and interact with one another to contribute to an infrastructure that is dynamic, fully-integrated, highly energy-efficient, automated, and capable of learning. The result is an infrastructure comprised of individual elements that are capable of working in unison to optimize operation of the integrated system based on consumer requirements, utility constraints, available incentives, and other variables such as weather and building occupancy.



Figure 14-6
Building Blocks of Dynamic Energy Management

The following points summarize the predominant characteristics of each of these four components.

Smart Energy Efficient End-Use Devices

- Appliances, lighting, space conditioning, and industrial process equipment with the highest energy efficiencies technically and economically feasible
- Thermal energy storage systems that allow for load shaping
- Intelligent end-use devices equipped with embedded features allowing for two-way communications and automated control
- Devices that represent an evolution from static devices to dynamic devices with advancements in distributed intelligence (one example is a high efficiency, internet protocol (IP) addressable appliance that can be controlled by external signals from the utility, end-user, or other authorized entity)

Smart Distributed Energy Resources

- Onsite generation devices such as photovoltaics, diesel engines, micro-turbines, and fuel cells that provide power alone or in conjunction with the grid
- Onsite electric energy storage devices such as batteries and fly wheels
- Devices that are dynamically controlled to supply base load, peak shaving, temporary demand reductions, or power quality
- Devices that are dynamically controlled such that excess power is sold back to the grid

Advanced Whole-Building Control Systems

- Control systems that optimize the performance of end-use devices and distributed energy resources based on operational requirements, user preferences, and external signals from the utility, end-user, or other authorized entity
- Controls that ensure end-use devices only operate as needed (examples include automatic dimming of lights when daylighting conditions allow or reducing outdoor ventilation during periods of low occupancy)
- Controls that allow for two-way communications (for example, they can send data to an external source and they can accept commands from an external source)
- Local, individual controls that are mutually compatible with a whole-building control system (for example, security, lighting, space conditioning, appliances, distributed energy resources, etc. can all be controlled by a central unit)
- Controls that have the ability to learn from past experience and apply that knowledge to future events

Integrated Communications Architecture

- Allow automated control of end-use devices and distributed energy resources in response to various signals such as pricing or emergency demand reduction signals from the utility, day-ahead weather forecasts, other external alerts, and end-user signals
- Allow the end-use devices, distributed energy resources, and/or control systems to send operational data to external parties
- Communications systems that have an open architecture to enable interoperability and communications among devices

Figure 14-7 shows an example of the Dynamic Energy Management infrastructure applied to a generic building. In this example there are two-way communications via the Internet as well as via the power line. The building is equipped with smart energy efficient end-use devices, an energy management system (EMS), automated controls with data management capabilities, and distributed energy resources such as solar photovoltaics, wind turbines, and other onsite generation and storage systems. Thus, energy efficient devices, controls, and demand response strategies are coupled with onsite energy sources to serve as an additional energy ‘resource’ for the utility. Not only do all of these elements contribute to the utility’s supply-side by reducing building demand, the distributed energy resources can also feed excess power back to the grid.

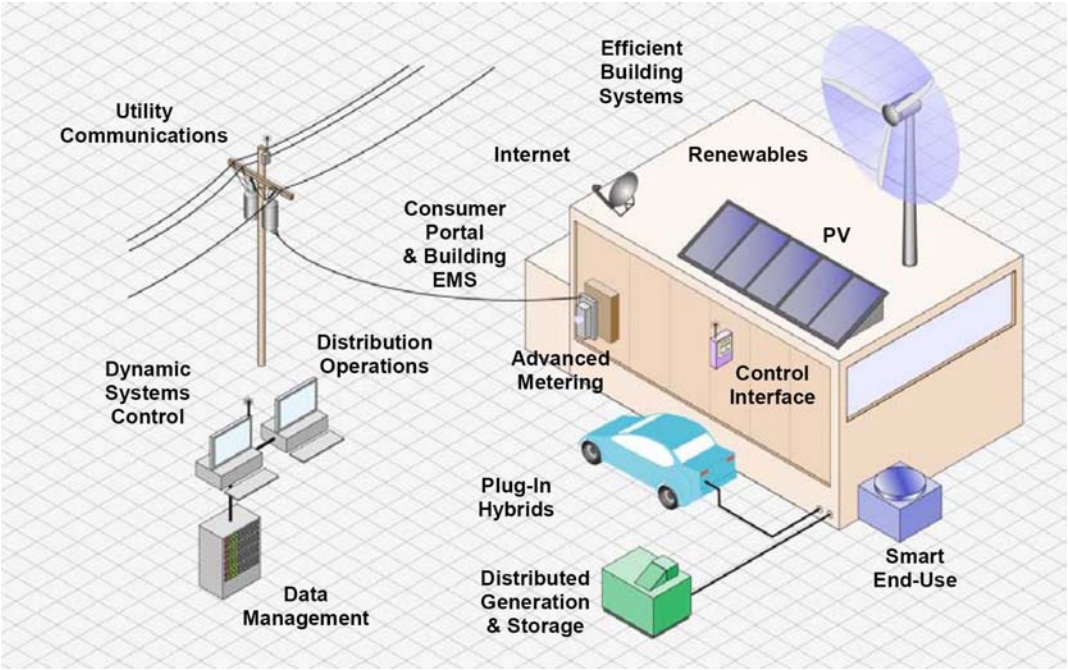


Figure 14-7
Dynamic Energy Management Infrastructure Applied to a Generic Building

A Dynamic Energy Management system is likely to have a much larger impact on a building's electricity consumption and demand than just implementing energy efficiency and/or demand response on their own. Figure 14-8 on the next several pages illustrates this point for an office building in the U.S.

Dynamic Energy Management Applied to a Hypothetical Office Building

Modeling Scenarios and Assumptions

In this example, a DOE-2 model of a new office building in Atlanta, Georgia is simulated under several different scenarios in order to evaluate the building's electricity consumption and demand under each scenario. The scenarios are: (1) the Base Case Scenario that represents 'business as usual,' (2) the Energy Efficiency Scenario that represents the installation and implementation of energy efficiency measures that are typically promoted in utility energy efficiency programs, (3) the Demand Response (DR) Scenario that represents the implementation of manual demand response strategies during extremely warm summer days, (4) the Combination Scenario that represents the simultaneous implementation of both energy efficiency and demand response as defined by #2 and #3 above, and (5) the Dynamic Energy Management Scenario that represents the implementation of Dynamic Energy Management technologies and strategies. Only measures and strategies that affect the lighting and cooling end-uses are included in the modeling of these scenarios. (For more information on the modeling procedure and parameters used in this example, please refer to *Dynamic Energy Management*, EPRI, Palo Alto, CA: 2007). The table below describes the strategies that were modeled in the base case and each of the scenarios.

Specific Strategies Modeled Under Different Scenarios

Measure/ Strategy	Energy Efficiency Scenario	Demand Response Scenario	Combination of Energy-Efficiency and Demand Response Scenario	Dynamic Energy Management Scenario
1. Cooling	Involves installing a higher-efficiency chiller than standard practice.	Involves manually setting the cooling setpoint to 79 F during a DR event. According to the Auto DR pilot project conducted in PG&E's service territory, approximately 10% of an office building's total demand can be reduced by implementing this strategy.	Involves installing a higher-efficiency chiller than standard practice. Also involves manually setting the cooling setpoint to 79 F during a DR event.	Involves installing the highest-efficiency chiller available. Also involves manually setting the cooling setpoint to 79 F during 10 critical peak pricing days and/or DR events throughout the year.
2. Envelope Insulation	Involves installing a higher-efficiency ceiling and roof insulation than standard practice.		Involves installing a higher-efficiency ceiling and roof insulation than standard practice.	Involves installing a higher-efficiency ceiling and roof insulation than standard practice.
3. Windows/ Glazing	Involves installing Low-E glazing.		Involves installing Low-E glazing.	Involves installing Low-E glazing.

(The Figure is continued on the following page)

Figure 14-8
Dynamic Energy Management Applied to a Hypothetical Office Building

Measure/ Strategy	Energy Efficiency Scenario	Demand Response Scenario	Combination of Energy-Efficiency and Demand Response Scenario	Dynamic Energy Management Scenario
4. Lighting	Involves implementing typical lighting measures such as T-5 lamps, super T-8 lamps, compact fluorescent lamps, task lighting, occupancy sensors, and time clocks and controls.	Includes manually turning off lights completely in unused areas and manually turning off a portion of lights in other areas ("bi-level switching") during a DR event. Assumes that 15% of lighting power can be reduced by implementing these strategies.	Involves implementing typical lighting measures such as T-5 lamps, super T-8 lamps, compact fluorescent lamps, task lighting, occupancy sensors, and time clocks and controls. Also involves manually turning off lights completely in unused areas and manually turning off a portion of lights in other areas ("bi-level switching") during a DR event.	Involves implementing typical lighting measures such as T-5 lamps, super T-8 lamps, compact fluorescent lamps, task lighting, dimmable ballasts, occupancy sensors, and time clocks. Additionally, advanced lighting controls are used to integrate daylighting into lamp dimming schemes. Also the advanced lighting controls will automate the process of dimming and/or turning off lights during 10 critical peak pricing and/or DR events throughout the year. Assumes that 30% of lighting power can be reduced by implementing these strategies.
5. Other	Includes optimizing set points of zone thermostats and cooling system operation schedules.		Includes optimizing set points of zone thermostats and cooling system operation schedules.	Includes optimizing set points of zone thermostats and cooling system operation schedules, automation of the chilled water and condenser water reset functions, and automation of pre-cooling the building in anticipation of warm days throughout the year. During 10 critical peak pricing and/or DR events during the year, the control system will also automatically implement the following strategies: increase thermostat set points (as described in #1 above), increase duct static pressure, increase chilled water temperature, and limit the distribution VSD fan speed. According to the Auto DR pilot project conducted in PG&E's service territory, approximately 15% of an office building's total demand can be reduced by implementing these strategies.

Results

Scenario	Base Case		Energy Efficiency/Demand Response/Dynamic Energy Management Implementation		Savings			
	kWh/yr	kW	kWh/yr	kW	kWh/yr	%	kW	%
Energy Efficiency Scenario	1,317,350	365 [1]	1,014,762	284 [1]	302,588	23%	81 [2]	22%
Demand Response Scenario	1,317,350	365 [1]	1,317,350 [3]	312 [1]	0 [3]	0%	53 [2]	15%
Energy Efficiency + Demand Response Scenario	1,317,350	365 [1]	1,014,762 [3]	243 [1]	302,588 [3]	23%	122 [2]	33%
Dynamic Energy Management Scenario	1,317,350	365 [1]	844,877	185 [1]	472,473	36%	180 [2]	49%

Notes:
1. This is the average electricity demand of the entire building during the three warmest weekdays of the summer (June 30 to July 2 of the typical meteorological year [TMY] climate data) between the hours of 2pm and 5pm.
2. This is the average electricity demand reduction of the entire building during the three warmest weekdays of the summer (June 30 to July 2 of the TMY climate data) between the hours of 2pm and 5pm.
3. Assumes that the energy savings due to demand response measures are negligible.

Figure 14-8 (continued)
Dynamic Energy Management Applied to a Hypothetical Office Building

The modeling of the office building indicates that implementing energy efficiency measures would result in electricity savings of 23% and a peak demand reduction of 22% relative to the base case. Implementing demand response strategies without implementing any energy efficiency measures would result in a peak demand reduction of 15% relative to the base case. (Energy savings due to demand response strategies are considered negligible because demand response actions are implemented during only a few emergency events throughout the year.) Using this same assumption, implementing a combination of energy efficiency and demand response in the same building would result in the same amount of electricity savings as the energy efficiency scenario (23%), but peak demand reduction would increase to 33% relative to the base case. The modeling results indicate that implementing Dynamic Energy Management would achieve a higher level of energy savings and demand reduction than implementing energy efficiency or demand response alone (or even the combination of the two). Implementing Dynamic Energy Management would result in an electricity savings of 36% and a peak demand reduction of 50% relative to the base case.

The important point here is that Dynamic Energy Management serves to fill in the gap and captures additional energy savings and demand reduction potential that would not otherwise be captured by implementing energy efficiency and demand response alone.

Source: *Dynamic Energy Management,* EPRI, Palo Alto, CA: 2007.

Figure 14-8 (continued)
Dynamic Energy Management Applied to a Hypothetical Office Building

The Future of Demand Response at RTOs

Over the last ten years RTOs have become an important institution in the wholesale electric power markets comprising around 60% to 70% of peak demand. With the enactment of the Energy Policy Act of 2005 there has been increasing emphasis on demand-side measures including the development of an active FERC role in encouraging demand response at RTOs. As a result, it is expected that the role of RTOs in demand response will expand.[93]

Currently, all of the RTOs in the U.S. are in a process of seeking enhancements to their demand response capabilities. Participation in ancillary services markets is a particular focus at NE-ISO and NYISO. CAISO's emerging MRTU[94] model is working to incorporate demand response in a more integrated fashion. MISO currently has a broad based initiative to develop demand response in its markets, and along with PJM is working to incorporate demand response into its planning process. ERCOT's emphasis at this time is incorporation of demand response into its nascent nodal market model. More broadly, this is likely to be an important issue across RTOs given that demand response resources are generally treated as demand with reference to demand zones, as opposed to "virtual generation" with reference to generation's commercial settlement nodes. SPP has started to examine the possibility of incorporating demand response into its balancing market.

[93] While it is difficult to predict whether RTOs will ten years hence cover more of the U.S., it seems likely that the RTOs—whether expanded or contracted—will have a bigger footprint in demand response than they do now.
[94] Market Reform and Technology Upgrade

Over the long run, issues that RTOs face in incorporating demand response include:

- Technology and communication standards. Demand response will be facilitated if there are common standards both within a given RTOs but especially nationally for metering and communication protocols. Several RTOs have cited this as an obstacle for them to overcome.[95]
- The role of "subsidies" to pay for demand response because of market failures. Demand response can result in significant social benefits that some maintain are not otherwise accounted for in current markets, such as overall reduction of capacity requirements, lowering of the market energy price, and lowering of emissions. In the absence of a market that reflects costs, a question for market design is whether demand response should receive payments beyond those received by generation?
- Resolution of the federal-state or wholesale-retail interface will be crucial in promoting demand response at both levels.
- Participation of aggregators in markets is a key factor in some jurisdictions such as California.
- The ability of demand response providers, whether utilities or aggregators, to provide consistent price signals to end users even when market prices are low.

Summary and Resources

This chapter has discussed the renewed drivers for energy efficiency and has described how these drivers are moving the energy industry in new directions.

Resources

A Renewed Mandate for Energy Efficiency, Discussion Paper, Prepared for the Attendees of the End-Use Electric Energy Efficiency Workshop: Serving Customer Power and Energy Needs in a Carbon-Constrained World, By Clark W. Gellings, EPRI, Palo Alto, CA: October 2007.

A Survey Of Time-of-Use (TOU) Pricing and Demand-Response (DR) Programs, prepared for the U.S. Environmental Protection Agency, prepared by Energy & Environmental Economics, San Francisco, CA: July 2006.

An Assessment of Distribution System Power Quality, Volume 2: Statistical Summary Report. EPRI, Palo Alto, CA, January 1998. TR-106294.

Annual Energy Outlook 2005, With Projections to 2025, Energy Information Administration, Office of Integrated Analysis and Forecasting, U.S. Department of Energy, Washington, DC: January 2005.

Annual Energy Outlook 2007, With Projections to 2030, Energy Information Administration, Office of Integrated Analysis and Forecasting, U.S. Department of Energy, Washington, DC: February 2007.

[95] See, for example, Robert Earle and Ahmad Faruqui, *Demand Response and the Role of Regional Transmission Operators.* Global Energy Partners—Demand Response Application Service. 2006.

Commercial Building Energy Efficiency and Efficient Technologies Guidebook. EPRI, Palo Alto, CA: 2008. 1016112.

Demand Response and the Role of Regional Transmission Operators. Robert Earle and Ahmad Faruqui. Global Energy Partners—Demand Response Application Service. 2006.

Dynamic Energy Management, EPRI, Palo Alto, CA: 2007.

EPRI's Contribution to the Development of PHEV Technology, EPRI, Palo Alto, CA: November 2007. 1014887.

Facilitating the Transition to a Smart Electric Grid, Testimony of Audrey Zibelman, PJM Chief Operating Officer and Executive Vice President, before U.S. House of Representatives Committee on Energy and Commerce, May 3, 2007.

Plug-in Hybrid Electric Vehicles: Changing the Energy Landscape, EPRI, Palo Alto, CA: May 2005. 1011996.

The Galvin Electricity Initiative, Task 2—Potential for End-Use Energy Technologies to Improve Functionality and Meet Consumer Expectations, EPRI, Global Energy Partners, LLC, and EPRI Solutions, Inc.: 2006.

The Green Grid: Energy Savings & Carbon Emissions Reductions Enabled by a Smart Grid. EPRI, Palo Alto, CA: 2008. 1016905.

The Power to Reduce CO_2 Emissions: The Full Portfolio, Discussion Paper, Prepared for the EPRI 2007 Summer Seminar Attendees, By The EPRI Energy Technology Assessment Center, EPRI, Palo Alto, CA: August 2007.

UPS-Substation™: Evaluation, Conceptual Design, and Generic Specification. EPRI, Palo Alto, CA: 1998. TR-111091.

A
NEW EXPERIMENTAL EVIDENCE ON DYNAMIC PRICING

This appendix compares the results of the following fourteen recent pilots and studies on dynamic pricing carried out in the United States, Canada, France, and Australia: [96,97]

- **California—**Anaheim Critical Peak Pricing Experiment.
- **California—**California Automated Demand Response System Pilot (ADRS)
- **California—**California Statewide Pricing Pilot (SPP)
- **Florida—**Gulf Power Select Program
- **France—**Electricite de France (EDF) Tempo Program
- **Idaho—**Idaho Residential Pilot Program
- **Illinois—**The Community Energy Cooperative's Energy-Smart Pricing Plan (ESPP)
- **Missouri—**AmerenUE Residential TOU Pilot Study
- **New Jersey**—GPU Pilot
- **New Jersey—**Public Service Electric and Gas (PSE&G) Residential Pilot Program
- **New South Wales / Australia—**Energy Australia's Network Tariff Reform
- **Ontario/Canada—**Ontario Energy Board Smart Price Pilot
- **Washington, Seattle**—Puget Sound Energy's TOU Program
- **Washington and Oregon—**Olympic Peninsula Project

To provide historical perspective, these results are compared to time-of-use pricing pilots that were carried out under the auspices of the U.S. DOE and its predecessor agency, the Federal Energy Administration, during the 1970s and 1980s, as summarized in the following two studies:

- "Consistency of Residential Customer Response in Time-of-Use Electricity Pricing Experiments." 1984.
- "The Residential Demand for Electricity by Time-of-Use: A Survey of Twelve Experiments with Peak Load Pricing." 1983.

[96] The research developed for this appendix is also featured in a discussion paper by The Brattle Group entitled *The Power of Experimentation: New Evidence on Residential Demand Response*.

[97] We use the term "dynamic pricing" to refer to pricing signals that are triggered based on actual wholesale market prices and not set in advance. Thus, a time of use (TOU) rate is not a dynamic price, since the peak period is known in advance, whereas under critical peak pricing (CPP), although the rate may be set in advance, the critical days are called based on wholesale market conditions.

A review of these dynamic pricing pilots reveals that dynamic prices are effective in reducing electricity usage. In general, critical peak pricing (CPP) programs supported with enabling technologies result in the largest reductions in load. However, CPP programs alone (without an enabling technology) also achieve significant reductions in load. TOU programs without enabling technologies reduce load somewhat; however, when TOU programs are supported with enabling technologies, the average load reduction is larger. Based on the pilot results, the combination of dynamic prices with enabling technologies appears to be the most effective program design for reducing electricity usage during high-priced periods. A summary of the impacts associated with the pilots reviewed in this sidebar are shown in Figure A-1.

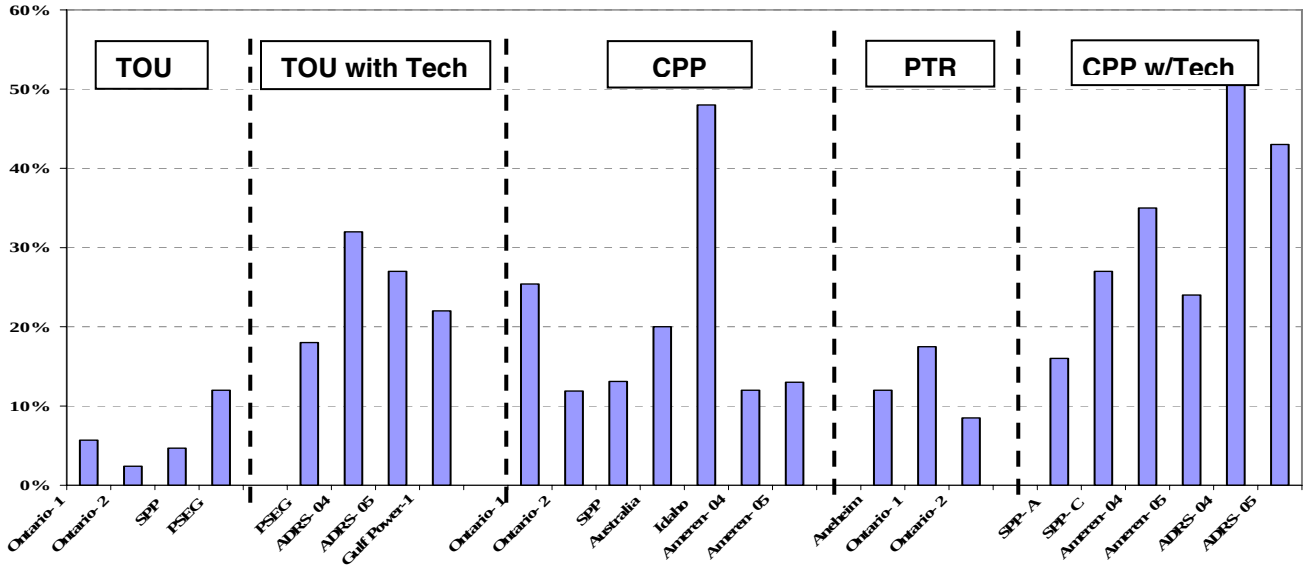


Figure A-1
Estimates of Percentage Reduction in Load from the Pilots Reviewed

Notes:
*Percentage reduction in load is defined relative to the different bases in different pilots. Following notes are intended to clarify these different definitions. TOU impacts are defined relative to the usage during peak hours unless otherwise noted. CPP impacts are defined relative to the usage during peak hours on CPP days unless otherwise is noted.

1- Ontario- 1 refers to the percentage impacts during the critical hours that represent only 3-4 hours of the entire peak period on a CPP day. Ontario- 2 refers to the percentage impacts of the programs during the entire peak period on a CPP day.
2- TOU impact from the SPP study uses the CPP-F treatment effect for normal weekdays as recommended by the study.
3- PSEG programs are represented in the TOU section even though they are CPP programs, because there were only 2 CPP events during the entire pilot period and more importantly % impacts were only provided for the peak period on non-CPP days.
4- ADRS- 04 and ADRS- 05 refer to the 2004 and 2005 impacts. ADRS impacts on non-event days are represented in the TOU with Tech section.
5- CPP impact for Idaho is derived from the information provided in the study. Average of kW consumption per hour during the CPP hours (for all 10 event days) is approximately 2.5kW for a control group customer. This value is 1.3kW for a treatment group customer. Percentage impact from the CPP treatment is calculated as 48%.
6- Gulf Power-1 refers to the impact during peak hours on non-CPP days while Gulf Power- 2 refers to the impact during CPP hours on CPP days.
7- Ameren- 04 and Ameren- 05 refer to the impacts respectively from the summers of 2004 and 2005.
8- SPP- A refers to the impacts from the CPP-V program on Track A customers. Two thirds of Track A customers had some form of enabling technologies.
9- SPP- C refers to the impacts from the CPP-V program on Track C customers. All Track C customers had smart thermostats.

Figure A-2 shows the twelve North American pilot programs reviewed in this appendix.

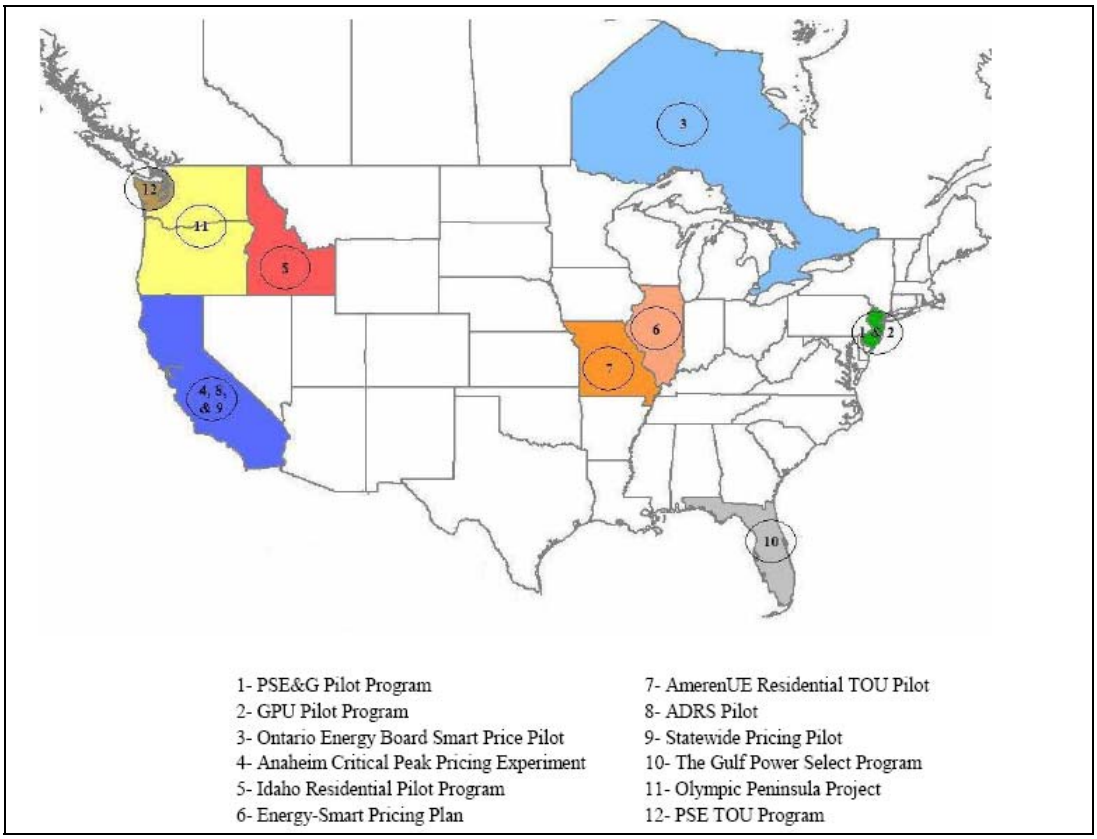


Figure A-2
Geographic Coverage of the North America Pilot Programs Reviewed

California—Anaheim Critical Peak Pricing Experiment

The City of Anaheim Public Utilities (APU) conducted a residential Critical Peak Pricing Experiment between June 2005 and October 2005.[98] A total of 123 customers participated in the experiment: 52 in the control group and 71 in the treatment group. The CPP rate rewarded participants with a rebate of $0.35 for each kWh reduction below the reference level peak-period consumption on non-CPP days (i.e., the baseline consumption). Table A-1 presents the rate design.

[98] Wolak, Frank A., "Residential Customer Response to Real-Time Pricing: Anaheim Critical Peak Pricing Experiment," UCEI and Department of Economics, Stanford and NBER, 2007.

Table A-1
Anaheim CPP Program Rate Design

Group	Charge	Applicable
Control	Standard increasing-block residential tariff: $0.0675/kWh if consumption <=240kWh per month $0.1102/kWh if consumption >240kWh per month	All Hours
Treatment	Standard increasing-block residential tariff	All Hours except except peak hours (12 a.m. - 6 p.m.) on CPP days
Treatment	$0.35 rebate for each kWh reduction relative to their typical peak consumption on non-CPP days.	Peak hours (12 a.m. - 6 p.m.) on CPP days

Source: Anaheim Critical Peak Pricing Experiment, page 1-2.

The results show that:

- The treatment group used 12% less electricity on average during the peak hours of the CPP days than the control group.
- The reduction in consumption by customers in the treatment group was greater on higher temperature CPP days.

California—Automated Demand Response System Pilot[99]

California's Advanced Demand Response System (ADRS) pilot program was initiated in 2004 and extended through the end of 2005. ADRS operated under a critical peak pricing tariff which was supported with a residential-scale, automated demand response technology. Participants of the pilot installed the "GoodWatts" system, an advanced home climate control system that allowed users to web-program their preferences for the control of home appliances. Under the CPP tariff, prices were higher during the peak period (2 p.m. to 7 p.m. on weekdays). All other hours, weekends and holidays were subject to the base rate. When the "super peak events" were called, peak price was three times higher than the regular peak price.

The results from the pilot show that:

- Participants achieved substantial load reductions in both 2004 and 2005 compared to the control group.
- Load reductions on super peak event days were consistently about twice the load reductions during the peak periods on non-event days.
- Technology appears to be the main driver of the load reductions especially on super peak event days and for the high consumption customers.
- Part of the reduction is attributable to time-varying rates. However, the load reductions of the ADRS participants are consistently larger than those of the participants of other demand response programs without the technology.

[99] Rocky Mountain Institute, "Automated Demand Response System Pilot," 2006.

Table A-2 shows the impact estimates from the ADRS for high consumption customers.

Table A-2
California ADRS Peak Period Load Reductions for High Consumption Customers

	Event Days		Non-Event Days	
Program Year	**Average Reduction (kW)**	**% Reduction**	**Average Reduction (kW)**	**% Reduction**
2004	1.84	51%	0.86	32%
2005	1.42	43%	0.73	27%

Source: ADRS Study, Executive Summary, pages 6,11.

California—Statewide Pricing Pilot[100]

California's three investor-owned utilities, together with the state's regulatory commission and state energy commission, conducted a Statewide Pricing Pilot (SPP) that ran from July 2003 to December 2004 to test the impact of several time-varying rates. The SPP involved about 2,500 participants, including residential and small-to-medium commercial and industrial (C&I) customers. SPP tested several rate structures:

- TOU-only rate where the peak price was twice the value of the off-peak price.
- CPP rate where the peak price during the critical days was roughly five times greater than the off-peak price. The SPP tested two variations of the CPP rates.
  - The CPP-F rate had a fixed period of critical peak and day-ahead notification. CPP-F customers did not have an enabling technology.
  - The CPP-V rate had a variable-length of peak duration during critical days and day-of notification. CPP-V customers had the choice of adopting an enabling technology.

The SPP utilized demand models to identify the impact of different rate and information structures on energy use. In addition to estimation of impacts associated with the average prices used in SPP, these demand models allowed estimation of the impacts from other potential prices. A demand system of two equations was estimated for each different rate structure. One of these equations estimates daily energy use while the other predicts the share of daily energy use by rate period.

In this appendix, we review the residential customer impacts for the three rates: CPP-F, TOU, and CPP-V.

[100] Charles River Associates, "Impact Evaluation of the California Statewide Pricing Pilot." 2005.

CPP-F Impacts

The average price for customers on the standard rate was about $0.13 per kWh. Under the CPP-F rate, the average peak-period price on critical days was roughly $0.59 per kWh, the peak price on non-critical days was $0.22 per kWh, and the average off-peak price was $0.09 per kWh.

- On critical days, statewide average reduction in peak-period energy use was estimated to be 13.1 percent. Impacts varied across climate zones from a low of -7.6 percent to a high of -15.8 percent.
- The average peak-period impact on critical days during the inner summer months (July-September) was estimated to be -14.4 percent while the same impact was -8.1 percent during the outer summer months (May, June, and October).
- On normal weekdays, the average impact was -4.7 percent, with a range across climate zones from -2.2 percent to -6.5 percent.
- No change in total energy use across the entire year was found based on the average SPP prices.
- The impact of different customer characteristics on energy use by rate period was also examined. Central AC ownership and college education are the two customer characteristics that were associated with the largest reduction in energy use on critical days.

Table A-3
Residential CPP-F Rate Impacts on Critical Days, All Customers (July – September)

		Start Value (kWh/hr)	Impact (kWh/hr)	Estimate	t-stat	Impact (%)
		2003				
Rate Period	Peak	1.28	-0.163	#N/A	-20.94	-12.71
	Off-peak	0.8	0.021	#N/A	7.8	2.57
	Daily	0.9	-0.018	#N/A	-6.88	-1.95
Elasticity	Substitution	#N/A	#N/A	-0.086	-20.51	#N/A
	Daily	#N/A	#N/A	-0.032	-6.8	#N/A
		2004				
Rate Period	Peak	1.28	-0.178	#N/A	-18.49	-13.93
	Off-peak	0.8	0.01	#N/A	2.95	1.25
	Daily	0.9	-0.029	#N/A	-8.7	-3.24
Elasticity	Substitution	#N/A	#N/A	-0.087	-16.84	#N/A
	Daily	#N/A	#N/A	-0.054	-8.55	#N/A

Source: Impact Evaluation of the California Statewide Pricing Pilot, pages 51-52.
Notes:
[1] Estimations are based on average customer approach.
[2] All the numbers are based on average critical day weather in 2003/2004.

TOU Impacts

The average price for customers on the standard rate was about $0.13 per kWh. Under the TOU rate, the average peak-period price was roughly $0.22 per kWh and the average off-peak price was $0.09 per kWh.

- The reduction in peak period energy use during the inner summer months of 2003 was estimated to be -5.9 percent. However, this impact completely disappeared in 2004.
- Due to small sample problems in the estimation of TOU impacts, normal weekday elasticities from the CPP-F treatment may serve as better predictors of the impact of TOU rates on energy demand than the TOU price elasticity estimates.

Table A-4
Residential TOU Rate Impacts for Innner Summer Months for All Customers

		Start Value (kWh/hr)	Impact (kWh/hr)	Estimate	t-stat	Impact (%)
		2003				
Rate Period	Peak	1.125	-0.063	#N/A	-11.08	-5.6
	Off-peak	0.744	0.011	#N/A	7.08	1.44
	Daily	0.823	-0.005	#N/A	-6.28	-0.57
	Weekend Daily	0.867	0.013	#N/A	4.46	1.45
Elasticity	Substitution	#N/A	#N/A	-0.099	-10.17	#N/A
	Daily	#N/A	#N/A	-0.117	-6.26	#N/A
	Weekend Daily	#N/A	#N/A	-0.066	-4.49	#N/A
		2004				
Rate Period	Peak	1.125	-0.007	#N/A	#N/A	-0.6
	Off-peak	0.744	-0.005	#N/A	#N/A	-0.65
	Daily	0.823	-0.005	#N/A	#N/A	-0.64
	Weekend Daily	0.867	0.005	#N/A	#N/A	0.61
Elasticity	Substitution	#N/A	#N/A	0.001	0.06	#N/A
	Daily	#N/A	#N/A	-0.132	-4.42	#N/A
	Weekend Daily	#N/A	#N/A	-0.028	-1.36	#N/A

Source: Impact Evaluation of the California Statewide Pricing Pilot, pages 92,95, and 96.
Notes:
[1] Estimations are based on average customer approach.

CPP-V Impacts

The average price for customers on the standard rate was about $0.14 per kWh. Under the CPP-V rate, the average peak-period price on critical days was roughly $0.65 per kWh and the average off-peak price was $0.10 per kWh. This rate schedule was tested on two different treatment groups. Track A customers were drawn from a population with energy use greater than 600kWh per month. In this group, average income and central AC saturation was much higher than the general population. Track A customers were given a choice of installing an

enabling technology and about two thirds of them opted for the enabling technology. The Track C group was formed from customers who previously volunteered for a Smart thermostat pilot. All Track C customers had central AC and smart thermostats. Hence, two-thirds of Track A customers and all Track C customers had enabling technologies.

- As shown in Table A-5, Track A customers reduced their peak-period energy use on critical days by about 16 percent (about 25 percent higher than the CPP-F rate impact).
- Track C customers reduced their peak-period use on critical days by about 27 percent.

Comparing the CPP-F and the CPP-V results suggest that usage impacts are significantly larger with an enabling technology than without it.

Table A-5
Residential CPP-V Rate Impacts for Summer for All Customers

		Start Value (kWh/hr)	Impact (kWh/hr)	Estimate	t-stat	Impact (%)
		Track A				
Rate Period	Peak	2.14	-0.3374	#N/A	-10.89	-15.76
	Off-peak	1.33	0.0445	#N/A	4.26	3.34
	Daily	1.46	-0.0187	#N/A	-1.71	-1.28
	Weekend Daily	1.3	0.0173	#N/A	2.72	1.33
Elasticity	Substitution	#N/A	#N/A	-0.111	-11.76	#N/A
	Daily	#N/A	#N/A	-0.027	-1.7	#N/A
	Weekend Daily	#N/A	#N/A	-0.043	-2.74	#N/A
		Track C				
Rate Period	Peak	2.33	-0.635	#N/A	-35.03	-27.23
	Off-peak	1.26	0.044	#N/A	3.19	3.52
	Daily	1.43	-0.059	#N/A	-9.85	-4.17
	Weekend Daily	1.34	0.016	#N/A	4.1	1.2
Elasticity	Substitution	#N/A	#N/A	-0.077	-10.61	#N/A
	Technology Impact-Substitution	#N/A	#N/A	-0.214	-24.04	#N/A
	Daily	#N/A	#N/A	-0.044	-3.49	#N/A
	Technology Impact-Daily	#N/A	#N/A	-0.019	-3.49	#N/A
	Weekend Daily	#N/A	#N/A	-0.041	-4.12	#N/A

Source: Impact Evaluation of the California Statewide Pricing Pilot, pages 105,106,109, and 110.
Notes:
[1] Estimations are based on average customer approach.
[2] Track A analysis was conducted for Summer 2004.
[3] Track C analysis pools summers 2003 and 2004 and estimates a single model.

Florida—The Gulf Power Select Program[101]

In 2000, Gulf Power started a unique demand response program that provides customers with three different service options as described below.

- The standard residential service (RS) pricing option which involved a standard flat rate with no time varying rates.
- A conventional TOU pricing option (RST) which is a two-period TOU tariff.
- The Residential Service Variable Price (RSVP) pricing option which is a three-period CPP tariff.

Under the RSVP option, the energy company provides the price signals and customers modify their usage patterns through a combination of the price signals and advanced metering and appliance control. Gulf Power markets the RSVP option under the GoodCents Select program and charges the participants a monthly participation fee. By the end of 2001, approximately 2,300 homes were served by the RSVP.

Table A-6 shows the rates under the Gulf Power demand response program.

Table A-6
Residential Residential Tariffs for Summer Months

Program	Period	Charge	Applicable
RS	Base	$0.057/kWh	All Hours
RST	Off-peak	$0.027/kWh	12 a.m.-12 p.m. and 9 p.m.-12 a.m.
RST	Peak	$0.104/kWh	12 p.m.- 9 p.m.
RSVP	Off-peak	$0.035/kWh	12 a.m.-6 a.m. and 11 p.m.-12 a.m.
RSVP	Mid-peak	$0.046 /kWh	6 a.m.-11 a.m. and 8 p.m.-11 p.m.
RSVP	Peak	$0.093/kWh	11 a.m.-8 p.m.
RSVP	CPP	$0.29/kWh	When called.

Source: Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets, Appendix B, page B-4.

Gulf Power reports the base coincident peak demand as 6.1 KW per household. RSVP program performance results presented in Table A-7 show that RSVP program participants reduce their demand by 2.75 KW per household during the critical peak period. This corresponds to a 41% reduction in energy usage during the critical peak period.

[101] Borenstein, S., M. Jaske, and A. Rosenfeld, "Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets", UCEI 2002.

Table A-7
RSVP Program Performance by Period

Demand Reduction by Period	Performance
Average demand reduction (during peak period)	2.1 kW/hh
Average demand reduction (during critical peak period)	2.75 kW/hh
Average energy reduction (during peak period)	22%
Average energy reduction (during critical peak period)	41%

Source: Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets, Appendix B, page B-8.

France—Electricite de France (EDF) Tempo Program[102]

Electricite de France (EDF) has initiated the Tempo program in 1996. Rate design entails two price-tiers, peak and off-peak. Distinctive feature of the Tempo program is the day-of-the-year pricing which groups 365 days in a year into three day-types:

- *Blue-days* are the least expensive days and cover 300 days.
- *White days* are moderately priced days and cover 43 days.
- *Red days* are the most expensive days and cover 22 days.

Customers can learn which day will be in effect the next day through the use of several resources including web-resources, call-centers, subscription to e-mail alerts, and a plug-in display device.

EDF implemented a pilot program before initiating Tempo on a full-scale. The pilot program set prices that were much higher than Tempo prices. Own-price elasticity for peak demand was estimated -0.79 and much higher than those estimated for U.S. pilots. Own-price elasticity for off-peak usage was estimated to be -0.18.

[102] Faruqui, A., S. George. 2002. "The Value of Dynamic Pricing in Mass Markets." *Electricity Journal* Vol.15.6: 45-55.

Idaho- Idaho Residential Pilot Program[103]

Idaho Power Company initiated two residential pilot programs in the Emmett area of Idaho in the summer of 2005 and the summer of 2006: Time-of-day (TOD) and Energy Watch (EW).

Time-of-Day Pilot

The TOD pilot was designed as a conventional TOU program where the participants were charged different rates by time of the day as shown in Table A-8. The TOD pilot included 85 treatment and 420 control group customers as of August 2006.

Table A-8
Rate Design for the Time-of-Day Pilot

Period	Charge	Applicable
On-Peak	$0.083/kWh	Weekdays from 1pm to 9pm
Mid-Peak	$0.061/kWh	Weekdays from 7am to 1pm
Off-Peak	$0.045/kWh	Weekdays from 9pm to 7am and all hours on weekends and holidays

Source: 2006 Analysis of the Residential TOD and EW Pilot Programs, page 1.

As shown in Table A-9, the results from the TOD pilot for the summer of 2006 show that, on average, the peak period percentage of total summer usage was the same for the treatment and control groups—about 22 percent. In fact, the percentage of usage during the mid-peak and off-peak periods was also the same between the two groups. This indicates that the TOD rates had no effect on shifting usage. However, given the very low ratio of on-peak to off-peak rates (about 1.84), this result is not so surprising. It indicates that a higher ratio of peak to off-peak rates is needed to induce customers to shift usage from peak to off peak periods.

Table A-9
Summer 2006 (June-August) Usage under the TOD Pilot

	Average Use (kWh)		% of Total Summer Use			
Period	**Treatment**	**Control**	**Treatment**	**Control**	**Difference**	**T-stat**
On-Peak	800	763	22%	22%	-36.46	0.66
Mid-Peak	591	568	16%	16%	-22.43	0.52
Off-Peak	2307	2162	62%	62%	-145.78	0.99
Summer 06 Usage	3698	3493	100%	100%	-204.67	0.87

Source: 2006 Analysis of the Residential TOD and EW Pilot Programs, page 14.

[103] Idaho Power Company, "2006 Analysis of the Residential Time-of-Day and Energy Watch Pilot Programs: Final

Energy Watch Pilot

The Energy Watch (EW) pilot was designed as a critical peak pricing (CPP) pilot where the participants were notified of the CPP event on a day-ahead basis. A total of 10 EW days were called during the summer of 2006. EW was designed as follows:

- CPP hours from 5 p.m. to 9 p.m.
- Day-ahead notification
- CPP energy price of $0.20/kWh
- Non-CPP energy price of $0.054/kWh

The EW pilot included 68 treatment and 355 control group customers as of August 2006.

Table A-10 shows the reduction in load (kW) on CPP days for each of the event days. Average hourly demand reduction ranged from 0.64 kW (on June 29) 1.70 kW (on July 27). Average hourly load reduction for all ten event days was 1.26 kW. The average total load reduction for a 4-hour event was 5.03 kW.

Table A-10
Energy Watch Day: Load Reductions (kW)

Hour Beginning	Hour Ending	29-Jun	11-Jul	14-Jul	18-Jul	19-Jul	25-Jul	27-Jul	3-Aug	9-Aug	15-Aug	Average
5pm	6pm	0.64	1.31	1.09	1.39	1.2	1.33	1.58	1.14	0.83	1.02	1.17
6pm	7pm	0.69	1.5	1.17	1.43	1.32	1.45	1.62	1.27	1.14	1.15	1.29
7pm	8pm	0.77	1.58	1.16	1.57	1.41	1.55	1.7	1.24	1.02	0.96	1.33
8pm	9pm	0.8	1.48	1.11	1.47	1.27	1.4	1.6	1.13	0.95	0.89	1.25
4-Hour Total		2.89	5.87	4.53	5.85	5.2	5.74	6.5	4.77	3.94	4.02	5.03
Average Hourly		0.72	1.47	1.13	1.46	1.3	1.43	1.62	1.19	0.99	1.01	1.26
Min Temp		68	65	65	61	62	75	68	59	62	67	65
Max Temp		85	100	98	94	98	99	104	92	85	92	95
Avg Temp		75	84	83	79	80	87	87	76	73	80	80

Source: 2006 Analysis of the Residential TOD and EW Pilot Programs, page 20.

Illinois—ENERGY-Smart Pricing Plan[104]

Community Energy Cooperative's Energy-Smart Pricing Plan (ESPP), a residential real-time pricing (RTP) program, started in Illinois in 2003. ESPP initially included 750 participants and expanded to nearly 1500 customers in 2005. ESPP is the only residential RTP program that has been tested at any scale. ESPP has a focus on low technology and tests the hypothesis that major benefits may result from RTP without expensive technology adoption. The ESPP design included:

- Day-ahead announcement of the hourly electricity prices for the next day (i.e., customers were charged the day ahead hourly prices)

Report," 2006.
[104] Summit Blue Consulting, "Evaluation of the 2005 Energy-Smart Pricing Plan-Final Report," 2006.

- High-price day notification via phone or email when the price of electricity is over $0.10 per kWh
- A price limit hedge of $0.50 per kWh for participants, meaning that the maximum hourly price is set at $0.50 per kWh during their participation in the program
- Energy usage education for participants

The main goals of the pilot were to determine the price elasticity of demand and the overall impact on energy conservation. A regression based analysis was conducted to estimate the price elasticity of demand for the summer months. Overall price elasticity was estimated to be -0.047. Automatic cycling of the central-air conditioners using an enabling technology during high-price periods increased the overall price elasticity to -0.069. The largest response occurred on high price notification days. For instance, on the day with the highest prices of the summer 2005, participants reduced their peak hour consumption by 15% compared to what they would have consumed under the flat ComEd residential rate. Price responsiveness varied over the course of a day. Price elasticities by time of the day are presented in Table A-11.

Table A-11
Elasticity Estimates from ESPP

Time of the Day	Elasticity Estimate
Daytime (8 a.m. to 4 p.m.)	-0.02
Late afternoon/evening hours (4 p.m. to midnight)	-0.03
Daytime+ High-Price Notification	-0.02
Late Daytime/Evening+High-Price Notification	-0.05

Source: Evaluation of the 2005 Energy-Smart Pricing Plan-Final Report, page 11.

Results of the energy impact analysis indicates that ESPP participants consumed 35.2 kWh less per month during the summer months compared to what they would have consumed without the ESPP. These savings represent roughly 3 to 4% of the summer electricity usage. No statistically significant savings were found for the winter usage which is not surprising since most high price days occur in the summer months in this area. Overall, ESPP resulted in a net decrease in monthly energy consumption.

Missouri—AmerenUE Critical Peak Pricing Pilot

First Year of the Pilot Program (2004)[105]

AmerenUE in collaboration with Missouri Collaborative—formed by Office of Public Counsel (OPC), the Missouri Public Service Commission (MPSC), the Department of Natural Resources (DNR) and two industrial intervener groups—started a residential TOU pilot study in Missouri during the spring of 2004. Program impacts associated with three different TOU programs were evaluated:

[105] RLW Analytics, "AmerenUE Residential TOU Pilot Study Load Research Analysis: First Look Results," 2004.

- TOU with peak, mid-peak, and off-peak rates
- TOU with a CPP component
- TOU with a CPP component and an enabling technology (smart thermostat)

Table A-12 shows the rates evaluated in the pilot.

Table A-12
Residential TOU Experiment Summer Rate Design

Program	Time	Charge	Applicable
TOU	Off Peak	$0.048/kWh	Weekday 10pm–10am, Weekends, Holidays
TOU	Mid Peak	$0.075/kWh	Weekdays 10am– 3pm and 7pm-10pm
TOU	Peak	$0.183/kWh	Weekday 3pm – 7pm
TOU-CPP	Off Peak	$0.048/kWh	Weekday 10pm–10am, Weekends, Holidays
TOU-CPP	Mid Peak	$0.075/kWh	Weekdays 10am– 3pm and 7pm-10pm
TOU-CPP	Peak	$0.168/kWh	Weekday 3pm – 7pm
TOU-CPP	CPP	$0.30/kWh	Weekday 3pm – 7pm, 10 times per summer

Source: AmerenUE Residential TOU Pilot Study Load Research Analysis: First Look Results, page 10.

Table A-13 shows the number of participants in the treatment and control groups by type of rate.

Table A-13
Experiment Sample Allocation

Treatment	Treatment Sample Size	Control Sample Size
TOU	88	89
TOU-CPP	85	89
TOU-CPP-Tech	77	117
Total	250	295

The following results are based on the data compiled from the pilot between June 1, 2004 and September 30, 2004. The results show that:

- Participants in the TOU and TOU-CPP group do not shift a statistically significant amount of load from the on-peak to off-peak or mid-peak periods. As shown in Table A-14, under both TOU and TOU-CPP programs, off-peak consumption increases and peak consumption decreases only slightly for treatment group compared to the control group. However, none of these differences in consumption between the treatment and control groups are statistically significant.
- Participants in the TOU-CPP-Tech group do shift a statistically significant amount of load from the on-peak to off-peak or mid-peak periods. As shown in Table A-15, the average treatment customer under this program increases off-peak consumption while decreasing mid-peak and peak consumption compared to the corresponding values for the control group. The difference is statistically significant.

Average consumption by participants during the pilot is provided in Tables A-14 and A-15.

Table A-14
Average Participant Use by Program and Pricing Time, 2004

Program	Time	Control Group (kWh)	Treatment Group (kWh)	Difference	t-test	Pr> |t|	Statistical Significance of the Difference
TOU	Off Peak	33.63	34.87	-1.24	-0.71	0.479	Not Significant.
TOU	Mid Peak	23.59	22.78	0.81	0.71	0.476	Not Significant.
TOU	On Peak	13.81	13.36	0.45	0.67	0.505	Not Significant.
TOU	Seasonal	60.00	60.34	-0.34	-0.12	0.905	Not Significant.
TOU-CPP	Off Peak	35.84	38.36	-2.52	-1.19	0.235	Not Significant.
TOU-CPP	Mid Peak	24.11	24.54	-0.43	-0.34	0.733	Not Significant.
TOU-CPP	On Peak	13.82	13.29	0.54	0.73	0.466	Not Significant.
TOU-CPP	CPP	19.8	18.85	0.95	0.86	0.390	Not Significant.
TOU-CPP	Daily	62.87	65.3	-2.43	-0.72	0.473	Not Significant.
TOU-CPP-Tech	Off Peak	37.61	33.31	4.3	2.44	0.002	Significant.
TOU-CPP-Tech	Mid Peak	25.86	22.47	3.39	3	0.003	Significant.
TOU-CPP-Tech	On Peak	14.86	12.77	2.09	3.09	0.002	Significant.
TOU-CPP-Tech	CPP	21.39	15.48	5.92	6.5	0.000	Significant.
TOU-CPP-Tech	Daily	66.63	58.28	8.35	2.88	0.000	Significant.

Source: AmerenUE Residential TOU Pilot Study Load Research Analysis: First Look Results page 17, 22, 28.

Table A-15
Average Usage on the 6 CPP Event Days in Summer 2004

Program	Control Group (kWh)	Treatment Group (kWh)	Difference	% Difference	t-test	Pr> |t|	Statistical Significance of the Difference
TOU-CPP	4.98	4.37	0.61	12%	2.09	0.038	Significant.
TOU-CPP-Tech	5.36	3.49	1.87	35%	8.09	0.000	Significant.

Source: AmerenUE Residential TOU Pilot Study Load Research Analysis: First Look Results page C.

Second Year of the Pilot Program (2005)[106]

During the second year of AmerenUE Critical Peak Pricing Pilot, the first year rate design described earlier remained in effect (see Table A-12). Table A-16 summarizes the usage impact on eight CPP days in the summer 2005.

Table A-16
Average Usage from on the 8 CPP Event Days in Summer 2005

Program	Control Group (kWh)	Treatment Group (kWh)	Difference	% Difference	t-test	Pr> |t|	Statistical Significance of the Difference
TOU-CPP	5.56	4.84	0.72	13%	3.9	0.0001	Significant.
TOU-CPP-Tech	5.29	4.05	1.14	24%	6.05	0.0001	Significant.

Source: AmerenUE Critical Peak Pricing Pilot, page 10.

[106] Voytas, R., "AmerenUE Critical Peak Pricing Pilot," presented at Demand Response Resource Center Conference, 2006.

Table A-17
Average Participant Use by Program and Pricing Time - 2005

Program	Jun 1- Aug 31 Period	Control Group (kWh)	Treatment Group (kWh)	Difference	t-test	Pr> |t|	Statistical Significance of the Difference
TOU-CPP	Off Peak	4495	4450	45	0.28	0.78	Not Significant.
TOU-CPP	Mid Peak	2054	2019	35	0.54	0.59	Not Significant.
TOU-CPP	On Peak	927	896	31	0.96	0.34	Not Significant.
TOU-CPP	CPP	252	219	33	3.92	0.00	Significant.
TOU-CPP-Tech	Off Peak	4147	4017	130	0.91	0.37	Not Significant.
TOU-CPP-Tech	Mid Peak	1934	1901	33	0.46	0.65	Not Significant.
TOU-CPP-Tech	On Peak	884	863	21	0.64	0.52	Not Significant.
TOU-CPP-Tech	CPP	240	182	58	5.99	0.00	Significant.

Source: AmerenUE Critical Peak Pricing Pilot, page 11.

The results from Table A-16 and A-17 show that:

- In 2005, the TOU-CPP rate induced customers to reduce usage during CPP periods.
- In 2005, the TOU-CPP-Tech rate induced customers to reduce usage during CPP periods.

New Jersey—GPU Pilot[107]

GPU offered a residential TOU pilot program with a critical peak price and enabling technology component in the summer of 1997. Rate design involved three price tiers (peak, shoulder, and off-peak) and a critical peak price that is only effective for a limited number of high-cost summer hours. Moreover, the pilot program tested the impacts from two sets of alternative rates by allocating treatment customers to two groups and subjecting each group to one of the two sets. Table A-18 shows the control and treatment group rate designs.

One important feature of this pilot is that the treatment customers were installed communication equipments that allowed them to preset their usage patterns in response to the time-varying rates and receive price signals from the utility during the critical hours.

[107] Braithwait, S. 2000. Residential TOU Price Response in the Presence of Interactive Communication Equipment. In Pricing in Competitive Electricity Markets, edited by K. E. Ahmad Faruqui: Springer.

Table A-18
Experiment Rate Design of New Jersey GPU Pilot

Group	Charge	Applicable
Control	Standard increasing-block residential tariff: $0.12/kWh if consumption <=600kWh per month $0.153/kWh if consumption >600kWh per month	All Hours
Treatment Group 1 (High shoulder/peak design)	Off-peak: $0.065/kWh	1a.m.-8a.m. and 9p.m.-12p.m. weekdays, all day on weekends and holidays.
	Shoulder:$0.175/kWh	9a.m.-2p.m. and 7p.m.-8p.m. weekdays.
	Peak:$0.30/kWh	3p.m.-6p.m. weekdays
	Critical:$0.50/kWh	when called during peak period
Treatment Group 2 (Low shoulder/peak design)	Off-peak:$0.09/kWh	1a.m.-8a.m. and 9p.m.-12p.m. weekdays, all day on weekends and holidays.
	Shoulder:$0.125/kWh	9a.m.-2p.m. and 7p.m.-8p.m. weekdays.
	Peak:$0.25/kWh	3p.m.-6p.m. weekdays
	Critical:$0.50/kWh	when called during peak period

Source: Residential TOU Price Response in the Presence of Interactive Communication Equipment, page 361.

Analysis of the hourly load data for each of the treatment and control group customers collected for the period of June through September 1997 reveal the following results:

- On non-critical weekdays, the largest usage reductions in the average hourly load were observed during the peak period and average to 0.53 KW or 26% relative to the control group. Limited load reductions were also observed during the late-morning shoulder period. The treatment group with the high rate design reduced usage by roughly 50% more during each of peak and shoulder periods compared to the treatment group with the low-rate design.
- On CPP days, the results were similar to those on the non-CPP weekdays, though larger in magnitude, especially during the peak period. In the 1st hour of the peak period, average load reduction was 1.24 KW or 50% reduction compared to the control group. During the next two peak hours, the reduction was around 1 KW, later falling to 0.59 KW on the last peak hour. Also, the treatment group usage was substantially larger than the control group during the shoulder and off-peak periods following the critical peak hours.
- On weekends, average usage is similar for the control and treatment customers, with slightly lower (though not statistically significant) levels for the treatment customers.
- Average usage over all days by the treatment group decreased by roughly 5% (though not statistically significant) compared to the control group and a large portion of these reductions can be attributed to the changes in the weekday usage. Average daily usage on weekend, weekdays, and all days are presented in Table A-19.

Table A-19
Average Daily Usage for Summer 1997 (kWh)

	Control	Treatment	Usage Difference	Percent Difference
Weekdays	30.4	28.3	-2.1	-6.9%
Weekends	34.1	33.7	-0.4	-1.2%
All days	32.5	30.9	-1.6	-4.9%

Source: Residential TOU Price Response in the Presence of Interactive Communication Equipment, pg 366.

Pilot results were also used to estimate substitution elasticities. Elasticity estimates are based on two alternative demand models; the constant elasticity of substitution (CES) model and the generalized Leontief (GL) model.

- Substitution elasticity from the CES model is estimated to be -0.30 and shows the percentage change in usage ratio due the change in price ratio between any two TOU-price periods. This estimate is larger than -0.17, the average of previous estimates from several other studies. Larger substitution elasticities from this pilot can be attributed to the presence of interactive communication equipments through which the customers preset their usage patterns of AC and some other appliance.
- GL model allows substitution elasticity estimates vary by the time-period. Substitution elasticity between peak and off-peak periods is estimated as -0.40 from the GL model. Substitution elasticities between other time-periods are shown in Table A-20.

Table A-20
Elasticities of Substitution

			GL	
Month	**Time Period**	**CES**	**High Rate Tariff**	**Low Rate Tariff**
1	Overall	-0.306		
	Peak-shoulder		-0.155	-0.166
	Peak-off-peak		-0.395	-0.356
	Shoulder-off-peak		-0.191	-0.187
2	Overall	-0.295		
	Peak-shoulder		-0.055	-0.06
	Peak-off-peak		-0.407	-0.366
	Shoulder-off-peak		-0.178	-0.176

Source: Residential TOU Price Response in the Presence of Interactive Communication Equipment, pg 371.

New Jersey—PSE&G Residential Pilot Program [108]

Public Service Electric and Gas Company (PSE&G) offered a residential TOU/CPP pilot pricing program in New Jersey during 2006 and 2007. The PSE&G pilot had two sub-programs. Under the first sub-program, *myPower Sense*, participants were educated about the TOU/CPP tariff and were notified of the CPP event on a day-ahead basis and the program assessed the reduction in energy use when a CPP event was called. Under the second sub-program *myPower Connection*, also designed to assess the reduction in energy use when a CPP event was called, participants were given a free thermostat that received price signals from PSE&G and adjusted their central air conditioner based on previously programmed set points.

A total of 1,286 customers participated in the pilot program; 450 in the control group, 459 in *myPower Sense*, and 377 in *myPower Connection*. PSE&G recruited the participants separately for each group through direct mail and telemarketing. Participants were not given the opportunity to choose the treatment they would receive. *myPower Sense* customers received a $25 incentive upon enrollment and another $75 to be paid upon the conclusion of the program. *myPower Connection* participants were given free programmable thermostats and received $75 at the end of the program.

The TOU/CPP tariff included an off-peak rate, a base rate, an on-peak rate, and a critical peak rate for the summer months as shown in Table A-21.

Table A-21
PSE&G TOU/CPP Rate Design: Summer Months (June to September 2006)

Period	Charge	Applicable
Base Price	$0.09/kWh	All hours
Night Discount	-$0.05/kWh	10 p.m.-9 a.m. daily
On Peak Adder	$0.08/kWh	1 p.m.-6 p.m. weekdays
Critical Peak Adder	$0.69/kWh	1 p.m.-6 p.m. weekdays when called (added to the base price when called.)

Source: PSEG-CPP Plot, page 3.

[108] PSE&G and Summit Blue Consulting, "Residential Time-of-Use with Critical Peak Pricing Pilot Program: Comparing Customer Response between Educate-Only and Technology Assisted Pilot Segments," 2007.

TOU/CPP program impacts are summarized in Tables A-22 and A-23. The results show that a 100% increase in the peak to off-peak price ratio leads to an 8.5% decrease in the peak to off-peak demand ratio for *myPower Sense* customers (i.e., a substitution elasticity of 0.085). Similarly, *myPower Connection* customers reduced their peak to off-peak consumption ratio by 13.7% percent when the peak to off-peak price ratio increased by 100%. During a non-CPP day, a customer with an initial peak demand of 3.5 kWh experienced a 0.40 kWh (12%) reduction in *myPower Sense* segment and a 0.63 kWh (18%) reduction in *myPower Connection*. The results also show reductions of 1.1 and 2.1 kW per hour during CPP events for *myPower Sense* and *myPower Connection*, respectively.

The higher reductions for *myPower Connection* customers are not surprising since these customers had an enabling technology (i.e., the smart thermostat) whereas the myPower Sense customers did not.

Table A-22
Estimated Substitution Elasticity

Impact Estimate	Coefficient	90% Confidence Interval
myPower Sense	-0.085	-0.079 to -0.090
myPower Connection	-0.137	-0.131 to -0.142

Source: PSEG-CPP Pilot, page 4.

Table A-23
Estimated CPP Event Impacts (average kW per hour)

Impact Estimate	Coefficient	90% Confidence Interval
myPower Sense	1.11	0.133 to 2.08
myPower Connection	2.12	1.09 to 3.17

Source: PSEG-CPP Pilot, page 4.

New South Wales/Australia—Energy Australia's Network Tariff Reform [109]

The Time of Use (TOU) pricing program is the largest demand management project by Energy Australia. Recent price elasticity estimates from the TOU tariffs are presented in Table A-24.

Table A-24
Australia NSW—TOU Price Elasticity Estimates

Type	Season	Peak Own Price Elasticity	Peak to Shoulder Cross Price Elasticity	Peak to Off-Peak Cross Price Elasticity
Residential	Summer 2006	-030 to -0.38	-0.07	-0.04
	Winter 2006	-0.47	-0.12	#N/A
Business (less than 40 MWh)	Summer 2006	-0.16 to -0.18 (ns)	-0.03	#N/A
	Winter 2006	-0.2 (ns)	#N/A	#N/A
Business (40 MWh to 160 MWh)	Summer 2006	-0.03 to -0.13 (ns)	#N/A	#N/A
	Winter 2006	-0.02 to -0.09 (ns)	#N/A	#N/A

Source: Network Price Reform , page 10.
Notes: ns refers to "not statistically significant".

The TOU results show that:

- Slight energy conservation effects result from residential consumption under TOU rates (compared to residential consumption under the flat tariffs).
- Conservation effects are larger in winter than in summer for the residential customers.
- Business customer elasticities are not statistically significant due to large estimation errors stemming from heterogeneity. Therefore, they should be interpreted with caution.

Energy Australia started the Strategic Pricing Study in 2005, which included 1,300 voluntary customers (50% business, 50% resident). The study tested seasonal, dynamic, and information only tariffs and involved the use of in-house displays and online access to data. Study participants received dynamic price signals through Short Message Service (SMS), telephone, email, or the display unit.

Preliminary results that are available from three Dynamic Peak Pricing (DPP) events show that:

- Residential customers reduced their dynamic peak consumption by roughly 24% for DPP high rates ($2+/kWh) and roughly 20% for DPP medium rates ($1+/kWh).
- Response to the 2nd DPP event was greater than that to the 1st DPP event. This may be attributed to the day-ahead notification under the 2nd DPP event (versus day-of notification under the 1st DPP event) and/or temperature differences.
- Response to the 2nd event was also greater than to the 3rd DPP event. This may be explained by lower temperatures on the 3rd DPP event which may have led to less discretionary appliances to turn off.

[109] Harry Colebourn, "Network Price Reform," presented at BCSE Energy Infrastructure& Sustainability Conference, December 2006.

Ontario/Canada—Ontario Energy Board Smart Price Pilot[110]

The Ontario Energy Board operated the residential Ontario Energy Board Smart Price Pilot (OSPP) between August 2006 and March 2007. The OSPP used a sample of Hydro Ottawa residential customers and tested the impacts from three different price structures:

- The existing Regulated Price Plan (RPP) TOU—rates are shown in Table A-25.
- RPP TOU rates with a CPP component (TOU CPP). The CPP was set at $0.30 per kWh based on the average of the 93 highest hourly Ontario electricity prices in the previous year. The RPP TOU off-peak price was decreased to $0.031 (from $0.035) per kWh to offset the increase in the critical peak price. The maximum number of critical day events was set at 9 days, however only 7 CPP days were called during the pilot.
- RPP TOU rates with a critical peak rebate (TOU CPR): The CPR provided participants with a $0.30 per kWh rebate for each kWh of reduction from estimated baseline consumption. The CPR baseline consumption was defined as the average usage during the same hours over the participants' last five non-event weekdays, increased by 25%.

Table A-25
Regulated Price Plan (RPP) TOU Rate Design

Season	Time	Charge	Applicable
Summer (Aug 1- Oct 31)	Off-peak	$0.035/kWh	10 p.m.- 7 a.m. weekdays, all day on weekends and holidays.
Summer (Aug 1- Oct 31)	Mid-peak	$0.075/kWh	7 a.m.- 11 a.m. and 5 p.m.- 10 p.m. weekdays.
Summer (Aug 1- Oct 31)	On-peak	$0.105/kWh	11 a.m.- 5 p.m. weekdays.

Source: Ontario Energy Board Smart Price Pilot, page 2.

A total of 373 customers participated in the pilot: 124 in TOU-only, 124 in TOU-CPP, and 125 in TOU-CPR. The control group included 125 participants who had smart meters installed but continued to pay non-TOU rates.

The OSPP results show that:

- The load shift during the critical hours of the four summer CPP events ranged between 5.7 % and 25.4 %. [111]
- The load shift during the entire peak period of the four summer CPP events ranged between 2.4% and 11.9%.

Table A-26 shows the shift in load during a CPP event as a percentage of the load in critical peak hours and of the entire peak period. It is important to note that the percentage reductions for the TOU-only customers are not significant at the 90% confidence level.

[110] Ontario Energy Board, "Ontario Energy Board Smart Price Pilot Final Report," 2007.
[111] Under the OSPP, 3 to 4 hours of the peak period were defined as critical on a CPP day.

Table A-26
OSPP: Percentage Load Shifts under Different RPP Structures (Four Summer CPP Events)

Period	TOU- only	TOU- CPP	TOU- CPR
Shift as % of critical peak hours	5.7%	25.4%	17.5%
Shift as % of all peak hours	2.4%	11.9%	8.5%

Source: Ontario Energy Board Smart Price Pilot, page 5.

This study also analyzed the total conservation impact during the full pilot period. The total reduction in electricity consumption due to program impacts is reported in Table A-27. The average conservation impact across all customers was 6%.

Table A-27
Total Conservation Effect for Full Pilot Duration (Treatment vs. Control Group)

Program	% Reduction in Total Electricity Usage
TOU-only	6.0%
TOU- CPP	4.7% (ns)
TOU- CPR	7.4%
Average Impact	6.0%

Source: Ontario Energy Board Smart Price Pilot, page 5.
Note: ns refers to "not significant at the 90 % confidence level".

Seattle—Puget Sound Energy (PSE) TOU Program[112]

Puget Sound Energy (PSE) initiated a time-of-use (TOU) program for its residential and small commercial customers in the 2001 to 2003 time period, in conjunction with a smart meter roll-out. The rate design featured four price tiers; prices were most expensive during the morning and evening periods, with mid-day and economy periods following these most expensive periods. 300,000 PSE customers were placed in the program and given the option to go back to the standard rates if they were not satisfied with the program. Peak price was roughly 15% higher than the average prevailing price before the program, and the off-peak price was 15% lower. In the second year of the program, customers were charged a monthly fee of $1 per month for meter reading costs.

[112] Faruqui, A., S. George. 2003. "Demise of PSE's TOU Program Imparts Lessons." Electric Light & Power. Vol. 81.01:14-15.

The results of PSE's quarterly report revealed that 94 percent of the TOU program participants paid a *net $0.80 extra per month by participating in the pilot*; an average bill savings of $0.20 against an incremental $1 meter reading charge. This was in contrast with the 1st year results where customers were not charged meter reading costs and around 55% of them experienced bill savings. As the result of customer dissatisfaction and negative media coverage, PSE ceased its TOU program. Following are several lessons that were derived from this experience:

- Modest price differentials between peak and off-peak may induce customers to shift their load. An independent analysis of the program found that the customers lowered peak usage by 5 % per month over a 15 month period.
- It is important to provide customers with accurate expectations about their bill savings.
- It is essential to offer a pilot program before implementing a full-scale program.

Washington & Oregon—Olympic Peninsula Project[113]

The Olympic Peninsula Project was a component of the Pacific Northwest GridWise Testbed Demonstration that took place in Washington and Oregon and led by the Pacific Northwest National Laboratory (PNNL). It tested whether automated two-way communication systems between grid and passive resources (i.e. end use loads and idle distributed generation) and the use of price signals as instruments would be effective in reducing the stress on the system. This review will focus on the residential response and will not cover the impacts associated with the distributed generation resources.

By the end of 2005, 112 residential homes were installed the two-way communication equipments that allowed utilities to send the market price signals to the consumers and allowed consumers to pre-program their demand response preferences. These 112 residential participants were then evenly divided into three treatment groups and a control group. Control group homes were also installed the equipments, but these customers had no program accounts, contacts, or bills. Each treatment group was assigned to one of the three electricity contracts:

- Fixed Price program contract: constant prices at all times.
- Time-of-use/critical peak price (TOU/CPP) program contract: prices differ between peak and off-peak time periods, with peak price much higher during critical peak days.
- Real Time contract: unpredictable prices subject to variation every five minutes. Participants of this contract could respond to real time prices by pre-setting their preferences through the web, but retained the option to override their preferences at any time.

Table A-28 shows the prices that prevail under fixed price and TOU/CPP contracts.

[113] Pacific Northwest National Laboratory. "Pacific Northwest GridWise Testbed Demonstration Projects Part 1: Olympic Peninsula Project". 2007

Table A-28
Olympic Peninsula Project, Experiment Rate Design

Contract	Season	Period	Charge	Applicable
Time-of-Use	Spring (1 Apr-24 Jul) and Fall/Winter (1 Oct-31 Mar)	Off-peak	$0.04119/kWh	9 am-6pm and 9pm-6am
		On-peak	$0.1215/kWh	6am-9am and 6pm-9pm
		Critical	$0.35/kWh	not called
	Summer (25 Jul- 30 Sep)	Off-peak	$0.05/kWh	9am-3pm
		On-peak	$0.135/kWh	3pm-9pm
		Critical	$0.35/kWh	when called
Fixed-Price	All seasons	All day	$0.081/kWh	All hours

Source: Pacific Northwest GridWise Testbed Demonstration Projects: Part 1. Olympic Peninsula Project, pg 3.5

Results from the pilot for the residential participants are as follows:

- The Fixed Price group saved 2% in their average monthly bill compared to the control group; TOU group saved 30%, and Real Time group saved 27%.
- Differences in average energy consumption between the contract groups were small but statistically significant. The TOU group consumed 21% less energy, thereby demonstrating a conservation effect. By contrast, the Real Time group consumed as much as the control group, while the Fixed Price group consumed 4% more energy than the control group. The usage comparison across the contract groups is presented in Table A-29.

Table A-29
Average Daily Energy Consumption per Home (April – December 2006)

Contract Type	Average Daily Energy Consumption (kWh)	Standard Deviation(kWh)	Percentage Difference (compared to the Control)
Control	47	24	0%
Fixed	49	22	4%
Time-of-Use	39	29	-21%
Real-Time	47	26	0%

Source: Pacific Northwest GridWise Testbed Demonstration Projects: Part 1. Olympic Peninsula Project, pg 7.7

- Examination of the residential load shapes by contract and season reveals that the TOU contract was the most effective design at reducing the peak-demand.
- Real-time group exhibited the smoothest load response, explained by the fact that the real-time pricing induces a response when it is most needed during a relatively small portion of all hours. Therefore, it is not surprising to see that, on average, the Real-Time contract does not result in the lowest average peak demand. Nevertheless, Real-Time price control was effective at reducing congestion peaks.

Residential Customer Response in Early Time-of-Use Pricing Experiments

To provide historical context to these fourteen recent residential dynamic pricing pilots and programs, we reviewed two studies that provide conclusions from numerous early generation Time-of-Use (TOU) rate pilot programs.

A paper by Caves et. al. in 1984 compiles data from five residential TOU experiments conducted by Carolina Power and Light, Connecticut Light and Power, Los Angeles Department of Water and Power, Southern California Edison, and Wisconsin Public Service.[114] The paper estimates a consumer demand model for each of these experiments to test the hypothesis that the substitution elasticities are identical across experiments. Results of the study provide support for this hypothesis, and therefore provide a general model for estimating the residential response to TOU pricing. Since all five experiments used in this study featured some form of mandatory participation, results can not be generalized to voluntary TOU settings. Selected findings from the study are the following:

- The price differential between peak and off-peak usage is the primary factor that determines the degree of customer response.
- The roles played by appliance holdings (the stock of energy-consuming equipment available in the customer's home), customer characteristics, and climate are discernible, but they do not affect the magnitude of customer response nearly as much as the price differential.
- The elasticity of substitution varies with appliance holdings, customer characteristics, and climate but, after controlling for these factors, it does not vary across areas.
- The elasticity of substitution between weekdays and weekends is smaller than that between peak and off-peak periods on weekdays.
- The results show that TOU rates lead to a reduction in the overall electricity usage.
- Estimation of the results for the system peak days revealed no different response on these days compared to an average weekday.
- The typical customer in the typical climate has a substitution elasticity of -0.14. It is important to note that this elasticity estimate is higher than the values estimated from the second generation of pilots. Substitution elasticity estimates for different customer characteristics and climate zones are shown in Table A-30.

[114] Caves, D. W., L. R. Christensen, and J. A. Herriges. 1984. "Consistency of Residential Customer Response in Time-of-Use Electricity Pricing Experiments." Journal of Econometrics 26:179-203.

Table A-30
Elasticity of Substitution Estimates for Summer Months (Peak to Off-Peak Usage)

Type of Climate	No Appliances	Typical Appliances	All Appliances	Typical Appliances except No AC Ownership	Typical Appliances except AC Ownership
Cool	0.09	0.12	0.16	0.13	0.11
Typical	0.07	0.14	0.21	0.11	0.16
Hot	0.05	0.15	0.25	0.1	0.21

Source: Consistency of Residential Customer Response in Time-of-Use Electricity Pricing Experiments, page 198.

A second study, conducted in 1983 by Faruqui and Malko, reviews the empirical evidence from 12 of 15 residential pricing experiments that were funded and managed by DOE during late 1970s.[115] Based on the review of the pricing experiments:

- TOU pricing generally reduces peak energy consumption. Off-peak consumption stays the same or rises slightly.
- TOU pricing generally reduces daily energy consumption. Explicit load shifting from peak to off-peak is rarely observed.
- Customer response on average weekdays and system peak days differs only slightly.
- High usage customers are more responsive to TOU rates than are low usage customers.
- Peak and off-peak own-price elasticities range from 0 to -0.4. In a given experiment, elasticities vary across customers due to variation in total usage, appliance portfolio, and other factors. Across the experiments, these elasticities vary due to rate differences, variation in climate conditions, etc.
- There is little difference between elasticity estimates derived from single equations or demand systems.

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