Executive Summary

This report on Aligning Utility Incentives with Investment in Energy Efficiency describes the financial effects on a utility of its spending on energy efficiency programs, how those effects could constitute barriers to more aggressive and sustained utility investment in energy efficiency, and how adoption of various policy mechanisms can reduce or eliminate these barriers. The Report also provides a number of examples of such mechanisms drawn from the experience of utilities and states. The Report is provided to assist in the implementation of the National Action Plan for Energy Efficiency's five key policy recommendations for creating a sustainable, aggressive national commitment to energy efficiency.

Improving energy efficiency in our homes, businesses, schools, governments, and industries—which collectively consume more than 70 percent of the natural gas and electricity used in the country—is one of the most constructive, cost-effective ways to address the challenges of high energy prices, energy security and independence, air pollution, and global climate change. Despite these benefits and the success of energy efficiency programs in some regions of the country, energy efficiency remains critically underutilized in the nation's energy portfolio. It is time to take advantage of more than two decades of experience with successful energy efficiency programs, broaden and expand these efforts, and capture the savings that energy efficiency offers. Aligning the financial incentives of utilities with the delivery of cost-effective energy efficiency supports the key role utilities can play in capturing energy savings.

This Report has been developed to help parties fully implement the five key policy recommendations of the National Action Plan for Energy Efficiency. (See page 1-2 for a full list of options to consider under each Action Plan recommendation.) The Action Plan was released in July 2006 as a call to action to bring diverse stakeholders together at the national, regional, state, or utility level, as appropriate, and foster the discussions, decision-making, and commitments necessary to take investment in energy efficiency to a new level.

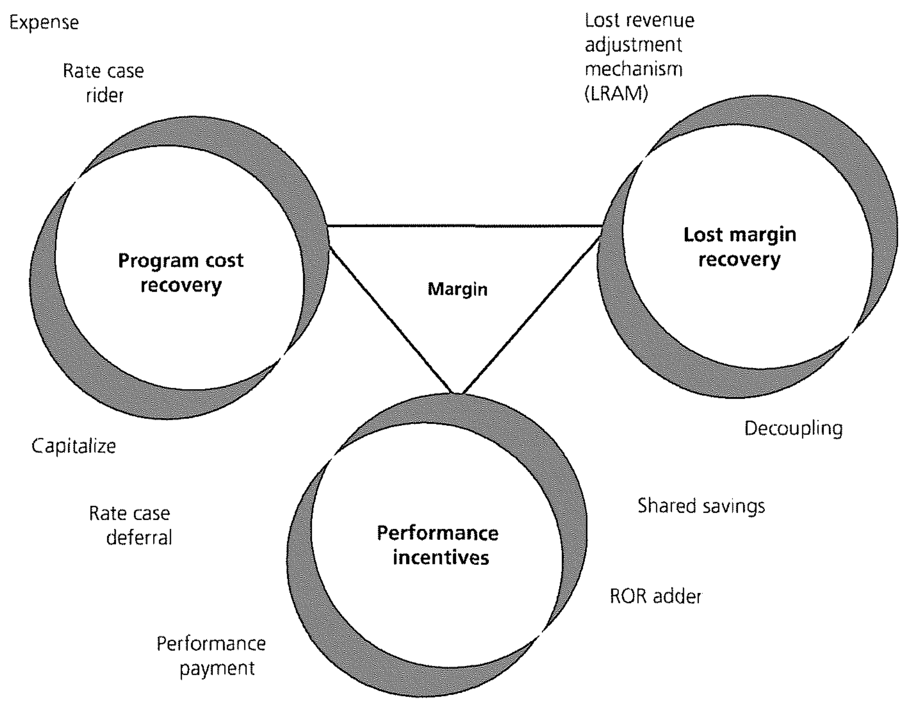
This Report directly supports the Action Plan recommendations to "provide sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective" and "modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments." Key options to consider under this recommendation include committing to a consistent way to recover costs in a timely manner, addressing the typical utility throughput incentive and providing utility incentives for the successful management of energy efficiency programs.

There are a number of possible regulatory mechanisms for addressing these issues. Determining which mechanism will work best for any given jurisdiction is a process that takes into account the type and financial structure of the utilities in that jurisdiction; existing statutory and regulatory authority; and the size of the energy efficiency investment. The net impact of an energy efficiency cost recovery and performance incentives policy will be affected by a wide variety of other rate design, cost recovery, and resource procurement strategies, as well as broader considerations, such as the rate of demand growth and environmental and resource policies.

The Financial and Policy Context

Utility spending on energy efficiency programs can affect the utility's financial position in three ways: (1) through recovery of the direct costs of the programs; (2) through the impact on utility earnings of reduced sales; and (3) through the effects on shareholder value of energy efficiency spending versus investment in supply-side resources. The relative importance of each effect to a utility is measured by its impact on earnings. A variety of mechanisms have been developed to address these impacts, as illustrated in Figure ES-1.

Figure ES-1. Program cost recovery and performance incentive options.



How these impacts are addressed creates the incentives and disincentives for utilities to pursue energy efficiency investment. The relative importance of each of these depends on specific context—the impacts of energy efficiency programs will look different to gas and electric utilities, and to investor-owned, publicly owned, and cooperatively owned utilities.

Comprehensive policies addressing all three levels of impact generally are considered more effective in spurring utilities to pursue efficiency aggressively. Ultimately, however, it is the cumulative net effect on utility earnings or net income of a policy that will determine the alignment of utility financial interests with energy efficiency investment. The same effect can be achieved in different ways, not all of which will include explicit mechanisms for each level. Chapter 2 of this Report explores the financial effects of and policy issues associated with utility energy efficiency spending.

Program Cost Recovery

The most immediate impact is that of the direct costs associated with program administration (including evaluation), implementation, and incentives to program participants. Reasonable opportunity for program cost recovery is a necessary condition for utility program spending, as failure to recover these costs produces a direct dollar-for-dollar reduction in utility earnings, all else being equal, and sends a discouraging message regarding further investment.

Policy-makers have a wide variety of tools available to them within the broad categories of expensing and capitalization to address cost recovery. Program costs can be recovered as expenses or can be treated like capital items by accruing program costs with carrying charges, and then amortizing the balances with recovery over a period of years. Chapter 4 reviews both general options as well as several approaches for the tracking, accrual, and recovery of program costs. Case studies for Arizona, Iowa, Florida, and Nevada are presented to illustrate the actual application of the mechanisms.

Each of these tools can have different financial impacts, but the key factors in any case are the determination of the prudence of program expenditures and the timing of cost recovery. How each of these is addressed will affect the perceived financial risk of the policy. The more uncertain the process for determining the prudence of expenditures, and the longer the time between an expenditure and its recovery, the greater the perceived financial risk and the less likely a utility will be to aggressively pursue energy efficiency.

Lost Margin Recovery and the Throughput Incentive

The second impact, sometimes called the *lost margin recovery* issue is the effect on utility financial margins caused by the energy efficiency-produced drop in sales. Utilities incur both fixed and variable costs. Fixed costs include a return ***of*** (depreciation) and a return ***on*** (interest plus earnings) capital (a utility's physical infrastructure), as well as property taxes and certain operation and maintenance (O&M) costs. These costs do not vary as a function of sales in the short-run. However, most utility rate designs attempt to recover a portion of these fixed costs through volumetric prices—a price per kilowatt-hour or per therm. These prices are based on an estimate of sales: *price = revenue requirement/sales*.[1] If actual sales are either higher or lower than the level estimated when prices are set, revenues will be higher or lower. All else being equal, if an energy efficiency program reduces sales, it reduces revenues proportionately, but fixed costs do not change. Less revenue, therefore, means that the utility is at some risk for not recovering all of its fixed costs. Ultimately, the drop in revenue will impact the utility's earnings for an investor-owned utility, or net operating margin for publicly and cooperatively owned utilities.

Few energy efficiency policy issues have generated as much debate as the issue of the impact of energy efficiency programs on utility margins. Arguments on all sides of the lost margin issue can be compelling. Many observers would agree that significant and sustained investment in energy efficiency by utilities, beyond that required under statute or order, will not occur without implementation of some type of mechanism to ensure recovery of lost margins. Others argue that the lost margin issue cannot be treated in isolation; margin recovery is affected by a wide variety of factors, and special adjustments for energy efficiency constitute single issue ratemaking.[2]

Care should be taken to ensure that two very different issues are not incorrectly treated as one. The first issue is whether a utility should be compensated for the under-recovery of fixed costs when energy efficiency programs or events outside of the control of the utility (e.g., weather or a drop in economic activity) reduce sales below the level on which current rates are based. *Lost revenue adjustment mechanisms* (LRAMs) have been designed to estimate and collect the margin revenues that might be lost due to a successful energy efficiency program. These mechanisms compensate utilities for the effect of reduced sales due to efficiency, but they do not change the linkage between sales and profit. Few states currently use these mechanisms.

The second issue is whether potential lost margins should be addressed as a stand-alone matter of cost recovery or by *decoupling* revenues from sales—an approach that fundamentally changes the relationship between sales and revenues, and thus margins. Decoupling not only addresses lost margin recovery, but also removes the *throughput incentive*—the incentive for utilities to promote sales growth, which is created when fixed costs are recovered through volumetric charges. The throughput incentive has been identified by many as the primary barrier to aggressive utility investment in energy efficiency.

Chapter 5 examines the cause of and options for recovery of lost margins, and case studies are presented for decoupling in Idaho, New Jersey, Maryland, and Utah, and for the application of a LRAM in Kentucky.

Utility Performance Incentives

The two impacts described above pertain to potential direct disincentives for utilities to engage in energy efficiency program investment. The third impact concerns incentives for utilities to undertake such investment. Under traditional regulation, investor-owned utilities earn returns on capital invested in generation, transmission, and distribution. Unless given the opportunity to profit from the energy efficiency investment that is intended to substitute for this capital investment, there is a clear financial incentive to prefer investment in supply-side assets, since these investments contribute to enhanced shareholder value. Providing financial incentives to a utility if it performs well in delivering energy efficiency can change that business model by making efficiency profitable rather than merely a break-even activity.

The three major types of performance mechanisms have been most prevalent include:

- Performance target incentives.
- Shared savings incentives.
- Rate of return adders.

Performance target incentives provide payment—often a percentage of the total program budget—for achievement of specific metrics, usually including savings targets. Most states providing such incentives set performance ranges; incentives are not paid unless a utility achieves some minimum fraction of proposed savings, and incentives are capped at some level above projected savings.

Shared savings mechanisms provide utilities the opportunity to share with ratepayers the net benefits resulting from successful implementation of energy efficiency programs. These structures also include specific performance targets that tie the percentage of net savings awarded to the percentage of goal achieved. Some, but not all shared savings mechanisms include penalty provisions requiring utilities to pay customers when minimum performance targets are not achieved.

Rate of return adders provide an increase in the return on equity (ROE) applied to capitalized energy efficiency expenditures. This approach currently is not common as a performance incentive for several reasons. First, this mechanism requires energy efficiency program costs to be capitalized, which relatively few utilities prefer. Second, at least as applied in several cases, the adder is not tied to performance—it simply is applied to all capitalized energy efficiency costs as a way to broadly incent a utility for efficiency spending. On the other hand, capitalization, in theory, places energy efficiency on more equal financial terms with supply-side investments to begin with. Thus, any adder could be viewed more as a risk-premium for investment in a regulatory asset.

The premise that utilities should be paid incentives as a condition for effective delivery of energy efficiency programs is not universally accepted. Some argue that utilities are obligated to pursue energy efficiency if that is the policy of a state, and that performance incentives require customers to pay utilities to do something that they should do anyway. Others have argued more directly that the basic business of a utility is to deliver energy, and that providing financial incentives over-and-above what could be earned by efficient management of the supply business simply raises the cost of service to all customers and distorts management behavior.

Chapter 6 reviews these mechanisms in greater detail and provides case studies drawn from Massachusetts, Minnesota, Hawaii, and California.

Table ES-1 summarizes the current level of state activity with regard to the financial mechanisms described above.

Table ES-1. The Status of Energy Efficiency Cost Recovery and Incentive Mechanisms for Investor-Owned Utilities

State	Direct Cost Recovery			Fixed Cost Recovery		Performance Incentives
	Rate Case	SBC	Tariff Rider/ Surcharge	Decoupling	Lost Revenue Adjustment Mechanism	
Alabama	Yes					
Alaska						
Arizona	Yes (electric)	Yes (electric)		Pending (gas)		Yes (electric)
Arkansas				Yes (gas)		
California	Yes	Yes		Yes		Yes
Colorado	Yes		Yes	Pending		Yes
Connecticut		Yes (electric)			Yes	Yes
Delaware	Yes			Pending		
District of Columbia	Yes			Pending (electric)		
Florida			Yes (electric)			
Georgia	Yes					Yes (electric)
Hawaii				Pending (electric)		Yes
Idaho	Yes (electric)			Yes (electric)		
Illinois	Yes (electric)					
Indiana	Yes			Yes (gas)	Yes	Yes
Iowa	Yes		Yes			
Kansas						Yes
Kentucky			Yes	Pending (gas)	Yes	Yes
Louisiana						
Maine		Yes (electric)				

State	Direct Cost Recovery			Fixed Cost Recovery		
	Rate Case	SBC	Tariff Rider/ Surcharge	Decoupling	Lost Revenue Adjustment Mechanism	Performance Incentives
Maryland				Yes (gas) Pending (electric)		
Massachusetts		Yes (electric)		Pending (electric)	Yes	Yes (electric)
Michigan				Pending (gas)		
Minnesota	Yes			Yes		Yes
Mississippi	Yes					
Missouri				Yes (gas)		
Montana	Yes (gas)	Yes (electric)				Yes
Nebraska						
Nevada	Yes (electric)			Yes (gas)		Yes (electric)
New Hampshire		Yes (electric)		Pending (electric)		Yes (electric)
New Jersey		Yes		Yes (gas) Pending (electric)		
New Mexico	Yes			Pending (gas)		
New York		Yes (electric)		Yes		
North Carolina				Yes (gas)		
North Dakota						
Ohio			Yes (electric)	Yes (gas)	Yes (electric)	Yes (electric)
Oklahoma						
Oregon		Yes		Yes (gas)		
Pennsylvania	Yes					
Rhode Island		Yes (electric)		Yes		Yes
South Carolina						Yes
South Dakota						
Tennessee						
Texas	Yes					

State	Direct Cost Recovery			Fixed Cost Recovery		Performance Incentives
	Rate Case	SBC	Tariff Rider/ Surcharge	Decoupling	Lost Revenue Adjustment Mechanism	
Utah	Yes (electric)		Yes (electric)	Yes (gas)		
Vermont		Yes (electric)			Yes	Yes
Virginia				Pending (gas)		
Washington	Yes (electric)		Yes (electric)	Yes (gas)		
West Virginia						
Wisconsin	Yes (electric)	Yes (electric)		Pending (electric)		
Wyoming						

Understanding Objectives—Developing Policy Approaches That Fit

The overarching goal in every jurisdiction that considers an energy efficiency investment policy is to generate and capture substantial net economic benefits. Achieving this goal requires aligning utility financial interests with investment in energy efficiency. The right combination of cost recovery and performance incentive mechanisms to support this alignment requires a balancing of a variety of more specific objectives common to the ratemaking process. Chapter 3 reviews how these objectives might influence design of a cost recovery and performance incentive policy, and highlights elements of the policy context that will affect policy design. Each of these objectives are not given equal weight by policy-makers, but most are given at least some consideration in virtually every discussion of cost recovery and performance incentives.

- **Strike an Appropriate Balance of Risk/Reward Between Utilities/Customers.** If a mechanism is well-designed and implemented, customer benefits will be large enough to allow sharing some of this benefit as a way to reduce utility risk and strengthen institutional commitment; all parties will be better off than if no investment had been made.
- **Promote Stabilization of Customer Rates and Bills.** While it is prudent to explore policy designs that, among available options, minimize potential rate volatility, the pursuit of rate stability should be balanced against the broader interest of lowering the overall cost of providing electricity and natural gas.
- **Stabilize Utility Revenues.** Even if cost recovery policy covers program costs, fixed cost recovery and performance incentives, how this recovery takes place can affect the pattern of cash flow and earnings. Large episodic jumps in earnings (produced, for

example, by a decision to allow recovery of accrued under-recovery of fixed costs in a lump sum), can cloud financial analysts' ability to discern the true financial performance of a company.

- **Administrative Simplicity and Managing Regulatory Costs.** Simplicity requires that any/all mechanisms be transparent with respect to both calculation of recoverable amounts and overall impact on utility earnings. Every mechanism will impose some incremental cost on all parties, since some regulatory responsibilities are inevitable. The objective, therefore, is to structure mechanisms that lend themselves to a consistent and more formulaic process. This objective can be satisfied by providing clear rules prescribing what is considered acceptable/necessary as part of an investment plan.

Finding the right policy balance hinges on a wide range of factors that can influence how a cost recovery and performance incentive measure will actually work. These factors will include: industry structure (gas or electric utility, public or investor-owned, restructured or bundled); regulatory structure and process (types of test year, current rate design policies); and utility operating environment (demand growth and volatility, utility cost and financial structure, structure of the energy efficiency portfolio). Given the complexity of many of these issues, most states defer to state utility regulators to fashion specific cost recovery and performance incentive mechanism(s).

Emerging Models

Although the details of the policies and mechanisms for addressing the financial impacts of energy efficiency programs continue to evolve in jurisdictions across the country, the basic classes of mechanisms have been understood, applied, and debated for more than two decades. Most jurisdictions currently considering policies to remove financial disincentives to utility investment in energy efficiency are considering one or more of the mechanisms described above. Still, the persistent debate over recovery of lost margins and performance incentives in particular creates an interest in new approaches.

In April 2007, Duke Energy proposed what is arguably the most sweeping alternative to traditional cost recovery, margin recovery and performance incentive approaches since the 1980s. Offered in conjunction with an energy efficiency portfolio in North Carolina, Duke's Energy Efficiency Rider encapsulates program cost recovery, recovery of lost margins, and shareholder incentives into one conceptually simple mechanism tied to the utility's avoided cost. The approach is based on the notion that, if energy efficiency is to be viewed from the utility's perspective as equivalent to a supply resource, the utility should be compensated for its investment in energy efficiency by an amount roughly equal to what it would otherwise spend to build the new capacity that is to be avoided. The Duke proposal would authorize the company, "to recover the amortization of and a return on 90 percent of the costs avoided by producing save-a-watts."

The proposal clearly represents an innovation in thinking regarding elimination of financial disincentives for utilities, and has intuitive appeal for its conceptual simplicity. The Duke proposal does represent a distinct departure from cost recovery and shareholder incentives convention. What is a simple and compelling concept is embedded in a formal mechanism that is quite complex, and the mechanism will likely engender substantial debate.

A second emerging model is represented by the ISO New England's capacity auction process. This process allows demand-side resources to be bid into an auction alongside supply-side resources, and utilities and third-party energy efficiency providers are allowed to participate in the auction with energy efficiency programs. Winning bids receive a revenue stream that could, under certain circumstances, be used to offset direct program costs or lost margins, or could provide a source of performance incentives. The treatment of revenues received from the auction by a utility, however, is subject to allocation by its state utility commission(s), and the traditional approach to the treatment of off-system revenues is to credit them against jurisdictional revenue requirements. Therefore, the capability of this model to address the impacts described above depends largely on state regulatory policy. Whether this model ultimately is transferable to other areas of the country depends greatly on how power markets are structured in these areas.

Final Thoughts

The history of utility energy efficiency investment is rich with examples of how state legislatures, regulatory commissions, and the governing bodies of publicly and cooperatively owned utilities have explored their cost recovery policy options. As these options are reconsidered and reconfigured in light of the trend toward higher utility investment in energy efficiency, this experience yields several lessons with respect to process.

- **Set cost recovery and incentive policy based on the direction of the market's evolution.** The rapid development of technology, the likely integration of energy efficiency and demand response, continuing evolution of utility industry structure, the likelihood of broader action on climate change, and a wide range of other uncertainties argue for cost recovery and incentive policies that can work with intended effect under a variety of possible futures.
- **Apply cost recovery mechanisms and utility performance incentives in a broad policy context.** The policies that affect utility investment in energy efficiency are many and varied and each will control, to some extent, the nature of financial incentives and disincentives that a utility faces. Policies that could impact the design of cost recovery and incentive mechanisms include those having to do with carbon emissions reduction; non-CO_2 environmental control, such as NO_X cap-and-trade initiatives; rate design; resource portfolio standards; and the development of more liquid wholesale markets for load reduction programs.

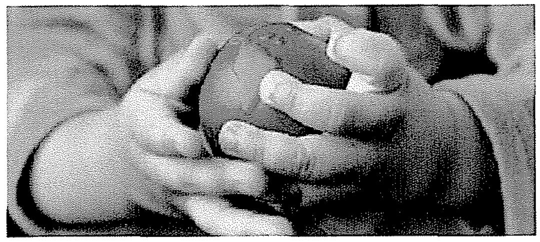
- **Test prospective policies.** Complex mechanisms that have many moving parts cannot easily be understood unless the performance of the mechanisms is simulated under a wide range of conditions. This is particularly true of mechanisms that rely on projections of avoided costs, prices, or program impacts. Simulation of impacts using financial modeling and/or use of targeted pilots can be effective tools to test prospective policies.
- **Policy rules must be clear.** There is a clear link between the risk a utility perceives in recovering its costs, and disincentives to invest in energy efficiency. This risk is mitigated in part by having cost recovery and incentive mechanisms in place, but the efficacy of these mechanisms depends very much on the rules governing their application. While state regulatory commissions often fashion the details of cost recovery, lost margin recovery, and performance incentive mechanisms, the scope of their actions is governed by legislation. In some states, significant expenditures on energy efficiency by utilities are precluded by lack of clarity regarding regulators' authority to address one or more of the financial impacts of these expenditures. Legislation specifically authorizing or requiring various mechanisms creates clarity for parties and minimizes risk.
- **Collaboration has value.** The most successful and sustainable cost recovery and incentive policies are those that are based on a consultative process that, in general, includes broad agreement on the aims of the energy efficiency investment policy.
- **Flexibility is essential.** Most of the states that have had significant efficiency investment and cost recovery policies in place for more than a few years have found compelling reasons to modify these policies at some point. These changes reflect an institutional capacity to acknowledge weaknesses in existing approaches and broader contextual changes that render prior approaches ineffective. Policy stability is desirable, and policy changes that have significant impacts on earnings or prices can be particularly challenging. However, it is the stability of impact rather than adherence to a particular model that is important in addressing financial disincentives to invest.
- **Culture matters.** One important test of a cost recovery and incentives policy is its impact on corporate culture. A policy providing cost recovery is an essential first step in removing financial disincentives associated with energy efficiency investment, but it will not change a utility's core business model. Earnings are still created by investing in supply-side assets and selling more energy. Cost recovery plus a policy enabling recovery of lost margins might make a utility indifferent to selling or saving a kilowatt-hour or therm, but still will not make the business case for aggressive pursuit of energy efficiency. A full complement of cost recovery, lost margin recovery, and performance incentive mechanisms can change this model, and likely will be needed to secure sustainable funding for energy efficiency at levels necessary to fundamentally change resource mix.

Notes

1 Revenue requirement refers to the sum of the costs that a utility is authorized to recover through rates.

2 For example, see the National Association of State Utility Consumer Advocates' Resolution on Energy Conservation and Decoupling, June 12, 2007.

Acknowledgements



This report on Aligning Utility Incentives with Investment in Energy Efficiency is a key product of the Year Two Work Plan for the National Action Plan for Energy Efficiency. This work plan was developed based on feedback received from Action Plan Leadership Group members and observers during fall 2006. The work plan was further refined during the March 2007 Leadership Group meeting in Washington, D.C. A full list of Leadership Group members is provided in Appendix A.

In addition to direction and comment by the Action Plan Leadership Group, this Report was prepared with highly valuable input of an Advisory Group. Val Jensen of ICF International served as project manager and primary author of the Report, with assistance from Basak Uluca, under contract to the U.S. Environmental Protection Agency (EPA).

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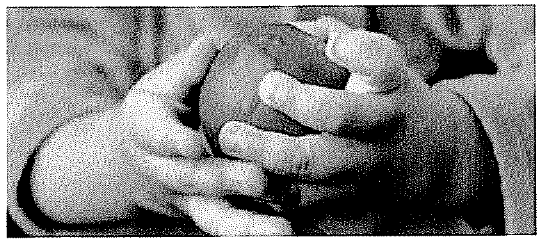

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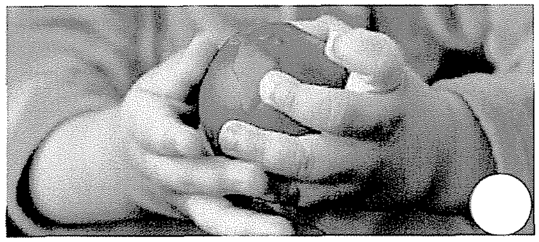
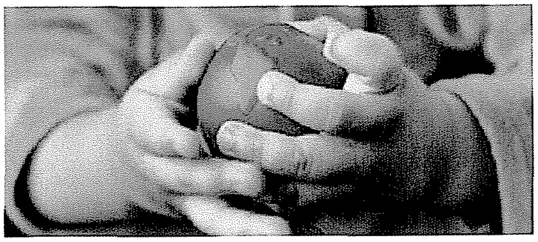


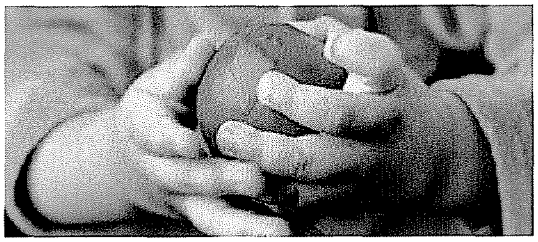
List of Abbreviations and Acronyms



APS	Arizona Public Service Company
BA	balance adjustment
BGE	Baltimore Gas and Electric
BGSS	Basic Gas Supply Service
CCRA	conservation cost recovery adjustment
CCRC	conservation cost recovery charge
CET	conservation enabling tariff
CIP	conservation improvement program or Conservation Incentive Program
CMP	Central Maine Power
CPUC	California Public Utilities Commission
CUA	conservation and usage adjustment
DBA	DSM balance adjustment
DCR	DSM program cost recovery
DNG	distribution non-gas
DOE	U.S. Department of Energy
DRLS	DSM revenue from lost sales
DSM	demand-side management
DSMI	DSM incentive
DSMRC	demand-side management recovery component
ECCR	energy conservation cost recovery
EPA	U.S. Environmental Protection Agency
ER	earnings rate
ERAM	electric rate adjustment mechanism
FCA	fixed cost adjustment
FCM	forward capacity market
FEECA	Florida Energy Efficiency and Conservation Act
FPL	Florida Power and Light
HECO	Hawaiian Electric Company
ISO	independent system operator
kW	kilowatt
kWh	kilowatt-hour
LG&E	Louisville Gas & Electric
LRAM	lost revenue adjustment mechanism
MW	megawatt
MWh	megawatt-hour
NARUC	National Association of Regulatory Utility Commissioners
NJNG	New Jersey Natural Gas

NJR	New Jersey Resources
NJRES	NJR Energy Services
NSP	Northern States Power Company
O&M	operation and maintenance
PBR	performance-based ratemaking
PEB	performance earnings basis
PG&E	Pacific Gas & Electric
RAP	Regulatory Assistance Project
ROE	return on equity
SFV	Straight Fixed-Variable
SJG	South Jersey Gas
UCE	Utah Clean Energy

1: Introduction



Improving the energy efficiency of homes, businesses, schools, governments, and industries—which collectively consume more than 70 percent of the natural gas and electricity used in the United States—is one of the most constructive, cost-effective ways to address the challenges of high energy prices, energy security and independence, air pollution, and global climate change. Mining this efficiency could help us meet on the order of 50 percent or more of the expected growth in U.S. consumption of electricity and natural gas in the coming decades, yielding many billions of dollars in saved energy bills and avoiding significant emissions of greenhouse gases and other air pollutants half to all of the expected load growth for electricity and natural gas over the next 10 to 15 years, yielding many billions of dollars in saved energy bills and avoiding significant emissions of greenhouse gases and other air pollutants. (See the Action Plan's report, available at www.epa.gov/cleanenergy/actionplan/report.htm.)

Recognizing this large untapped opportunity, more than 60 leading organizations representing diverse stakeholders from across the country joined together to develop the National Action Plan for Energy Efficiency (see www.epa.gov/eeactionplan). The Action Plan identifies many of the key barriers contributing to underinvestment in energy efficiency; outlines five key policy recommendations for achieving all cost-effective energy efficiency, focusing largely on state-level energy efficiency policies and programs; and provides a number of options to consider in pursuing these recommendations (Figure 1-1). As of November 2007, nearly 120 organizations have endorsed the Action Plan recommendations and/or made public commitments to implement them in their areas. Aligning utility incentives with the delivery of cost-effective energy efficiency is key to making the Action Plan a reality.

Figure 1-1. National Action Plan for Energy Efficiency Recommendations and Options

Recognize energy efficiency as a high-priority energy resource.

Options to consider:

- Establishing policies to establish energy efficiency as a priority resource.
- Integrating energy efficiency into utility, state, and regional resource planning activities.
- Quantifying and establishing the value of energy efficiency, considering energy savings, capacity savings, and environmental benefits, as appropriate.

Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource.

Options to consider:

- Establishing appropriate cost-effectiveness tests for a portfolio of programs to reflect the long-term benefits of energy efficiency.
- Establishing the potential for long-term, cost-effective energy efficiency savings by customer class through proven programs, innovative initiatives, and cutting-edge technologies.
- Establishing funding requirements for delivering long-term, cost-effective energy efficiency.
- Developing long-term energy saving goals as part of energy planning processes.
- Developing robust measurement and verification procedures.
- Designating which organization(s) is responsible for administering the energy efficiency programs.
- Providing for frequent updates to energy resource plans to accommodate new information and technology.

Broadly communicate the benefits of and opportunities for energy efficiency.

Options to consider:

- Establishing and educating stakeholders on the business case for energy efficiency at the state, utility, and other appropriate level, addressing relevant customer, utility, and societal perspectives.
- Communicating the role of energy efficiency in lowering customer energy bills and system costs and risks over time.
- Communicating the role of building codes, appliance standards, and tax and other incentives.

Provide sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective.

Options to consider:

- Deciding on and committing to a consistent way for program administrators to recover energy efficiency costs in a timely manner.
- Establishing funding mechanisms for energy efficiency from among the available options, such as revenue requirement or resource procurement funding, system benefits charges, rate-basing, shared-savings, and incentive mechanisms.
- Establishing funding for multi-year period.

Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments.

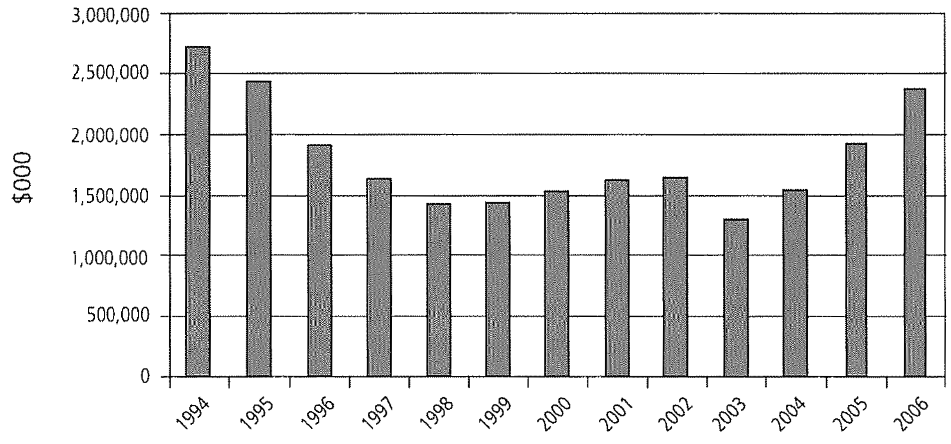
Options to consider:

- Addressing the typical utility throughput incentive and removing other regulatory and management disincentives to energy efficiency.
- Providing utility incentives for the successful management of energy efficiency programs.
- Including the impact on adoption of energy efficiency as one of the goals of retail rate design, recognizing that it must be balanced with other objectives.
- Eliminating rate designs that discourage energy efficiency by not increasing costs as customers consume more electricity or natural gas.
- Adopting rate designs that encourage energy efficiency by considering the unique characteristics of each customer class and including partnering tariffs with other mechanisms that encourage energy efficiency, such as benefit-sharing programs and on-bill financing.

1.1 Energy Efficiency Investment

Actual and prospective investment in energy efficiency programs is on a steep climb, driven by a variety of resource, environmental, and customer cost mitigation concerns. Nevada Power is proposing substantial increases in energy efficiency funding as a strategy for compliance with the state's aggressive resource portfolio standard. Funding in California has roughly doubled since 2004 as utilities supplement public charge monies with "procurement funds."[1] Michigan and Illinois have been debating significant efficiency funding requirements, and the Texas legislature has doubled the percentage of load growth that must be offset by energy efficiency, implying a significant increase in efficiency program funding. Integrated resource planning cases and various regulatory settlements from Delaware to North Carolina and Missouri are producing new investment in energy efficiency. Data recently compiled by the Consortium for Energy Efficiency (2006) show total estimated energy efficiency spending by electric utilities exceeding $2.3 billion in 2006, on par with peak energy efficiency spending in the mid-1990s. With the rise in funding, there is broad interest across the country in refashioning regulatory policies to eliminate financial disincentives and barriers to utility investment in energy efficiency.

Figure 1-2. Annual utility spending on electric energy efficiency.



Sources: EIA, 2006 (for 2005 data); Consortium for Energy Efficiency, 2006.

1.1.1 Understanding Financial Disincentives to Utility Investment

Not unexpectedly, the rise in interest in energy efficiency investment has produced a resurgent interest in how the costs associated with energy efficiency programs are recovered, and whether, in the light of what many believe to be compelling reasons for greater program spending, utilities have sufficient incentive to aggressively pursue these investments.

Energy efficiency programs can have several financial impacts on utilities that create disincentives for utilities to promote energy efficiency more aggressively. Policy-makers have developed several mechanisms intended to minimize or eliminate these impacts:

Table 1-1. Utility Financial Concerns

Potential Impact	Potential Solutions
Energy efficiency expenditures adversely impact utility cash flow and earnings if not recovered in a timely manner.	• Recovery through general rate case • Energy efficiency cost recovery surcharges • System benefits charge
Energy efficiency will reduce electricity or gas sales and revenues and potentially lead to under-recovery of fixed costs.	• Lost revenue adjustment mechanisms that allow recovery of revenue to cover fixed costs • Decoupling mechanisms that sever the link between sales and margin or fixed-cost revenues • Straight fixed-variable (SFV) rate design (allocate fixed costs to fixed charges)
Supply-side investments generate substantial returns for investor-owned utilities. Typically, energy efficiency investments do not earn a return and are, therefore, less financially attractive.[2]	• Capitalize efficiency program costs and include in rate base • Performance incentives that reward utilities for superior performance in delivering energy efficiency

Utility concerns for these three impacts have had a profound effect on energy efficiency investment policy at the corporate and state level for over 20 years, and the concerns continue to create tension as utilities are called upon to boost energy efficiency spending.

Although the nature of today's cost recovery and incentives discussion may be reminiscent of a similar discussion almost two decades ago, the context in which this discussion is taking place is very different. Not only have parties gained valuable experience related to the use of various cost recovery and incentive mechanisms, but the policy landscape has also been reshaped fundamentally.

Industry Structure

The past two decades have witnessed significant industry reorganization in both wholesale and retail power and natural gas markets. Investor-owned electric utilities, particularly in the Northeast and sections of the Midwest, unbundled (i.e., separated the formerly integrated functions of generation, transmission, and distribution) in anticipation of retail competition. Investor-owned natural gas utilities also have gone through a similar unbundling process, albeit one that has been quite different in its form.[3] Unbundling creates two effects relevant to the issues of energy efficiency cost recovery and incentives.

First, unbundling of industry structure also unbundles the value of demand-side programs, in the sense that none of the entities created by unbundling an integrated company can capture the full value of an energy efficiency investment. An integrated utility can capture the value of an energy efficiency program associated with avoided generation, transmission, and distribution costs. The distribution company produced by unbundling an integrated utility can only directly capture the value associated with avoided distribution. One of the principal arguments for public benefits funds was that they could effectively re-bundle this value.[4]

Second, unbundling changes the financial implications of energy efficiency investment as a function of changing cost-of-service structures. The corporate entity subject to continued traditional cost-of-service regulation following unbundling typically is the distribution or wires company. The actual electricity or natural gas sold to consumers is often purchased by consumers directly from competitive or, more commonly, default service providers. In some states, this is also the distribution company. The distribution company adds a distribution service charge to this commodity cost, often levied per unit of throughput, which represents its cost to move the power or gas over its system to the customer. Often, this charge as levied by electric utilities reflects a higher percentage of fixed costs than had been the case when the utility provided bundled service, simply because the utility no longer incurs the variable costs associated with power production.[5] In the case of the distribution company, the potential impact on utility earnings of a drop in sales volume is more pronounced.[6]

Distinctions with a Difference: Gas v. Electric Utilities and Investor Owned v. Publicly and Cooperatively Owned Utilities

Throughout this Report, distinctions are made between gas and electric utilities and between those that are investor- and publicly or cooperatively owned. In some cases, these distinctions create very important differences in how barriers might be perceived and in whether particular cost recovery and incentive mechanisms are applicable and appropriate. For example, gas and electric utilities face very different market dynamics and can have different cost structures. Declining gas use per customer across the industry creates greater financial sensitivity to the revenue impacts of energy efficiency programs. Publicly and cooperatively owned utilities operate under different financial and, in most states, regulatory structures than investor-owned companies. And just the fact that publicly and cooperatively owned utilities are owned by their customers creates a different set of expectations and obligations. At the same time, all utilities are sensitive to many of the same financial implications, particularly regarding recovery of direct program costs and lost margins. Wherever possible over the remainder of this paper, we will highlight specific instances in which these distinctions are particularly important.

Renewed Focus on Resource Planning

Industry restructuring was accompanied by a steep decline in the popularity and practice of resource planning, which had supported much of the early rise in energy efficiency programming. The last several years have seen a resurgence of interest in resource planning (in both bundled and restructured markets) and renewal of interest in ratepayer-funded energy efficiency as a resource option capable of mitigating some of this market volatility.[7]

The intervening years have reshaped the practice of resource planning into a more sophisticated and, sometimes, multi-state process, focused much more on an acknowledgement of and accommodation to the costs and risks surrounding the acquisition of new resources. Energy efficiency investments increasingly are given proper value for their ability to mitigate a variety of policy and financial risks.

Rising Commodity Costs and Flattening Sales

The run-up in natural gas prices over the past several years has made the case for gas utility implementation of energy efficiency programs more compelling as a strategy for helping manage customer energy costs. However, where once these programs were implemented in at least a modestly growing gas market, efficiency programs are now combined with flat or declining use per customer, making recovery of program costs and lost margins a more urgent matter.

Acknowledgement of Climate Risk

There is a growing recognition among state policy-makers and electric utilities that action is required to mitigate the impacts of climate change and/or hedge against the likelihood of costly climate policies. Energy efficiency investments are valued for their ability to reduce carbon emissions at low cost by reducing the use of existing high-carbon emitting sources and the deferral of the need for new fossil capacity. Some of the largest electric utilities in the country are forming their business strategies around the likelihood of action on climate policy, and making energy efficiency pivotal in these strategies. Although the environmental attributes of energy efficiency have long been emphasized in arguing the business case for energy efficiency investment, particularly in the electric industry, today that argument appears largely to be over, and attention is shifting to the practical elements of policies that can support scaled-up investment in efficiency.[8]

As utilities increasingly turn to energy efficiency as a key resource, they will look more closely at the links between efficiency, sales, and financial margins, sharpening the question of whether ratemaking policies that reward increases in sales are sustainable. Perhaps less obvious, as policies are implemented to reduce carbon emissions, they likely will create new pathways for capturing the financial value of efficiency that, in turn, will require policy-makers to consider whether current approaches to cost recovery and incentives are aligned with these broader policies.

Advancing Technology

The technology and therefore, the practice of energy efficiency, appear on the edge of significant transformation, particularly in the electric utility industry. The formerly bright line between energy efficiency and demand response[9] is blurring with the growing adoption of advanced metering technologies, innovative pricing regimes, and smart appliances.[10] Emerging technologies enable utilities to more precisely target valuable load reductions, and offer consumers prices that more closely represent the time-varying costs to provide energy. Ultimately, when consumers can receive and act on time- and location-specific energy prices, this will affect the types of energy efficiency measures possible and needed, and efficiency program design and funding will change accordingly. With respect to the immediate issues of cost recovery and incentives, the incorporation of increasing amounts of demand response in utility resource portfolios can change the financial implications of these portfolios, as programs targeted at peak demand reduction as opposed to energy consumption reduction can have a substantially different impact on the recovery of fixed costs.[11]

1.1.2 Current Status

The answer to "*what has changed?*" then, is that the rationale for investment in efficiency has been rethought, refocused, and strengthened, with ratepayer funding rising to levels eclipsing those of the late 1980s/early 1990s. And as funding rises, the need to address and resolve the issues surrounding energy efficiency program cost recovery and performance incentives take on greater importance and urgency. At the same time, many of the utilities being asked to make this investment are structured differently today than two decades ago during the last efficiency investment boom, so today's efficiency initiatives will have different financial impacts on the utility. The following table presents our best estimate of the current status of energy efficiency cost recovery and utility performance incentive activity across the country. Where a cell reads "Yes" without reference to gas or electric, the policy applies to both gas and electric utilities.

Table 1-2. The Status of Energy Efficiency Cost Recovery and Incentive Mechanisms for Investor-Owned Utilities

	Direct Cost Recovery			Fixed Cost Recovery Revenue Adjustment Mechanism		
State	Rate Case	SBC	Tariff Rider/ Surcharge	Decoupling	Lost Revenue Adjustment Mechanism	Performance
Alabama	Yes			Yes (gas) Pending (electric)		Yes
Alaska				Pending (electric)	Yes	
Arizona	Yes (electric)	Yes (electric)		Pending (gas)		
Arkansas				Yes		Yes
California	Yes	Yes				

State	Direct Cost Recovery			Fixed Cost Recovery Revenue Adjustment Mechanism		Performance
	Rate Case	SBC	Tariff Rider/ Surcharge	Decoupling	Lost Revenue Adjustment Mechanism	
Colorado	Yes		Yes	Yes (gas)		Yes
Connecti-cut		Yes (electric)				Yes
Delaware	Yes					
District of Columbia	Yes			Yes (gas)		
Florida			Yes (electric)	Pending (electric)		
Georgia	Yes			Yes (gas) Pending (electric)		Yes (electric)
Hawaii				Pending (gas)		
Idaho	Yes (electric)			Yes		Yes
Illinois	Yes (electric)			Yes (gas)		
Indiana	Yes					
Iowa	Yes		Yes	Yes (gas)	Yes (electric)	Yes
Kansas						
Kentucky			Yes	Yes (gas)		Yes (electric)
Louisiana						Yes (electric)
Maine		Yes (electric)		Yes		
Maryland						
Massachu-setts		Yes (electric)				
Michigan						
Minnesota	Yes					
Mississippi	Yes			Yes (gas)		Yes (electric)
Missouri					Yes	
Montana	Yes (gas)	Yes (electric)		Pending (gas)		
Nebraska				Yes (gas)		
Nevada	Yes (electric)					Yes

State	Direct Cost Recovery			Fixed Cost Recovery Revenue Adjustment Mechanism		Performance
	Rate Case	SBC	Tariff Rider/ Surcharge	Decoupling	Lost Revenue Adjustment Mechanism	
New Hampshire		Yes (electric)		Pending (electric)		Yes
New Jersey		Yes				
New Mexico	Yes					
New York		Yes (electric)				
North Carolina						
North Dakota						Yes
Ohio			Yes (electric)			
Oklahoma						
Oregon		Yes				
Pennsyl-vania	Yes					
Rhode Island		Yes (electric)				
South Carolina						
South Dakota						
Tennessee						
Texas	Yes					
Utah	Yes (electric)		Yes (electric)			
Vermont		Yes (electric)				
Virginia						
Washing-ton	Yes (electric)		Yes (electric)			
West Virginia						
Wisconsin	Yes (electric)	Yes (electric)				
Wyoming						

Primary source: Kushler et al., 2006. Please see Appendix C for specific state citations.

The table reveals that many states have implemented policies that support cost recovery and/or performance incentives to some extent. Even those states that are not shown as having a specific program cost recovery policy do allow recovery of approved program costs through rate cases. The table also shows that there is a substantial amount of activity surrounding gas revenue decoupling. However, despite the significant level of activity around the country, relatively few states have implemented comprehensive policies that address program cost recovery, recovery of lost margins, and performance incentives. The challenge to policy-makers is whether the level of investment envisioned can be achieved without broader action to implement such comprehensive policies.

1.2 Aligning Utility Incentives with Investment in Energy Efficiency Report

This report on Aligning Utility Incentives with Investment in Energy Efficiency describes the financial effects on a utility of its spending on energy efficiency programs; how those effects could constitute barriers to more aggressive and sustained utility investment in energy efficiency; and how adoption of various policy mechanisms can reduce or eliminate these barriers. This Report also provides a number of examples of such mechanisms drawn from the experience of a number of utilities and states.

The Report was prepared in response to a need identified by the Action Plan Leadership Group (see Appendix A for a list of group members) for additional practical information on mechanisms for reducing these barriers to support the Action Plan recommendations to "provide sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective" and "modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments." Key options to consider under this recommendation include committing to a consistent way to recover costs in a timely manner, addressing the typical utility throughput incentive, and providing utility incentives for the successful management of energy efficiency programs.

There are a number of possible regulatory mechanisms for addressing both options, as well as for ensuring recovery of prudently incurred energy efficiency program costs. Determining which mechanism will work best for any given jurisdiction is a process that takes into account the type and financial structure of the utilities in that jurisdiction, existing statutory and regulatory authority, and the size of the energy efficiency investment. The net impact of an energy efficiency cost recovery and performance incentives policy will be affected by a wide variety of other factors, including rate design and resource procurement strategies, as well as broader considerations such as the rate of demand growth and environmental and resource policies.

Specifically, this report provides a description of three financial effects that energy efficiency spending can have on a utility:

- Failure to recover program costs in a timely way has a direct impact on utility earnings.
- Reductions in sales due to energy efficiency can reduce utility financial margins.
- As a substitute for new supply-side resources, energy efficiency reduces the earnings that a utility would otherwise earn on the supply resource.

This Report examines how these effects create disincentives to utility investment in energy efficiency and the policy mechanisms that have been developed to address these disincentives. In addition, this Report examines the often complex policy environment in which these effects are addressed, emphasizing the need for clear policy objectives and for an approach that explicitly links together the impacts of policies to address utility financial disincentives. Two emerging models for addressing financial disincentives are described, and the Report concludes with a discussion of key lessons for states interested in developing policies to align financial incentives with utility energy efficiency investment.

The subject of financial disincentives and possible remedies has been debated for over two decades, and there remain several unresolved and contentious issues. This Report does not attempt to resolve these issues. Rather, by providing discussion of the financial effects of utility efficiency investment, and of the possible policy options for addressing these effects, this Report is intended to deepen the understanding of these issues. In addition, this Report is intended to provide specific examples of regulatory mechanisms for addressing financial effects for those readers exploring options for reducing financial disincentives to sustained utility investment in energy efficiency.

This Report was prepared using an extensive review of the existing literature on energy efficiency program cost recovery, lost margin recovery, and utility performance incentives—a literature that reaches back over 20 years. In addition, this Report uses a broad review of state statutes and administrative rules related to utility energy efficiency program cost recovery. Key documents for the reader interested in additional information include:

- *Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives,* Martin Kushler, Dan York, and Patti Witte, American Council for an Energy Efficient Economy, Report Number U061, October 2006.
- *Decoupling for Electric and Gas Utilities: Frequently Asked Questions (FAQ),* September 2007, available at http://www.naruc.org.
- A variety of documents and presentations developed by RAP, available online at http://www.raponline.org.
- Ken Costello, *Revenue Decoupling for Natural Gas Utilities--Briefing Paper,* National Regulatory Research Institute, April 2006.
- American Gas Association, *Natural Gas Rate Round-Up, Update on Decoupling Mechanisms—April 2007.*
- DOE, *State and Regional Policies That Promote Energy Efficiency Programs Carried Out by Electric and Gas Utilities: A Report to the United States Congress Pursuant to Section 139 of the Energy Policy Act of 2005,* March 2007.

- *Revenue Decoupling: A Policy Brief of the Electricity Consumers Resource Council,* January 2007.

1.2.1 How to Use This Report

This Report focuses on the issues associated with financial implications of utility-administered programs. For the most part, these issues are the same whether the funding flows from a SBC or is authorized by regulatory action, with the exception that a SBC effectively resolves issues associated with program cost recovery. In addition, the issues related to the effect of energy efficiency on utility financial margins apply whether the efficiency is produced by a utility-administered program or through building codes, appliance standards, or other initiatives aimed at reducing energy use. This Report is intended to help the reader answer the following questions:

- How are utilities affected financially by their investments in energy efficiency?
- What types of policy mechanisms can be used to address the various financial effects of energy efficiency investment?
- What are the pros and cons of these mechanisms?
- What states have employed which types of mechanisms and how have they been structured?
- What are the key differences related to financial impacts between publicly and investor-owned utilities and between electric and gas utilities?
- What new models for addressing these financial effects are emerging?
- What are the important steps to take in attempting to address financial barriers to utility investment in energy efficiency?

This Report is intended for utilities, regulators and regulatory staff, consumer representatives, and energy efficiency advocates with an interest in addressing these financial barriers.

1.2.2 Structure of the Report

Chapter 2 of the Report outlines the basic financial effects associated with utility energy efficiency investment, reviews the key related policy issues, and provides a case study of how a comprehensive approach to addressing financial disincentives to utility energy efficiency investment can have an impact on utility corporate culture. Chapter 3 outlines a range of possible objectives that policy-makers should consider in designing policies to address financial incentives.

Chapters 4, 5, and 6 provide examples of specific program cost recovery, lost margin recovery, and utility performance incentive mechanisms, as well as a review of possible pros and cons. Chapter 7 provides an overview of two emerging cost recovery and performance incentive models, and the Report concludes with a discussion of important lessons for developing a policy to eliminate financial disincentives to utility investment in energy efficiency.

1.2.3 Development of the Report

The Report on Aligning Utility Incentives with Investment in Energy Efficiency is a product of the Year Two Work Plan for the National Action Plan for Energy Efficiency. In addition to direction and comment by the Action Plan Leadership Group, this Guide was prepared with highly valuable input of an Advisory Group. Val Jensen of ICF International served as project manager and primary author of the Report with assistance from Basak Uluca, under contract to the U.S. Environmental Protection Agency.

The Advisory Group members are:

Lynn Anderson	Idaho Public Service Commission
Jeff Burks	PNM Resources
Sheryl Carter	Natural Resources Defense Council
Dan Cleverdon	DC Public Service Commission
Roger Duncan	Austin Energy
Jim Gallagher	New York State Public Service Commission
Marty Haught,	United Cooperative Service
Leonard Haynes	Southern Company
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Barrie McKay	Questar Gas Company
Roland Risser	Pacific Gas & Electric
Gene Rodrigues	Southern California Edison
Michael Shore	Environmental Defense
Raiford Smith	Duke Energy
Henry Yoshimura	ISO New England Inc.

1.3 Notes

1 "Procurement funds" are monies that are approved by the California Public Utilities Commission for procurement of new resources as part of what is essentially an integrated resource planning process in California.

2 Publicly and cooperatively owned utilities operate under different financial structures than investor-owned utilities and do not face the same issue of earnings comparability, as they do not pay returns to equity holders.

3 Unbundling in the gas industry took a much different form than it did in the electric industry. Gas utilities were never integrated, in the sense that they were responsible for production, transmission, and distribution. Gas utilities always have principally served the distribution function. However, prior to the early 1980s, most

gas utilities were responsible for contracting for gas to meet residential, commercial, and industrial demand. Gas industry restructuring led to larger customers being given the ability to purchase gas and transportation service directly, as well as to an end to the typical long-term bundled supply/transportation contracting that gas utilities formerly had engaged in.

4 Some wholesale markets are developing mechanisms to account for the value of demand-side programs. For example, ISO-New England's Forward Capacity Auction allows providers of demand resources to bid demand reductions into the auction.

5 Although natural gas utilities have never had the capital-intensive financial structure common to integrated electric utilities, they historically have tended to be more vulnerable financially to declines in sales because a much greater fraction of the cost of gas service has been associated with the cost of the gas commodity. Prior to gas industry restructuring this problem was even more acute for those utilities procuring gas under contracts with take-or-pay or fixed-charge clauses.

6 According to the Regulatory Assistance Project, the loss of sales due to successful implementation of energy efficiency will lower utility profitability, and the effect may be quite powerful under traditional rate design. "For example, a 5% decrease in sales can lead to a 25% decrease in net profit for an integrated utility. For a stand-alone distribution utility, the loss to net profit is even greater—about double the impact." See Harrington, C., C. Murray, and L. Baldwin (2007). *Energy Efficiency Policy Toolkit.* Regulatory Assistance Project. p. 21. <http://www.raponline.org>

7 A number of studies have examined the ability of energy efficiency and particularly, demand response programs, to reduce power prices by cutting demand during high-price periods. Because the marginal costs of power typically exceed average costs during these periods, efficiency programs targeted at high demand periods often will yield benefits for all ratepayers, even non-participants. See, for example, *Direct Testimony of Bernard Neenan on Behalf of the Citizens Utility Board and the City Of Chicago*, Cub-City Exhibit 3.0 October 30, 2006, ICC Docket No. 06-0617, State Of Illinois, Illinois Commerce Commission.

8 See, for example: "Greenhouse Gauntlet," 2007 CEO Forum, *Public Utilities Fortnightly,* June 2007. Pacific Gas and Electric (2007). *Global Climate Change, Risks, Challenges, Opportunities and a Call to Action.* <http://www.pge.com/includes/docs/pdfs/about_us/environment/features/global_climate_06.pdf>

9 Energy efficiency traditionally has been defined as an overall reduction in energy use due to use of more efficiency equipment and practices, while load management, as a subset of demand response has been defined as reductions or shifts in demand with minor declines and sometimes increases in energy use.

10 There remain important distinctions between dispatchable demand response and energy efficiency, including the ability to participate in wholesale markets.

11 For example, a demand-response program that reduces coincident peak demand but has little impact on sales could lead to a financial benefit for a utility, as its costs might decrease by more than its revenues if the cost of delivering power at the peak period exceeds the price for that power.

12 Diane Munns, former NARUC President and Member of the Iowa Utilities Board, served as co-chair along side James Rogers during the Action Plan's first year.

2: The Financial and Policy Context for Utility Investment in Energy Efficiency

This chapter outlines the potential financial effects a utility may face when investing in energy efficiency and reviews key related policy issues. In addition, it provides a case study of how a comprehensive approach to addressing financial disincentives to utility energy efficiency investment can have an impact on utility corporate culture and explores the issue of regulatory risk.

Investment in energy efficiency programs has three financial effects that map generally to specific types of costs incurred by utilities.

- Failure to recover program costs in a timely way has a direct impact on utility earnings.
- Reductions in sales due to energy efficiency can reduce utility financial margins.
- As a substitute for new supply-side resources, energy efficiency reduces the earnings that a utility would otherwise earn on the supply resource.

How these effects are addressed creates the incentives and disincentives for utilities to pursue investment in energy efficiency. Ultimately, it is the combined effect on utility margins of policies to address these impacts that will determine how well utility financial interests align with investment in energy efficiency.

These effects are artifacts of utility regulatory policy and the general practice of electricity and natural gas rate-setting. Individual state regulatory policy and practice will influence how these effects are addressed in any given jurisdiction. Even where broad consensus exists on the need to align utility and customer interests in the promotion of energy efficiency, the policy and institutional context surrounding each utility dictates the specific nature of incentives and disincentives "on the street." The purpose of this chapter is to briefly review some of the important policy considerations that will affect how the financial implications introduced above are treated.

Two broad distinctions are important when considering policy context. The first is between investor-owned and publicly and cooperatively owned utilities. Every state regulates investor-owned utilities.[1] Most states do not regulate publicly or cooperatively owned utilities except in narrow circumstances. Instead, these entities typically are regulated by local governing boards in the case of municipal utilities, or are governed by boards representing cooperative members. Public and cooperative utilities face many of the same financial implications of energy efficiency investment. They set prices in much the same way as investor-owned utilities, and have fixed cost coverage obligations just as investor-owned utilities do. Because these utilities are owned by their customers, it is commonly accepted that customer and utility interests are more easily aligned. However, because municipal utilities often fund city services through transfers of net operating margins into other city funds, there can be pressure to maintain sales and revenues despite policies supportive of energy efficiency.

The second distinction is between electric and natural gas utilities. This distinction is less between forms of regulation and more between the nature of the gas and electric utility businesses. Natural gas utilities historically have operated as distributors. Although many gas utilities continue to purchase gas on behalf of customers, the costs of these purchases are simply passed through to customers without mark-up. Many electric utilities, by contrast, build and operate generating facilities. Thus, the capital structures of the two types of utilities have differed significantly.[2] Electric utilities, while more capital intensive in the aggregate, historically have had higher variable costs of operation relative to the total cost of service than gas utilities. In other words, while electric utilities required more capital, fixed capital costs represented a larger fraction of the jurisdictional revenue requirement for gas utilities. This has made gas utilities more sensitive to unexpected sales fluctuations and fostered greater interest in various forms of lost margin recovery.

Much of the discussion of mechanisms for aligning utility and customer interests related to energy efficiency investment assumes the utility is an investor-owned electric utility. However, some issues and their appropriate resolution will differ for publicly and cooperatively owned utilities and for natural gas utilities. These differences will be highlighted where most significant.

This chapter reviews each of the three financial effects of utility energy efficiency spending and then briefly examines some of the policy issues that each raises. More detailed examples of policy mechanisms for addressing each effect are provided in following chapters.

2.1 Program Cost Recovery

The first effect is associated with energy efficiency program cost recovery—recovery of the direct costs associated with program administration (including evaluation), implementation, and incentives to program participants. Reasonable opportunity for program cost recovery is a necessary condition for utility program spending. Failure to recover these costs produces a direct dollar-for-dollar reduction in utility earnings, and discourages further investment. If, for whatever reason, a utility is unable to recover $500,000 in costs associated with an energy efficiency program, it will see a $500,000 drop in its net margin.

Policies directing utilities to undertake energy efficiency programs in most cases authorize utilities to seek recovery of program costs, even though actual recovery of all costs is never guaranteed.[3] Clarity with respect to the cost recovery process is critical, as broad uncertainty regarding the timing and threshold burden of proof can itself constitute almost as much a disincentive to utility investment as actual refusal to allow recovery of program costs.[4] A reasonable and reliable system of program cost recovery, therefore, is a necessary first element of a policy to eliminate financial disincentives to utility investment in energy efficiency.

Policy-makers have a wide variety of tools available to them to address cost recovery. These tools can have very different financial implications depending on the specific context. More important, history has shown that recovery is not, in fact, a given. Chapter 5 provides a more complete treatment of program cost recovery mechanisms. However, with respect to the broader policy context, several points are important to note here. All are related to risk.

2.1.1 Prudence

State regulatory commissions, as well as the governing boards of publicly and cooperatively owned utilities, have fundamental obligations to ensure that the costs passed along to ratepayers are just and reasonable and were prudently incurred. Sometimes commissions have found these costs to be appropriately born by shareholders (such as "image advertising") rather than ratepayers. Other times, costs are disallowed because they are considered "unreasonable" for the good or service procured or delivered. Finally, regulators and boards might determine that a certain activity would not have been undertaken by prudent managers and thus costs associated with the activity should not be recoverable from ratepayers.

While within the scope of regulatory authority,[5] such disallowances can create some uncertainty and risk for utilities if the rules governing prudence and reasonableness are not clear.[6] Regulated industries traditionally have been viewed as risk averse, in part because with their returns regulated, risk and reward are not symmetrical. Utilities that have been faced with significant disallowances tend to be particularly averse to incurring any cost that is not pre-approved or for which there is a risk that a particular expense will be disallowed.

Program cost recovery requires a negotiation between regulators and utilities to create more certainty regarding prudence and reasonableness and therefore, to assure utilities that energy efficiency costs will be recoverable. Many states provide this balance by requiring utilities to submit energy efficiency portfolio plans and budgets for review and sometimes approval.[7] The utility receives assurance that its proposed expenditures are *decisionally prudent*, and regulators are assured that proposed expenditures satisfy policy objectives. Such pre-approval processes do not preclude regulatory review of actual expenditures or findings that actual program implementation was imprudently managed.

2.1.2 The Timing of Cost Recovery

Cost recovery timing is important for two reasons:

1. If there is a significant lag between a utility's expenditure on energy efficiency programs and recovery of those costs, the utility incurs a carrying cost—it must finance the cash flow used to support the program expenditure. Even if a utility has sufficient cash flow to support program funding, these funds could have been applied to other projects were it not for the requirement to implement the program.

2. The length of the time lag directly affects a utility's perception of cost recovery risk. The composition of regulatory commissions and boards changes frequently and while commissions may respect the decisions of their predecessors, they are not bound to them. Therefore, a change in commissions can lead to changes in or reversals of policy. More important, the longer the time lag, the greater the likelihood that unexpected events could occur that affect a utility's cash flow.

The timing issues can be addressed in several ways. The two most prevalent approaches are to allow a utility to book program costs in a deferral account with an appropriate carrying charge applied, or to establish a tariff rider or surcharge that the utility can adjust periodically to reflect changes in program costs. Neither approach precludes regulators from reviewing actual costs to determine reasonableness and making appropriate adjustments. However, the deferral approach can create what is known as a regulatory asset, which can rapidly grow and, when it is added to the utility's cost of service, cause a jump in rates depending on how the asset is treated.[8]

2.2 Lost Margin Recovery

Defining Terms

A variety of terms are used to describe the financial effect of a reduction in utility sales caused by energy efficiency. All of these relate to the practice of traditional ratemaking, wherein some portion of a utility's fixed costs are recovered through a volumetric charge. Because these costs are fixed, higher-than-expected sales will lead to higher-than-expected revenue and possible over-recovery of fixed costs. Lower-than-expected sales will lead to under-recovery of these costs. The terminology used to describe the phenomenon and its impacts can be confusing, as a variety of different terms are used to describe the same effect. Key terms include:

- **Throughput**—utility sales.
- **Throughput incentive**—the incentive to maximize sales under volumetric rate design.
- **Throughput disincentive** - the disincentive to encourage anything that reduces sales under traditional volumetric rate design.
- **Fixed-cost recovery**—the recovery of sufficient revenues to cover a utility's fixed costs.
- **Lost revenue**—the reduction in revenue that occurs when energy efficiency programs cause a drop in sales below the level used to set the electricity or gas price. There generally also is a reduction in cost as sales decline, although this reduction often is less than revenue loss.
- **Lost margin**—the reduction in revenue to cover fixed costs, including earnings or profits in the case of investor-owned utilities. Similar to lost revenue, but concerned only with fixed-cost recovery, or with the opportunity costs of lost margins that would have been added to net income or created a cash buffer in excess of that reflected in the last rate case. The amount of margin that might be lost is a function of both the change in revenue and the any change in costs resulting from the change in sales.

The National Action Plan for Energy Efficiency used *throughput incentive* to describe this effect. Where possible, this Report will also use that phrase. It will also describe the effect using the phrases *under-recovery of margin revenue* or *lost margins,* for the most part to describe issues related to the effect of energy efficiency on recovery of fixed costs.

The objective of an energy efficiency program is to cost-effectively reduce consumption of electricity or natural gas. However, reducing consumption also reduces utility revenues and, under traditional rate designs that recover fixed costs through volumetric charges, lower revenues often lead to under-recovery of a utility's fixed costs. This, in turn, can lead to lower net operating margins and profits and what is termed the "*lost margin*" effect. This same effect can create an incentive in certain cases for utilities to try to increase sales and thus, revenues, between rate cases—this is known as the *throughput incentive*. Because fixed costs (including financial margins) are recovered through volumetric charges, an increase in sales can yield increased earnings, as long as the costs associated with the increased sales are not climbing as fast.

Treatment of lost margin recovery, either in a limited fashion or through some form of what is known as "*decoupling*," raises basic issues of not only what the regulatory obligation is with regard to utility earnings, but also of the regulators' role in determining the utility's business model. Few energy efficiency policy issues have produced as much debate as the issue of the impact of energy efficiency programs on utility margins (Costello, 2006; Eto et al., 1994; National Action Plan for Energy Efficiency, 2006; Sedano, 2006).

2.2.1 Defining Lost Margins

The lost margin effect is a direct result of the way that electricity and natural gas prices are set under traditional regulation. And while the issue might be more immediate for investor-owned utilities where profits are at stake, the root financial issues are the same whether the utility is investor-, publicly, or cooperatively owned.

Traditional cost-of-service ratemaking is based on the same simple arithmetic used in Table 2-1 on the next page.[9]

average price = revenue requirement/estimated sales[10]

revenue requirement = variable costs + depreciation + other fixed costs + (capital costs × rate of return)

revenue = actual sales × average price

Capital costs are equal to the original cost of plant and equipment used in the generation, transmission, and distribution of energy, minus accumulated depreciation. The rate of return, in the case of an investor-owned utility, is a weighted blend of the interest cost on the debt used to finance the plant and equipment and an ROE that represents the return to shareholders. The dollar value of this ROE generally represents allowed profit or "margin." Publicly and cooperatively owned utilities do not earn profit per se, and so the rate of return for these enterprises is the cost of debt.[11] The sum of depreciation, other fixed costs (e.g., fixed O&M, property taxes, labor), and the dollar return on invested capital represents a utility's total fixed costs.

If actual sales fall below the level estimated when rates are set, the utility will not collect revenue sufficient to match its authorized revenue requirement. The portion of the revenue requirement most exposed is a utility's margin. For legal and financial reasons, a utility will use available revenues to cover the costs of interest, depreciation, property taxes, and so forth, with any remaining revenues going to this margin, representing profit for an investor-owned utility.[12,13]

Table 2-1. The Arithmetic of Rate-Setting

	Baseline (rate setting proceeding)	Case 1 (2% reduction in sales)	Case 2 (2% increase in sales)
1. Variable costs	$1,000,000	$980,000	$1,020,000
2. Depreciation + other fixed costs	$500,000	$500,000	$500,000
3. Capital cost	$5,000,000	$5,000,000	$5,000,000
4. Debt	$3,000,000	$3,000,000	$3,000,000
5. Interest (@10%)	$300,000	$300,000	$300,000
6. Equity	$2,000,000	$2,000,000	$2,000,000
7. Rate of return on equity (ROE@ 10%)	10%	10%	10%
8. Authorized earnings	$200,000	$200,000	$200,000
9. Revenue requirement (1+2+5+8)	$2,000,000	$1,980,000	$2,020,000
10. Sales (kWh)	20,000,000	19,600,000	20,400,000
11. Average price (9÷10)	$0.10	$0.101	$0.99
12. Earned revenue (11×10)	$2,000,000	$1,960,000	$2,040,000
13. Revenue difference (12–9)	0	-$40,000	+$40,000
14. % of authorized earnings (13÷8)	0	-20%	+20%

If sales rise above the levels estimated in a rate-setting process, a utility will collect more revenue than required to meet its revenue requirement, and the excess above any increased costs will go to higher earnings.[14] The following table provides an example based on an investor-owned utility, and Chapter 4 of the Action Plan—the Business Case for Energy Efficiency—provides a very clear illustration of this impact under a variety of scenarios. The results illustrated are sensitive to the relative proportion of fixed and variable costs in a utility's cost of service. The higher the proportion of the variable costs, the lower the impact of a drop in sales. A gas utility's cost-of-service typically will have a higher proportion of fixed costs than an electric utility's and, therefore, the gas utility can be more financially sensitive to changes in sales relative to a test year level.[15]

This example only examines the impact on earnings due to a sales-produced change in revenue. Margins obviously also are affected by costs, and while many costs are considered fixed in the sense that they do not vary as a function of sales, they are under the control of utilities. Therefore, increases in sales and revenue above a test year level do not necessarily translate into higher margins, and the impact of a reduction in sales on margins depends on how a utility manages its costs.

Although the revenue difference appears small, it can be significant due to the effects on financial margins. The Case 1 revenue deficit of $40,000 represents 20 percent of the allowed ROE. In other words, a 2 percent drop in sales below the level assumed in the rate case translates into a 20 percent drop in earnings or margin, all else being equal. Similarly, sales that are 2 percent higher than assumed yield a 20 percent increase in earnings above authorized levels.

The magnitude of the impact is, in this example, directly related to the efficacy of the efficiency program. Many other factors can have a similar impact on utility revenues—for instance, sales can vary greatly from the rate case forecast assumptions due to weather or economic conditions in the utility's service territory. But unlike the weather or the economy, energy efficiency is the most important factor affecting sales that lies within the utility's control or influence, and successful energy efficiency programs can reduce sales enough to create a disincentive to engage in such programs.

In Case 2, actual sales exceed estimated levels. Once rates are set, a utility may have a financial incentive to encourage sales in excess of the level anticipated during the rate-setting process, since additional units of energy sold compensate for any unanticipated increased costs, and may improve earnings.[16]

Chapter 5 explores mechanisms that can be used to address both cases. Generally, two approaches have been used. First, several states have implemented what are termed lost revenue adjustment mechanisms (LRAMs) that attempt to estimate the amount of fixed-cost or margin revenue that is "lost" as a result of reduced sales. The estimated lost revenue is then recovered through an adjustment to rates. The second approach is known generically as "decoupling." A decoupling mechanism weakens or eliminates the relationship between sales and revenue (or more narrowly, the revenue collected to cover fixed costs) by allowing a utility to adjust rates to recover authorized revenues independent of the level of sales. Decoupling actually can take many forms and include a variety of adjustments.

LRAM and decoupling not only represent alternative approaches to addressing the lost margins effect, but they also reflect two different policy questions related to the relationship between utility sales and profits.

Provide compensation for lost margins?

Should a utility be compensated for the under-recovery of allowed margins when energy efficiency programs—or events outside of the control of the utility, such as weather or a drop in economic activity—reduce sales below the level on which current rates are based? The financial implication—with all else being held equal—is easy to illustrate as shown in Table 4-1. In practice, however, determining what is lost as a direct result of the implementation of energy efficiency programs is not so simple. The determination of whether this loss should stand alone or be treated in context of all other potential impacts on margins also can be challenging. For example, during periods between rate cases, revenues and costs are affected by a wide variety of factors, some within management control and some not. The impacts of a loss of revenue due to an energy efficiency program could be offset by revenue growth from customer growth or by reductions in costs. On the other hand, the addition of new customers imposes costs which, depending on rate structure, can exceed incremental revenues.

Change the basic relationship between sales and profit?

Should lost margins be addressed as a stand-alone matter of cost recovery, or should they be considered within a policy framework that changes the relationship between sales, revenues, and margins—in other words by decoupling revenues from sales? Decoupling not only addresses lost margins due to efficiency program implementation. It also removes the incentive a utility might otherwise have to increase throughput, and can reduce resistance to policies like efficient building codes, appliance standards, and aggressive energy efficiency awareness campaigns that would reduce throughput.

Decoupling also can have a significant impact on both utility and customer risk. For example, by smoothing earnings over time, decoupling reduces utility financial risk, which some have argued can lead to reductions in the utility's cost-of-capital. (For a discussion of this issue, see Hansen, 2007, and Delaware PSC, 2007.) Depending on precisely how the decoupling mechanism is structured, it can shift some risks associated with sales unpredictability (e.g., weather, economic growth) to consumers.[17] This is a design decision within the control of policy-makers, and not an inherent characteristic of decoupling. The issue of the effect of decoupling on risk and therefore, on the cost-of-capital, likely will receive greater attention as decoupling increasingly is pursued. The existing literature and current experience is inconclusive, and the policy discussion would benefit from a more complete examination of the issue than is possible in this Report.

Ultimately, the policy choice must be made based on practical considerations and a reasonable balancing of interests and risks. Most observers would agree that significant and sustained investment in energy efficiency by utilities, beyond that required by statute or order, will not occur absent implementation of some type of lost margin recovery mechanism. More important, a policy that hopes to encourage aggressive utility investment in energy efficiency most likely will not fundamentally change utility behavior as long as utility margins are directly tied to the level of sales. The increasing number of utility commissions investigating decoupling is clear evidence that this question has moved front and center in development of energy efficiency investment policies across the country.

2.3 Performance Incentives

The first two financial impacts described above pertain to obvious disincentives for utilities to engage in energy efficiency program investment. The third effect concerns incentives for utilities to undertake such investment. Full recovery of program costs and collection of allowed revenue eliminates potential financial penalties associated with funding energy efficiency programs. However, simply eliminating financial penalties will not fundamentally change the utility business model, because that model is premised on the earnings produced by supply-side investment. In fact, the earnings inequality between demand- and supply-side investment even where program costs and lost margins are addressed can create a significant barrier to aggressive investment in energy efficiency. An enterprise organized to focus on and profit by investment in supply is not easily converted to one that is driven to reduce demand. This is particularly true in the absence of clear financial incentives or fundamental changes in the business environment.[18]

This issue is fundamental to a core regulatory function—balancing a utility's obligation to provide service at the lowest reasonable cost and providing utilities the opportunity to earn reasonable returns. For example, assume that an energy efficiency program can satisfy an incremental resource requirement at half the cost of a supply-side resource, and that in all other financial terms the efficiency program is treated like the supply resource. Cost recovery is assured and lost margins are addressed. In this case, the utility will earn 50 percent of the return it would earn by building the power plant. Consumers as a whole clearly would be better off by paying half as much for the same level of energy service. However, the utility's earnings expectations are now changed, with a potential impact on its stock price, and total returns to shareholders could decline. There could be additional benefits, to the extent that investors perceive the utility less vulnerable to fuel price or climate risk, but under the conventional approach to valuing businesses, the utility would be less attractive. This is an extreme example, and it is more likely that this trade-off plays out more modestly over a longer period of time. Nevertheless, the prospective loss of earnings from a shift towards greater reliance on demand-side resources is a concern among investor-owned utilities, and it will likely influence some utilities' perspective on aggressive investment in energy efficiency.[19]

The importance of performance incentives is not universally accepted. Some parties will argue that utilities are obligated to pursue energy efficiency if that is the policy of the State. Those taking this view will see performance incentives as requiring customers to pay utilities to do something that should be done anyway. Others have argued that the basic business of a utility is to deliver energy, and that providing financial incentives over-and-above what could be earned by efficient management of the supply business simply raises the cost of service to all customers and distorts management behavior.

Those holding this latter view often prefer that energy efficiency investment be managed by an independent third-party (see, for example, ELCON, 2007). Existing third-party models, such as those in Oregon, Vermont, and Wisconsin, have received generally high marks, but these models carry a variety of implications beyond those related to lost margins and performance incentives. Policy-makers interested in a third party model must balance the potentially beneficial effects for ratepayers with what is typically a lower level of control over the third party, and increased complexity in integrating supply- and demand-side resource policy.

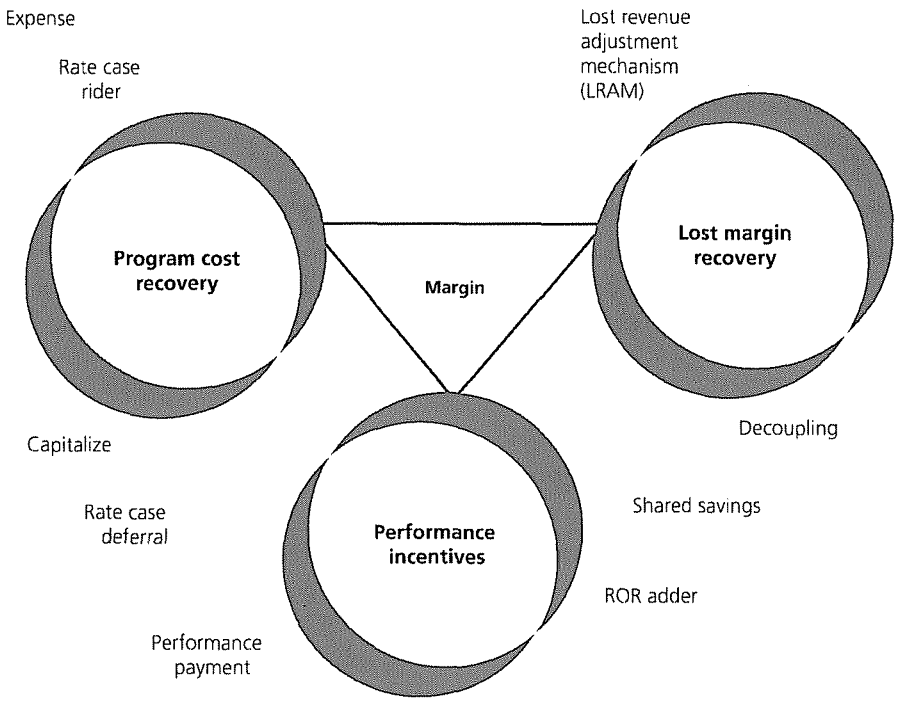
Apart from this threshold issue, regulators face a variety of options for providing incentives to utilities (see Chapter 7), ranging from mechanisms that tie a financial reward to specific performance metrics, including savings, to options that enable a sharing of program benefits, to rewards based on levels of program spending.[20] The latter type of mechanism, while sometimes derided as an incentive to spend, not save, has been applied in some cases simply because it is easier to develop and implement, and it can be combined with pre- and post-implementation reviews to ensure that ratepayer funds are being used effectively.

Providing financial incentives to a utility if it performs well in delivering energy efficiency potentially can change the existing utility business model by making efficiency profitable rather than merely a break-even activity. Today such incentives are the exception rather than the norm. For example, California policy-makers have acknowledged that successfully reorienting utility resource acquisition policy to place energy efficiency first in the resource "loading order" requires that performance incentives be re-instituted (see CPUC, 2006).

2.4 Linking the Mechanisms

Each of the financial effects suggests a different potential policy response, and policy-makers can and have approached the challenge in a variety of ways. It is the net financial effect of a package of cost recovery and incentive policies that matters in devising a policy framework to stimulate greater investment in energy efficiency. A variety of policy combinations can yield roughly the same effect. However, to the extent that mechanisms are developed to address all financial effects, care must be taken to ensure that the interactions among these are understood.

Figure 2-1. Linking cost recovery, recovery of lost margins, and performance incentives.



The essential foundation of the policy framework is program cost recovery. While confidence in its ability to recover these direct costs is central to a utility's willingness to invest in energy efficiency, a number of options are available for recovery, some of which also address lost margins and performance incentives. Some states directly provide for lost margin recovery for losses due to efficiency programs through a decoupling or LRAM while others create performance incentive policies that indirectly compensate for some or all lost margins. Minnesota, for example, abandoned its lost margin recovery mechanism in favor of a performance incentive after finding that levels of margin recovery had become so large that their recovery could not be supported by the commission. Although it has been difficult to determine the precise impact of the change in policy, the utilities in Minnesota have indicated that they are generally satisfied given that prudent program cost recovery is guaranteed and significant performance incentives are available.[21,22] Finally, the combination of program cost recovery and a decoupling mechanism could create a positive efficiency investment environment, even absent performance incentives. Depending on its structure, a decoupling mechanism can create more earnings stability, which, all else being equal, can reduce risk.[23]

2.5 "The DNA of the Company": Examining the Impacts of Effective Mechanisms on the Corporate Culture

A policy that addresses all three financial effects will, in theory, have a powerful impact on utility behavior and, ultimately, corporate culture, turning what for many utilities is a compliance function into a key element of business strategy.[24] Perhaps the clearest example of this is Pacific Gas & Electric.

PG&E has one of the richest histories of investment in energy efficiency of any utility in the country, dating to the late 1970s. A vital part of that history has been California's policy with respect to program cost recovery, treatment of fixed-cost recovery and performance incentives. Decoupling, in the form of electric rate adjustment mechanism (ERAM), was instituted in 1982. ERAM was suspended as the state embarked on its experiment with utility industry restructuring. While that specific mechanism has not been reinstituted, 2001 legislation effectively required reintroduction of decoupling, which each investor-owned utility has pursued, though in slightly different forms. Similarly, utility performance incentives were authorized more than a decade ago, but were suspended in 2002 amidst of a broad rethinking of the administrative structure for energy efficiency investment in the State. A September 2007 decision by the California Public Utilities Commission (CPUC), reinstated utility performance incentives through an innovative risk/reward mechanism offering utilities collectively up to $450 million in incentives over a three-year period. At the same time, this mechanism will impose penalties on utilities for failing to meet performance targets (see Section 7.2 below for a more complete description).

The policy framework in California supports very aggressive investment in energy efficiency, placing energy efficiency first in the resource loading order through adoption of the state's Energy Action Plan. The Energy Action Plan also established that utilities should earn a return on energy efficiency investments commensurate with foregone return on supply-side assets. Public proceedings directed by the Public Utilities Commission set three-year goals for each utility, and the payment of performance incentives will be based on meeting these goals.

PG&E's current energy efficiency investment levels are approaching an all-time high, totaling close to $1 billion over the 2006–2008 period. Base funding comes from the state's public goods charge, but a substantial fraction now comes as the result of the State's equivalent of integrated resource planning proceedings. These procurement proceedings, through which the loading order is implemented, will continue to maintain energy efficiency funding at levels in excess of the public goods charge, as the state pursues aggressive savings goals.

A view only to savings targets and spending levels might suggest that a discussion of disincentive to investment and utility corporate culture is irrelevant in PG&E's case. However, support for these aggressive investments appears to be run deep within the California investor-owned utilities, and clearly this policy would struggle were it not for utility support. Even so, has this policy actually shaped utility corporate culture?

Discussions with PG&E management suggest the answer is "yes" (personal communication with Roland Risser, Director of Customer Energy Efficiency, Pacific Gas & Electric Company, May 2, 2007). Although investment levels always have been high in absolute terms, the company's view in the 1980s initially had been that, as long as energy efficiency investment did not hurt financially, the company would not resist that investment. However, the combined effect of ERAM and utility performance incentives turned what had been a compliance function into a vital piece of the company's business, and a defining aspect of corporate culture that has produced the largest internal energy efficiency organization in the country.[25]

The policy and financial turbulence created by the state's attempt at industry restructuring challenged this culture, first as ERAM and performance incentives were halted, and then as the regulatory environment turned sour with the energy crisis. However, a combination of a new policy recommitment to demand-side management (DSM), and the arrival of a new PG&E CEO have combined to reset the context for utility investment in efficiency and strengthen corporate commitment. Decoupling is again in place and the public utilities commission has adopted a new performance incentive structure.

The significant escalation in efficiency funding driven by California's Energy Action Plan, in addition to resource procurement proceedings, required the company to address the role of energy efficiency investment in more fundamental terms internally. The choices made in the procurement proceedings allocated funding to energy efficiency resources—funding that otherwise would have gone to support acquisition of conventional supply. While in most organizations such allocation processes can create fierce competition, the environment within PG&E has significantly reduced potential conflict and even more firmly embedded energy efficiency in the company's clean energy strategy.

The culture shift certainly is the product of a combination of forces, including the arrival of a new CEO with a strong commitment to climate protection; a state policy environment that is intensely focused on clean energy development; an investment community interested in how utilities hedge their climate risks; and the re-emergence of favorable treatment of fixed-cost coverage and performance incentives. It is not clear that progressive cost recovery and incentive policies are solely responsible for this change, but without these policies it is unlikely that efficiency investment would have become a central element of corporate strategy, embedded "in the DNA of the Company" (personal communication with Roland Risser, PG&E).

Would the same cost recovery and incentive structure have the same effect elsewhere? That answer is unclear, though it is unlikely that simply adopting mechanisms similar to what are in place in California would effect overnight change. Corporate culture is formed over extended periods of time and is influenced by the whole of an operating environment and the leadership of the company. Nevertheless, according to senior PG&E staff, the effect of the cost recovery and incentive policies is undeniable—in this case it was the catalyst for the change.

2.6 The Cost of Regulatory Risk

A comprehensive cost recovery and incentive policy can help institutionalize energy efficiency investment within a utility. At the same time, the absence of a comprehensive approach, or the inconsistent and unpredictable application of an approach, can create confusion with respect to regulatory policy and institutionalize resistance to energy efficiency investment. A significant risk that policy-makers could disallow recovery of program costs and/or collection of incentives, even if such investments have been encouraged, imposes a real, though hard-to-quantify cost on utilities. While a significant disallowance can have direct financial implications, a less tangible cost is associated with the institutional friction a disallowance will create. Organizational elements within a utility responsible for energy efficiency initiatives will find it increasingly difficult to secure resources. Programs that are offered will tend to be those that minimize costs rather than maximize savings or cost-effectiveness. Easing this friction will not be as simple as a regulatory message that it will not happen again, and in fact the disallowance could very well have been justified, should have happened, and would happen again.

Regulators clearly cannot give up their authority and responsibility to ensure just and reasonable rates based on prudently incurred costs. And changes in the course of policy are inevitable, making flexibility and adaptability essential. All parties must realize, however, that the consistent application of policy with respect to cost recovery and incentives matters as much if not more than the details of the policies themselves. The wide variety of cost recovery and incentive mechanisms provides opportunities to fashion a similar variety of workable policy approaches. Significant and sustained investment in energy efficiency by utilities very clearly requires a broad and firm consensus on investment goals, strategy, investment levels, measurement, and cost recovery. It is this consensus that provides the necessary support for consistent application of cost recovery and incentives mechanisms.[26]

2.7 Notes

1 However, as they explored industry restructuring, a number of states stripped utility commissions of regulatory authority over generation and, in some cases, transmission to varying degrees.

2 In fact, many gas utilities do make investment in plant and equipment beyond gas distribution pipes--gas peaking and storage facilities, for example.

3 Recovery of costs always is based on demonstration that the costs were prudently incurred.

4 The forward period for which energy efficiency program costs is approved can be quite important to the success of programs. Year-by-year approval requirements complicate program planning, and longer term commitments to the market actors cannot be made. The trend among states is to move toward longer program implementation periods, e.g., three years. Thus, to the extent that program costs are reviewed as part of proposed implementation plans, initial approval for spending is conferred for the three-year period, providing program stability and flexibility.

5 Courts can rule on appeal that regulatory disallowances were not supported by the facts of a case or by governing statute.

6 In fact, some such disallowances have had the effect of clarifying these rules.

7 Another approach to achieving this balance is using stakeholder collaboratives to review, help fashion, and, where appropriate based on this review, endorse certain utility decisions. Where these collaboratives produce stipulations that can be offered to regulators, they provide some additional assurance to regulators that parties who might otherwise challenge the prudence or reasonableness of an action, have reviewed the proposed action and found it acceptable. Though sometimes time-and resource-intensive, such collaboratives have been helpful tools for reducing utility prudence risk related to energy efficiency expenditures.

8 In addition, because such regulatory asset accounts are backed not by hard assets but by a regulatory promise to allow recovery, their use can raise concern in the financial community particularly for utilities with marginal credit ratings.

9 The lost margin issue actually arises as a function of rate designs that intend to recover fixed costs through volumetric (per kilowatt-hour or therm) charges. A rate design that placed all fixed costs of service in a fixed charge per customer (SFV rate) would largely alleviate this problem. However such rates significantly reduce a consumer's incentive to undertake efficiency investments, since energy use reductions would produce much lower customer bill savings relative to a the situation under a rate design that included fixed costs in volumetric charges. In addition, fixed-variable rates are criticized as being regressive (the lower the use, the higher the average cost per unit consumed) and unfair to low-income customers. See Chapter 5, "Rate Design," of the Action Plan for an excellent discussion of this process.

10 This equation is a simplification of the rate-setting process. The actual rates paid per kilowatt-hour or therm often will be higher or lower than the average revenue per unit.

11 Note, however, that publicly owned utilities typically must transfer some fraction of net operating margins to other municipal funds, and cooperatively owned utilities typically pay dividends to the member of the co-op. These payments are the practical equivalent of investor-owned utility earnings. In addition, these utilities typically must meet bond covenants requiring that they earn sufficient revenue to cover a multiple of their interest obligations. Therefore, there can be competing pressures for publicly and cooperatively owned utilities to maintain or increase sales at the same time that they promote energy efficiency programs.

12 Although a utility is not obligated to pay returns to shareholders in the same sense that it is obligated to pay for fuel or to pay the interest associated with debt financing, failure to provide the opportunity to earn adequate returns will lead equity investors to view the utility as a riskier or less desirable investment and will require a higher rate of return if they are to invest in the utility. This will increase the utility's overall cost of service and its rates.

13 Publicly and cooperatively owned utilities do not earn profits per se and thus, have no return on equity. However, they do earn financial margins calculated as the difference between revenues earned and the sum of variable and fixed costs. These margins are important as they fund cooperative member dividends and payments to the general funds of the entities owning the public utilities.

14 The actual impact on margins of a change in sales depends critically on the extent to which fixed costs are allocated to volumetric charges. Actual electricity and natural gas prices usually include both a fixed customer charge and a price per unit of energy consumed. The larger the share of fixed costs included in this price per unit, the more a utility's margin will fluctuate with changes in sales.

15 A gas utility's cost of service does not include the actual commodity cost of gas which is flowed through directly to customers without mark-up.

16 Some states require utilities to participate in a rate case every two or three years. Others hold rate cases only when a utility believes it needs to change its prices in light of changing costs or the regulatory agency believes that a utility is over-earning.

17 Unless properly structured, a decoupling mechanism also can lead to a utility over-earning—collecting more margin revenue than it is authorized to collect.

18 An alternative has been for state utility commissions to require adherence to least-cost planning principles that require the less expensive energy efficiency to be "built," rather than the new supply-side resource. However, this approach does not alter the basic financial landscape described above.

19 The California Public Utilities Commission's recent ruling regarding utility performance rewards explicitly recognized this issue.

20 The actual implementation of an incentive mechanism may address more than financial incentives. For example, The Minnesota Commission considers its financial incentive mechanism as effectively addressing the financial impact of the reduction in revenue due to an energy efficiency program.

21 State EE/RE Technical Forum Call #8, Decoupling and Other Mechanisms to Address Utility Disincentives for Implementing Energy Efficiency, May 19, 2005. <http://www.epa.gov/cleanenergy/stateandlocal/efficiency.htm#decoup>

22 The Minnesota Legislature recently adopted legislation directing the Minnesota Public Service Commission to adopt criteria and standards for decoupling, and to allow one or more utilities to establish pilot decoupling programs. S.F. No. 145, 2nd Engrossment 85th Legislative Session (2007-2008).

23 As noted, some argue that this risk reduction should translate into a corresponding reduction in the cost of capital, although views are mixed regarding the extent to which this reduction can be quantified.

24 For a broader discussion of how cost recovery and incentive mechanisms can affect the business model for utility investment in energy efficiency, see NERA Economic Consulting (2007). *Making a Business of Energy Efficiency: Sustainable Business Models for Utilities. Prepared for Edison Electric Institute.*

25 This infrastructure was significantly scaled back during California's restructuring era.

26 One way to manage the regulatory risk issue is to make the regulatory goals very clear and long-term in nature. Setting energy savings targets—for example, by using an Energy Efficiency Resource Standard—can remove some part of the utility's risk. If the utility meets the targets, and can show that the targets were achieved cost-effectively, prudence and reasonableness are easier to establish, and cost recovery and incentive payments become less of an issue. Otherwise, more issues are under scrutiny: did the utility seek "enough" savings? Did it pursue the "right" technologies and markets? With a high-level, simple, and long-term target, such issues become less germane.

3: Understanding Objectives—Developing Policy Approaches That Fit

This chapter explores a range of possible objectives for policy-makers' consideration when exploring policies to address financial disincentives. It also addresses the broader context in which these objectives are pursued.

Each jurisdiction could value the objectives of the energy efficiency investment process and the objectives of cost recovery and incentive policy design differently. Jurisdictional approaches are formed by a variety of statutory constraints, as well as by the ownership and financial structures of the utilities; resource needs; and related local, state, and federal resource and environmental policies. ***The overarching objective in every jurisdiction that considers an energy efficiency investment policy should be to generate and capture substantial net economic benefits.*** This broad objective sometimes is expressed as a spending target, but more often as an energy or demand reduction target, either absolute (e.g., 500 MW by 2017) or relative (e.g., meet 10, 50, or 100 percent of incremental load growth or total sales). Increasingly, states are linking this objective to others that promote the use of cost-effective energy efficiency as an environmentally preferred option. The objectives outlined below guide how a cost recovery and incentive policy is crafted to support this overarching objective.

3.1 Potential Design Objectives

A review of the cost recovery and incentive literature, as well as the actual policies established across the country, reveals a fairly wide set of potential policy objectives. Each one of these is not given equal weight by policy-makers, but most of these are given at least some consideration in virtually every discussion of cost recovery and performance incentives. Many of these objectives apply to broader regulatory issues as well. Here the focus is solely on the objectives as they might apply to design of cost recovery and incentive mechanisms intended to serve the overarching objective stated above; that is whether the treatment of these objectives leads to a policy that effectively incents substantial cost-effective savings. A cost recovery and incentives policy that satisfies each of the design objectives described below, but which does not stimulate utility investment in energy efficiency, would not serve the overarching objective.

Strike an Appropriate Balance of Risk/Reward Between Utilities/Customers

The principal trade-off is between lowering utility risk/enhancing utility returns on the one hand and the magnitude of consumer benefits on the other. Mechanisms that reduce utility risk by, for example, providing timely recovery of lost margins and providing performance incentives, reduce consumer benefit, since consumers will pay for recovery and incentives through rates.[1] However, if the mechanisms are well-designed and implemented, customer benefits will be large enough that sharing some of this benefit as a way to reduce utility risk and strengthen institutional commitment will leave all parties better off than had no investment been made.

Promote Stabilization of Customer Rates and Bills

This objective is common to many regulatory policies and is relevant to energy efficiency cost recovery and incentives policy primarily with respect to recovery of lost margins. The ultimate objective served by a cost recovery and incentives policy implies an overall reduction in the long run costs to serve load, which equate to the total amount paid by customers over time. Therefore, while it is prudent to explore policy designs that, among available options, minimize potential rate volatility, the pursuit of rate stability should be balanced against the broader interest of total customer bill reductions. In fact, there are cases (Questar Gas in Utah, for example) where energy efficiency programs produce benefits for all customers (programs pass the so-called No-Losers test of cost-effectiveness) through reductions in commodity costs (Personal communication with Barry McKay, Questar Gas, July 9, 2007).

Program costs and performance incentives are relatively stable and predictable, or at least subject to caps. Lost margins can grow rapidly, and recovery can have a noticeable impact on customer rates. Decoupling mechanisms can be designed to mitigate this problem through the adoption of annual caps, but there have been isolated cases in which the true-ups have become so large due to factors independent of energy efficiency investment that regulators have balked at allowing full recovery.[2] Therefore, consideration of this objective is important for customers and utilities, as erratic and substantial energy efficiency cost swings can imperil full recovery and increase the risk of efficiency investments for utilities.

Stabilize Utility Revenues

This objective is a companion to stabilization of rates. Aggressive energy efficiency programs will impact utility revenues and full recovery of fixed costs. However, even if cost recovery policy covers program costs, lost margins, and performance incentives, how this recovery takes place can affect the pattern of earnings. Large episodic jumps in earnings (for example, produced by a decision to allow recovery of accrued lost margins in a lump sum), while better than non-recovery, cloud the financial community's ability to discern the true financial performance of the company, and creates the perception of risk that such adjustments might or might not happen again. PG&E views the ability of its decoupling mechanism to smooth earnings as a very important risk mitigation tool (personal communication with Roland Risser, PG&E).

Administrative Simplicity and Managing Regulatory Costs

Simplicity requires that any/all mechanisms be transparent with respect to both calculation of recoverable amounts and overall impact on utility earnings. This, in turn, supports minimizing regulatory costs. Given the workload facing regulatory commissions, adoption of cost recovery and incentive mechanisms that require frequent and complex regulatory review will create a latent barrier to effective implementation of the mechanisms. Every mechanism will impose some incremental cost on all parties, since some regulatory responsibilities are inevitable. The objective, therefore, is to structure mechanisms with several attributes that can establish at least a consistent and more formulaic process.

The mechanism should be supported by prior regulatory review of the proposed efficiency investment plan, and at least general approval of the contours of the plan and budget. In the alternative, policy-makers can establish clear rules prescribing what is considered acceptable/necessary as part of an investment plan, including cost caps. This will reduce the amount of time required for post-implementation review, as the prudence of the investment decision and the reasonableness of costs will have been established.

Use of tariff riders with periodic true-up allows for more clear segregation of investment costs and adjustment for over/under-recovery than simply including costs in a general rate case. However, in some states, the periodic treatment of energy efficiency program costs, fixed cost recovery, and incentives outside of a general rate case could be prohibited as single-issue ratemaking.[3]

Because certain mechanisms require evaluation and verification of program savings as a condition for recovery, very clear specification of the evaluation standards at the front end of the process is important. Millions of dollars are at stake in such evaluations, and failure to prescribe these standards early in the process almost guarantees that evaluation methods will be contested in cost recovery proceedings.

3.2 The Design Context

The need to design mechanisms that match the often unique circumstances of individual jurisdictions is clear, but what are the variables that determine the context for cost recovery and incentive design? The following table identifies and describes several variables often cited as important influences.

Table 3-1. Cost Recovery and Incentive Design Considerations

Variable	Implication
Related to Industry Structure	
Differences between gas and electric utility policy and operating environments	Wide variety of embedded implications. Gas utility cost structures create greater sensitivity to sales variability and recovery of fixed costs. In addition, as an industry, gas utilities face declining demand per customer.
Differences between investor-, publicly, and cooperatively owned utilities	Significant differences in financing structures. Municipal and cooperative ownership structures might provide greater ratemaking flexibility. Shareholder incentives are not relevant to publicly and cooperatively owned utilities, although management incentives might be.
Differences between bundled and unbundled utilities	Unbundled electric utilities have cost structures with some similarities to gas utilities; may be more susceptible to sales variability and fixed-cost recovery.

Variable	Implication
Presence of organized wholesale markets	Organized markets may provide an opportunity for utilities to resell "saved" megawatt-hours and megawatts to offset under-recovery of fixed costs.
Related to Regulatory Structure and Process	
Utility cost recovery and ratemaking statutes and rules	Determines permissible types of mechanisms. Prohibitions on single-issue ratemaking could preclude approval of recovery outside of general rate cases. Accounting rules could affect use of balancing and deferred/escrow accounts. Use of deferred accounts creates regulatory assets that are disfavored by Wall Street.
Related legislative mandates such as DSM program funding levels or inclusion of DSM in portfolio standards	Can eliminate decisional prudence issues/reduce utility program cost recovery risk. Does not address fixed-cost recovery or performance incentive issues.
Frequency of rate cases and the presence of automatic rate adjustment mechanisms	Frequent rate cases reduce the need for specific fixed-cost recovery mechanism, but do not address utility incentives to promote sales growth or disincentives to promote customer energy efficiency. Utility and regulator costs increase with frequency.
Type of test year	Type of test year (historic or future) is relevant mostly in cases in which energy efficiency cost recovery takes place exclusively within a rate case. Test year costs typically must be known, which can pose a problem for energy efficiency programs that are expected to ramp-up significantly. This applies particularly to the initiation or significant ramp-up of energy efficiency programs combined with a historic test year.
Performance-based ratemaking elements	Initiating an energy efficiency investment program within the context of an existing performance-based ratemaking (PBR) structure can be complicated, requiring both adjustments in so-called "Z factors"[4] and performance metrics. However, revenue-cap PBR can be consistent with decoupling.
Rate structure	The larger the share of fixed costs allocated to fixed charges, the lower the sensitivity of fixed-cost recovery to sales reductions. Price cap systems pose particular issues, since costs incurred for programs implemented subsequent to the cap but prior to its expiration must be carried as regulatory assets with all of the associated implications for the financial evaluation of the utility and the ultimate change in prices once the cap is lifted.
Regulatory commission/governing board resources	Resource-constrained commissions/governing boards may prefer simpler, self-adjusting mechanisms.

Variable	Implication
Related to the Operating Environment	
Sales/peak growth and urgency of projected reserve margin shortfalls	Rapid growth may imply growing capacity needs, which will boost avoided costs. Higher avoided costs create a larger potential net benefit for efficiency programs and higher potential utility performance incentive. Growth rate does not affect fixed-cost recovery if the rate has been factored into the calculation of prices.
Volatility in load growth	Unexpected acceleration or slowing of load growth can have a major impact on fixed-cost recovery, an impact that can vary by type of utility. Higher than expected growth can lessen the impact of energy efficiency on fixed cost recovery, while slower growth exacerbates it. On the other hand, if the cost to add a new customer exceeds the embedded cost, higher than expected growth can adversely impact utility finances.
Utility cost structure	Utilities with higher fixed/variable cost structures are more susceptible to the fixed-cost recovery problem.
Structure of the DSM portfolio	Portfolios more heavily weighted toward electric demand response will result in less significant lost margin recovery issues, thus reducing the need for a specific mechanism to address. Moreover, a portfolio weighted toward demand response typically will not offer the same environmental benefits.

3.3 Notes

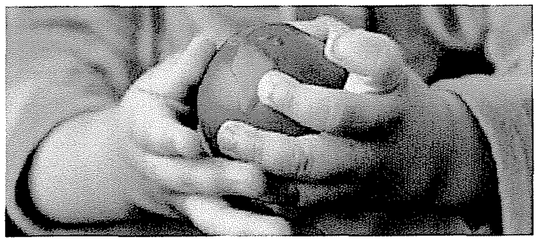
1 A related concern raised by skeptics of performance incentives is that by providing an incentive to utilities to deliver successful energy efficiency programs, customers might pay more than they otherwise should or would have to achieve the same result if another party delivered the programs, or if the utilities were simply directed to acquire a certain amount of energy savings. Of course, the counter-argument is that in some cases, the level of savings actually achieved by a utility (savings in excess of a goal, for example) are motivated by the opportunity to earn an incentive. In addition, certain third-party models include the opportunity for the administering entity to earn performance incentives.

2 See the discussion of the Maine decoupling mechanism in the National Action Plan for Energy Efficiency, July 2006, Chapter 2, pages 2-5. The examples of this issue are isolated, emerging in early decoupling programs in the electric utility industry. The negative impacts were exacerbated by accounting treatments that deferred recovery of the revenues in the balancing accounts.

3 Single issue ratemaking allows for a cost change in a single item in a utility's cost of service to flow through to consumer rates. A prohibition on single-issue ratemaking occurs because, among the multitude of utility cost items, there will be increases and decreases, and many states find it inappropriate to base a rate change on the movement of any single cost item in isolation. In some states, a fuel adjustment clause is an exception to this rule, justified because the impacts of changes in fuel costs on the total cost of service is high. States that employ an energy efficiency rider justify this exception as a function of the policy importance of energy efficiency and as an important element in creating a stable energy efficiency funding environment.

4 Z factors are factors affecting the price of service over which the utility has no control. PBR programs typically allow rate cap adjustments to accommodate changes in these factors.

4: Program Cost Recovery



This chapter provides a practical overview of alternative cost recovery mechanisms and presents their pros and cons. Detailed case studies are provided for each mechanism.

Administration and implementation of energy efficiency programs by utilities or third-party administrators involves the annual expenditure of several million dollars to several hundred million dollars, depending on the jurisdiction. The most basic requirement for elimination of disincentives to customer-funded energy efficiency is establishing a fair, expeditious process for recovery of these costs, which include participant incentives and implementation, administration, and evaluation costs. Failure to recover such costs directly and negatively affects a utility's cash flow, net operating income, and earnings.

Utilities incur two types of costs in the provision of service. Capital costs are associated with the plant and equipment associated with the production and delivery of energy. Expenses typically are the costs of service that are not directly associated with physical plant or other hard assets.[1] The amount of revenue that a utility must earn over a given period to be financially viable must cover the sum of expenses over that period plus the financial cost associated with the utility's physical assets. In simple terms, a utility revenue requirement is equivalent to the cost of owning and operating a home, including the mortgage payment and ongoing expenses. The costs associated with utility energy efficiency programs must be recovered either as expenses or as capital items.

The predominant approach to recovery of program costs is through some type of periodic rate adjustment established and monitored by state utility regulatory commissions or the governing entities for publicly or cooperatively owned utilities. These regulatory mechanisms can take a variety of forms including recovery as expenses in traditional rate cases, recovery as expenses through surcharges or riders that can be adjusted periodically outside of a formal rate case, or recovery via capitalization and amortization. Variations exist within these broad forms of cost recovery as well, through the use of balancing accounts, escrow accounts, test years, and so forth.

The approach applied in any given jurisdiction will often be the product of a variety of local factors such as the frequency of rate cases, the specific forms of cost accounting allowed in a state, the amount and timing of expenditures, and the types of programs being implemented. States will also differ in how costs are distributed across and recovered from different customer classes. Some states, for example, allow large customers to opt-out of efficiency programs administered by utilities,[2] and some states require that costs be recovered only from the classes of customers directly benefiting from specific programs. These variations preclude a single best approach. However, for those utilities and states considering implementation of energy efficiency programs, the variety of approaches offers a variety of options to consider.

4.1 Expensing of Energy Efficiency Program Costs

Most energy efficiency program costs are recovered through "expensing." In the simplest case, if a utility spends $1.00 to fund an energy efficiency program, that $1.00 is passed directly to customers as part of the utility's cost of service. While in principle, the expensing of energy efficiency program costs is straightforward, utilities and state regulatory commissions have employed a wide variety of specific accounting treatments and actual recovery mechanisms to enable recovery of program expenses. This section provides an overview of several of the more common approaches.

4.1.1 Rate Case Recovery

The most straightforward approach to recovery of program costs as expenses involves recovery in base rates as an element of the utility revenue requirement. Energy efficiency program costs are estimated for the relevant period, added to the utility's revenue requirement, and recovered through customer rates that were set based on this revenue requirement and estimated sales. Rate cases typically involve an estimate of known future costs, given that the rates that emerge from the case are applied going forward. For example, a utility and its commission might conduct a rate case in 2007 to establish the rates that will apply beginning in 2008. Therefore, the utility will estimate (and be seeking approval to incur) the costs associated with the energy efficiency program in 2008 and annually thereafter. The approved level of energy efficiency spending will be included in the allowed revenue requirement, and the rates taking effect in 2008 should include an amount that will recover the utility's budgeted program costs over the course of the year based on the level of annual sales estimated in the rate case. Although actual program expenses rarely match the amount of revenue collected for those programs in real-time, in principle, program expenses incurred will match revenue received by the end of the year. This approach works best when annual energy efficiency expenditures are constant on average.

4.1.2 Balancing Accounts with Periodic True-Up

Practice rarely matches principle, however, particularly with respect to energy efficiency program costs. The estimates of program costs used as the basis for setting rates are based in large part on assumed customer participation in the efficiency programs. However, participation is difficult to predict at a level of precision that ensures that annual expenditures will match annual revenue, especially in the early years of programs. Under-recovery of expenses occurs if participation in programs exceeds estimates and actual program costs rise. Regulatory commissions and utilities frequently have implemented various types of balancing mechanisms to ensure that customers do not pay for costs never incurred, and that utilities are not penalized because participation and program costs exceeded estimates. Such approaches also enable utilities to more flexibly ramp program activity (and associated spending) up or down. These mechanisms also often include some type of periodic prudence review to ensure that costs incurred in excess of those estimated in the rate case were prudently incurred.

The mechanics of a balancing account can work in a number of ways. Balances can simply be carried (typically with an associated carrying charge) until the next rate case, at which point they are "trued-up."[3] A positive balance could be used to reduce the level of expenses authorized for recovery in the future period, and a negative balance could be added in full to the authorized revenues for the future period or could be amortized. Alternatively, the balances can be self-adjusting by using a surcharge or tariff rider (discussed below), and some states allow annual true-up outside of general rate case proceedings.[4]

4.1.3 Pros and Cons

The following table describes general pros and cons associated with the expensing of program costs.

Table 4-1. Pros and Cons of Expensing

Pros

- Expensing treatment is generally consistent with standard utility cost accounting and recovery rules.
- Avoids the creation of potentially large regulatory assets and associated carrying costs.
- Provides more-or-less immediate recovery of costs and reduces recovery risk.
- The use of balancing mechanisms outside of a general rate case ensures more timely recovery when efficiency program costs are variable and prevents significant over- or under-recovery from being carried forward to the next rate case.

Cons

- A combination of infrequent rate cases and escalating expenditures can lead to under-recovery absent a balancing mechanism.
- Can be viewed as single-issue ratemaking.
- If annual energy efficiency expenditures are large, lump sum recovery can have a measurable short-term impact on rates.
- Some have argued that expensing creates unequal treatment between the supply-side investments (which are rate-based) and the efficiency investments that are intended to substitute for new supply.

4.1.4 Case Study: Arizona Public Service Company (APS)

In June 2003, APS filed an application for a rate increase and a settlement agreement was signed between APS and the involved parties in August 2004. The settlement addresses DSM and cost recovery, allowing $10 million each year in base rates for eligible expenses, as well as an adjustment mechanism for program expenses beyond $10 million.

- The settlement agreement embodied in Order No. 67744 issued in April of 2005, under Docket No. E-01345A-03-0437[5] includes the following provisions:

- Included in APS' total test year settlement base rate revenue requirement is an annual $10 million base rate DSM allowance for the costs of approved "eligible DSM-related items," defined as the planning, implementation, and evaluation of programs that reduce the use of electricity by means of energy efficiency products, services, or practices. Performance incentives are included as an allowable expense.
- In addition to expending the annual $10 million base rate allowance, APS is obligated to spend, on average, at least another $6 million annually on approved eligible DSM-related items. These additional amounts are to be recovered by means of a DSM adjustment mechanism.
- All DSM programs must be pre-approved before APS may include their costs in any determination of total DSM costs incurred.
- The adjustment mechanism uses an adjustor rate, initially set at zero, which is to be reset on March 1, 2006, and thereafter on March 1 of each subsequent year. The adjustor is used only to recover costs in arrears. APS is required to file its proposal for spending in excess of $10 million prior to the March 1 adjustment. The per-kilowatt-hour charge for the year will be calculated by dividing the account balance by the number of kilowatt-hours used by customers in the previous calendar year.
- General Service customers that are demand-billed will pay a per-kilowatt charge instead of a per-kilowatt-hour charge. The account balance allocated to the General Service class is divided by the kilowatt billing determinant for the demand-billed customers in that class to determine the per-kilowatt DSM adjustor charge. The DSM adjustor applies to all customers taking delivery from the company, including direct access customers.

4.1.5 Case Study: Iowa Energy Efficiency Cost Recovery Surcharge

Until 1997, electric energy efficiency program costs were tracked in deferred accounts with recovery in a rate case via capitalization and amortization. Since then investor-owned utilities in Iowa, pursuant to Iowa Code 2001, Section 476.6,[6] recover energy efficiency program-related costs through an automatic rate pass-through reconciled annually to prevent over- or under-recovery (i.e., costs are expensed and recovered concurrently). Program costs are allocated within the rate classes to which the programs are directed, although certain program costs, such as those associated with low income and research and development programs, are allocated to all customers. The cost recovery surcharge is recalculated annually based on historical collections and expenses and planned budgets. The energy efficiency costs recovered from customers during the previous period are compared to those that were allowed to be recovered at the time of the prior adjustment. Any over- or under-collection, any ongoing costs, and any change in forecast sales, are used to adjust the current energy efficiency cost recovery factors. The statute requires that each utility file, by March 1 of each year, the energy efficiency costs proposed to be recovered in rates for the 12-month recovery period. This period begins at the start of the first utility billing month at least 30 days following Iowa Utility Board approval.

199 Iowa Administrative Code Chapter 35[7] provides the detailed cost recovery mechanism in place in Iowa. These details are summarized in Appendix D.

4.1.6 Case Study: Florida Electric-Rider Surcharge

The Florida Energy Efficiency and Conservation Act (FEECA) was enacted in 1980 and required the Florida Commission to adopt rules requiring electric utilities to implement cost-effective conservation and DSM programs. Florida Administrative Code Rules 25-17.001 through 25-17.015 require all electric utilities to implement cost-effective DSM programs. In June 1993, the Commission revised the existing rules and required the establishment of numeric goals for summer and winter demand and annual energy sales reductions.

In order to obtain cost recovery, utilities are required to provide a cost-effectiveness analysis of each program using the ratepayer impact measure, total resource cost, and participant cost tests.

Investor-owned electric utilities are allowed to recover prudent and reasonable commission-approved expenses through the Energy Conservation Cost Recovery (ECCR) clause. The commission conducts ECCR proceedings during November of each year. The Commission determines an ECCR factor to be applied to the energy portion of each customer's bill during the next calendar year. These factors are set based on each utility's estimated conservation costs for the next calendar year, along with a true-up for any actual conservation cost under- or over-recovery for the previous year (Florida Public Service Commission, 2007).

The procedure for conservation cost recovery is described by Florida Administrative Code Rule 25-17.015(1);[8] details are included in Appendix D. The following table shows the current cost recovery factors.

Table 4-2. Current Cost Recovery Factors in Florida

	Residential Conservation Cost Recovery Factor (cents per kWh)	Typical Residential Monthly Bill Impact (based on 1,000 kWh)
FPL	0.169	$1.69
FPUC	0.060	$0.60
Gulf	0.088	$0.88
Progress	0.169	$1.96
TECO	0.073	$0.73

Florida Power and Light's (FPL's) recent cost recovery filing provides some insight into the nature of the adjustment process:

> FPL projects total conservation program costs, net of all program revenues, of $175,303,326 for the period January 2007 through December 2007. The net true-up is an over recovery of $4,662,647, which includes the final conservation true-up over recovery for January 2005, through December 2005, of $5,849,271 that was reported in FPL's Schedule CT-1, filed May 1, 2006. Decreasing the projected costs

of $175,303,326 by the net true-up over-recovery of $4,662,647 results in a total of $170,640,679 of conservation costs (plus applicable taxes) to be recovered during the January 2007, through December 2007, period. Total recoverable conservation costs and applicable taxes, net of program revenues and reflecting any applicable over- or under-recoveries are $170,705,441, and the conservation cost recovery factors for which FPL seeks approval are designed to recover this level of costs and taxes.

4.2 Capitalization and Amortization of Energy Efficiency Program Costs

Capitalization as a cost recovery method is typically reserved for the costs of physical assets such as generating plant and transmission lines. However, some states allow the costs of energy efficiency and demand-response programs to be treated as capital items, even though the utility is not acquiring any physical asset. In the case of an investor-owned utility, such capital items are included in the utility's rate base. The utility is allowed to earn a return on this capital, and the investment is depreciated over time, with the depreciation charged as an expense. Depending on precisely how a capitalization mechanism is structured, it can serve as a strict cost-recovery tool or as a utility performance incentive mechanism as well. A principle argument made in favor of capitalizing energy efficiency program costs is that this treatment places demand-and supply-side expenditures on an equal financial footing.[9,10]

Capitalization[11] currently is not a common approach to energy efficiency program cost recovery, although during the peak of the last major cycle of utility energy efficiency investment during the late 1980s and early 1990s many states allowed or required capitalization.[12]

Capitalization of energy efficiency costs as a cost recovery mechanism first appeared in the Pacific Northwest (Reid, 1988). Oregon and Idaho were the first two states to allow capitalization of certain selected costs in the early 1980s. Washington soon followed with statutory authority for ratebasing that included authorization for a higher return on energy efficiency investments. Puget Power[13] in Washington was allowed to ratebase all of its energy efficiency-related costs using a 10-year recovery period with no carrying charges applied to the costs incurred between rate cases. Montana followed Washington in 1983 and adopted a similar mechanism. In 1986, Wisconsin switched from expensing the conservation expenditures to capitalization and allowed a large amount of direct investment to be capitalized with a 10-year amortization period.

With a very few exceptions, capitalization is no longer the method of choice for energy efficiency cost recovery in these states. The decline in the popularity of this approach can be attributed to a variety of factors, including the general decline in utility energy efficiency investment. However, in several states capitalization was abandoned, in part because the total costs associated with recovery (given the cost of the return on investment) were rising rapidly.

4.2.1 The Mechanics of Capitalization

As a simplified example, suppose that a utility spends $1 million in each of five years for its energy efficiency programs, and it is allowed to capitalize and amortize these investments over a 10-year recovery period uniformly. The following table illustrates the yearly change in revenue requirements, assuming a 10 percent rate of return on the unrecovered balance.

Table 4-3. Illustration of Energy Efficiency Investment Capitalization

End-of-year	Annual Energy-Efficiency Expenditure	Cumulative Energy-Efficiency Expenditure	Depreciation	Unamortized Balance	Return on Unrecovered Investment	Incremental Revenue Requirements
1	1,000,000	1,000,000	$100,000	$900,000	$90,000	$190,000
2	1,000,000	2,000,000	$200,000	$1,700,000	$170,000	$370,000
3	1,000,000	3,000,000	$300,000	$2,400,000	$240,000	$540,000
4	1,000,000	4,000,000	$400,000	$3,000,000	$300,000	$700,000
5	1,000,000	5,000,000	$500,000	$3,500,000	$350,000	$850,000
6			$500,000	$3,000,000	$300,000	$800,000
7			$500,000	$2,500,000	$250,000	$750,000
8			$500,000	$2,000,000	$200,000	$700,000
9			$500,000	$1,500,000	$150,000	$650,000
10			$500,000	$1,000,000	$100,000	$600,000
11			$400,000	$600,000	$60,000	$460,000
12			$300,000	$300,000	$30,000	$330,000
13			$200,000	$100,000	$10,000	$210,000
14			$100,000	$0	$0	$100,000
15/Total	5,000,000		$5,000,000		$2,250,000	$7,250,000

By the end of the 15-year amortization period, the total amount collected by the utility through rates is $7,250,000. Just as the total cost of purchasing a home will be lower with a shorter mortgage, shorter amortization periods yield a lower total cost for recovery of the energy efficiency program expenditures. Similarly, although the total amount recovered is almost 50 percent higher in this case than the direct cost of the energy efficiency program, the $2,250,000 represents a legitimate cost to the utility which comes from the need to carry an unrecovered balance on its books. Conceptually, a utility will be indifferent to immediate recovery of program costs as an expense and capitalization, as the added cost of capitalization should be equal to the cost to the utility of effectively lending the $5 million to customers. However, in the cases of those states that have allowed utilities to earn a return on energy efficiency investments that exceeds their weighted cost of capital, this added return constitutes an incentive for investment in energy efficiency that goes beyond that provided for traditional capital investments.

4.2.2 Issues

The length of time over which an energy efficiency investment is amortized (essentially the rate of depreciation), and the capital recovery rate or rate-of-return on the unamortized balance of the investment, both affect the total cost to customers of the utility.

Amortization and Depreciation

When an expenditure is capitalized, the recovery of this expenditure is spread over several years, with predetermined amounts recovered in rates each year during the recovery or amortization period. The depreciation or amortization rate is the fraction of unrecovered cost that is recovered each year. Tax law and regulation generally govern the specific rate used for different types of capital investments such as generating or distribution plant and equipment and other physical structures. However, since the costs of energy efficiency programs typically are not considered capital items, there is no universally accepted depreciation rate applied to energy efficiency program costs that are capitalized. An early study (Reid, 1988) of energy efficiency capitalization found that amortization programs for conservation expenditures ranged from three to 10 years. For example, Washington and Wisconsin allowed a 10-year recovery period for amortization. Massachusetts used the lifetime of the energy efficiency equipment for the recovery period.

Rate of Return[14]

Just as the interest rate on a home mortgage can greatly affect both the monthly payment and the total cost of the home, the rate of return allowed on the unamortized cost of an energy efficiency program can significantly affect the cost of that program to ratepayers. Rates-of-return for investor-owned utilities are set by state regulators based on the relative costs of debt and equity. In the case of publicly and cooperatively owned utilities, the return much more closely mirrors the cost of debt. The ROE, in turn, is based on an assessment of the financial returns that investors in that utility would expect to receive—an expectation that is influenced by the perceived riskiness of the investment. This riskiness is related directly to the perceived likelihood that a utility will, for some reason, not be able to earn enough money to pay off the investment.

Unless the level of energy efficiency program investment is significant relative to a utility's total unamortized capital investment, the relative riskiness of energy efficiency versus supply-side investments is not a major issue. However, if this investment is significant, the relative risk of an energy efficiency investment can become an issue for a variety of reasons, including:

- These resources are not backed by physical assets. While a utility actually owns gas distribution mains or generating plants, it does not own an efficient air conditioner that a customer installs through a utility program. If energy efficiency spending is accrued for future recovery, either by expensing or amortization, this accrual is considered as a "regulatory asset"—an asset created by regulatory policy that is not backed by an actual plant or equipment. Carrying substantial regulatory assets on the balance sheet can hurt a utility's financial rating.

- The investment becomes more susceptible to disallowance. Recovery of a capital investment typically is allowed only for investments deemed prudent and used-and-useful. Because energy efficiency programs are based on customer behavior, and because that behavior is difficult to predict, it is possible that the investment being recovered does not actually produce its intended benefit. This result could lead regulators to conclude that the investment was not prudent or used-and-useful. This risk owes more to the fact that energy efficiency program effectiveness is subject to ex post evaluation. As program design and implementation experience grows, program realization rates (the ratio of actual to expected savings) increases, and this risk diminishes. It is not clear that this risk is any different with respect to its ultimate effect than the risks associated with the construction and operation of a utility plant.
- Potential uncertainty arising from policy changes that govern energy efficiency incentive mechanisms heightens the risk. Although both supply- and demand-side resources are subject to policy risk, the modularity and short lead-times associated with demand-side resources (which is a distinct benefit from a resource planning perspective) also create more opportunities to revisit the policies governing energy efficiency expenditure and cost recovery. The fact that energy efficiency program costs are regulatory assets in theory, means that the regulatory policy underlying those assets can change with changes in the regulatory environment. The pressure to modify policies governing recovery of program costs has increased historically as the size of these assets has grown with increases in program funding.

4.2.3 Pros and Cons

Based on experience to date, capitalization and amortization carries pros and cons as illustrated in the table on the next page.

Table 4-4. Pros and Cons of Capitalization and Amortization

Pros

- Places energy efficiency investments on more of an equal footing with supply-side investment with respect to cost recovery
- Capitalization can help make up for the decline in utility generation and transmission and distribution assets expected to occur, as energy efficiency defers the need for new supply-side investment.
- As part of this equalization, enables the utility to earn a financial return on efficiency investments.
- Smoothes the rate impacts of large swings in annual energy efficiency spending.

Cons

- Treats what is arguably an expense as a capital item.
- Creates a regulatory asset that can grow substantially over time; because this asset is not tangible or owned by utility, it tends to be viewed as more risky by the financial community.
- Delays full recovery and boosts recovery risk.
- To the extent that the return on the energy efficiency program investment is intended to provide a financial incentive for the utility, this incentive is not tied to program performance.
- Raises the total dollar cost of the efficiency programs.

4.2.4 Case Study: Nevada Electric Capitalization with ROE Bonus

Nevada is the only state currently that allows recovery of energy efficiency program costs using capitalization *as well as* a bonus return on those costs. Development and administration of energy efficiency programs by Nevada's regulated electric utilities takes place within the context of an integrated resource planning process combined with a resource portfolio standard that allows energy efficiency programs to fulfill up to 25 percent of the utilities' portfolio requirements. Over the past several years spending on energy efficiency programs has risen substantially, both as a response to rapid growth in electricity demand and as Nevada Power and Sierra Pacific Power have attempted to maximize the contribution of energy efficiency to portfolio requirements as those requirements grow.

All prudently incurred costs associated with energy efficiency programs are recoverable pursuant to the Nevada Administrative Code 704.9523. A utility may seek to recover any costs associated with approved programs for conservation and DSM, including labor, overhead, materials, incentives paid to customer, advertising, and program monitoring and evaluation.

Mechanically, the Nevada mechanism works as follows for those approved programs not already included in a utility's rate base:

- The utility tracks all program costs monthly in a separate account.
- A carrying cost equal to 1/12 of the utility's annual allowed rate of return is applied to the balance in the account.
- At the time of the next rate case, the balance in the account (including program costs and carrying costs) is cleared from the tracking account and moved into the utility's rate base.
- The commission sets an appropriate amortization period for the account balance based on its determination of the life of the investment.
- The utility applies a rate of return to the unamortized balances equal to the authorized rate of return plus 5 percent (for example a 10.0 percent return becomes 10.5 percent).

Nevada's current cost recovery/incentive structure has been in place since 2001. However, with the recent rapid rise in utility energy efficiency program spending, concerns also have arisen with respect to the structure of the mechanism and its effect on the utilities' investment incentives. These concerns prompted the Nevada Public Service Commission to open an investigatory docket in late 2006. In its Revised Order in Docket Nos. 06-0651 and 07-07010 on January 30, 2007, the commission wrote that:

> [We] believe that appropriate incentives for utility DSM programs are necessary. The exact nature and form of incentives that should be offered for such programs involve a number of factors, including the regulatory and statutory environment. The current incentives for DSM were implemented in 2001 when the companies had few, if any, incentives to implement DSM programs. The enactment of A.B. 3 changed both the regulatory and statutory context. Utilities now have incentives to implement DSM to meet portions of their respective renewable portfolio standard requirements. Nevada Power Company's expenditures will increase almost four times compared to pre A.B. 3 during this action plan. Given these changes, it is now time to reexamine the mandatory package of incentives provided to DSM programs. This includes the types and categories of costs eligible for expense treatment, as well as prescribed incentives. The commission therefore directs its secretary to open an investigation and rulemaking into the appropriateness of DSM cost recovery mechanisms and incentives.

In early 2007, the commission asked all interested parties to comment on four specific issues, as identified below:

- What are the public policy objectives of an incentive structure? i.e., Should only the most cost-effective programs be incented? Should only the most strategic programs be incented?
- Does the current incentive structure provide the appropriate incentives to fulfill each public policy objective?
- Are there alternative incentive structures that the commission should consider? If so, what are these incentives and how would each further the goals identified above?
- How should the current incentive structure be redesigned? i.e., what expenses should be included in the incentive mechanism? What should be the basis for determining incentives?

Commission staff has argued that the underlying rationale for utility energy efficiency investments is found in the integrated resource planning process. Staff noted that utilities should be inclined to pursue those programs that contribute to the least-cost resource mix. The addition of the resource portfolio requirement and the ability to meet up to 25 percent of that requirement provides further incentive to pursue energy efficiency investment. At the same time, staff argued that the current cost recovery mechanism, with the addition of the five percentage point rate of return bonus, provided no incentive for effective program performance and in fact, simply encouraged additional spending with no consideration for the implementation outcome—an argument echoed by the Attorney General's Bureau of Consumer Protection. Staff recommended that the ideal solution is to tie incentives to program performance and to share program net benefits with ratepayers.

Nevada Power Company and Sierra Pacific Power Company have endorsed the existing mechanism as providing appropriate incentives to fulfill the public policy objective of achieving a net benefit for customers while providing a stable and motivating incentive for the utility. According to the companies, the current incentive scheme with the bonus rate of return recognizes the increased risks associated with DSM investments compared to the supply-side investments, and they argue that changing the existing incentive structure will create uncertainty and therefore, increase the perceived risk associated with energy efficiency investments. They further argue that the integrated resource plan review process ensures that program budgets are given detailed review.

4.3 Notes

1 Depreciation of capital equipment is, however, treated as an expense.

2 An "opt-out" allows a customer, typically a large customer, to elect to not participate in a utility program and to avoid paying associated program costs. Some states do not allow opt-outs, but will allow large customers to spend the monies that otherwise would be collected from them by utilities for efficiency projects in their own facilities. This often is called "self-direction."

3 Wisconsin investor-owned utilities use "escrow accounting" as a form of a balancing account. Should the public service commission authorize a utility to incur specific program costs during a period between rate cases, these costs are recorded in an escrow account. Carrying charges are applied to the balance. The balance of the escrow account is cleared into the revenue requirement at the time of the next rate case (typically every two years).

4 As discussed elsewhere in this paper, addressing recovery of program costs as a separate matter apart from all other utility cost changes could be considered single-issue ratemaking which can be prohibited.

5 Order No. 67744, *In the Matter of the Application of the Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop such Return, and for Approval of Purchased Power Contract,* Docket No. E-01345-A-03-0437, accessed at http://images.edocket.azcc.gov/docketpdf/0000018816.pdf.

6 Iowa Code 2001: Section 476.6, accessed at http://www.legis.state.ia.us/IACODE/2001/476/6.html.

7 199 Iowa Administrative Code Chapter 35, accessed at http://www.legis.state.ia.us/Rules/Current/iac/199iac/19935/19935.pdf.

8 Florida Administrative Code Rule 25-17.015(1), accessed at http://www.flrules.org/gateway/RuleNo.asp?ID=25-17.015.

9 Some have argued that capitalization and amortization of energy efficiency program costs provides an incentive to utilities to invest in energy efficiency without regard to the performance of the programs. See the Nevada case study below for a broader treatment of this issue.

10 From a narrow theoretical perspective, there should be no significant financial difference between expensing and capitalization. The return on capital is intended to compensate a utility for the cost of money used to fund an activity. For investor-owned utilities, this compensation includes payment to equity investors. However, if program expenses are immediately expensed—that is, if the utility can immediately recover each dollar it expends on a program—the utility does not need to "advance" capital to fund the programs, and therefore, there is no cost incurred by the utility.

11 We use the generic term "capitalization" as opposed to "ratebasing," since, in some states, energy efficiency program costs technically are not included in a utility's rate base but are treated in a similar fashion via capitalization.

12 The following states either have used in the past or continue to use some form of capitalization of energy efficiency costs: Oregon, Idaho, Washington, Montana, Texas, Wisconsin, Nevada, Oklahoma, Connecticut, Maine, Massachusetts, Vermont, and Iowa. With the exception of Nevada, most of these states are no longer using capitalization, though it remains an option. See Reid, M. (1988). *Ratebasing of Utility Conservation and Load Management Programs. The Alliance to Save Energy.*

13 Puget Power is now known as Puget Sound Energy.

14 "Rate of return" is used in this context to refer to the rate applied to an unamortized balance that is used to represent the cost of money to the utility. In the case of investor-owned utilities, this rate is usually a weighted average of the interest rate on debt and the allowed return on equity.

5: Lost Margin Recovery

This chapter provides a practical overview of alternative mechanisms to address the recovery of lost margins and presents their pros and cons. Detailed case studies are provided for each mechanism.

Chapter 2 of the Action Plan provides a concise explanation of the throughput incentive and an excellent summary of options to mitigate the incentive. This incentive has been identified by many as the primary barrier to aggressive utility investment in energy efficiency. Policy expectations that utilities aggressively pursue the implementation of energy efficiency programs create a conflict of interest for utilities in that they cannot fulfill their obligations to their shareholders while simultaneously encouraging energy efficiency efforts of their customers, which will reduce their sales and margins in the presence of the throughput incentive.

Any approach aiming to eliminate, or at least neutralize, the impact of the throughput incentive on effective implementation of energy efficiency programs must address the issue of lost margins due to successful energy efficiency programs. Two major cost recovery approaches have been tried since the 1980s with this objective in mind; *decoupling* and *lost revenue* recovery.[1] A third approach, known generically as *straight fixed-variable* (SFV) ratemaking, conceptually provides a solution to the problem by allocating most or all fixed costs to a fixed (non-volumetric) charge. Under such a rate design, reductions in the volume of sales do not affect recovery of fixed costs. While conceptually appealing, this approach carries with it complex implementation issues associated with the transition from a structure that recovers fixed costs via volumetric charges to a SFV structure. It also can reduce the financial incentive for end-users to pursue energy efficiency investments by reducing the value that consumers realize by reducing the volume of consumption—an issue more likely to impact electricity consumers than gas customers, since commodity cost represents a larger share of a consumer's total gas bill. While it has seen application in the natural gas industry, SFV ratemaking is uncommon in the electric industry (see American Gas Association, 2007).

5.1 Decoupling

In recent years, decoupling has re-emerged as an approach to address the margin recovery issue facing utilities implementing substantial energy efficiency program investments. Decoupling can be defined generally as a separation of revenues and profits from the volume of energy sold and, in theory, makes a utility indifferent to sales fluctuations. Mechanically, decoupling trues-up revenues via a price adjustment when actual sales are different than the projected or test year levels.

Decoupling mechanisms appear under various names including the following listed by the National Regulatory Research Institute (Costello, 2006): Conservation Margin Tracker; Conservation-Enabling Tariff; Conservation Tariff; Conservation Rider; Conservation and Usage Adjustment (CUA) Tariff; Conservation Tracker Allowance; Incentive Equalizer; Delivery Margin Normalization; Usage per Customer Tracker; Fixed Cost Recovery Mechanism; and Customer Utilization Tracker. Decoupling is often cited as a solution to the throughput issue raised by energy efficiency programs. It is also a mechanism that often is generally suggested as a way to smooth earnings in the face of sales volatility. Natural gas utilities have been among the strongest advocates of decoupling because of its ability to moderate the impacts of abnormal weather and declining usage per customer, in addition to its ability to mitigate the under-recovery of fixed costs caused by energy efficiency programs (see American Gas Association, 2006a).

A decoupling mechanism will sometimes include a balancing account in order to ensure the exact collection of the revenue requirement, although this approach typically is used only if there is an extended period between rate adjustments. If revenues collected deviate from allowed revenues, the difference is collected from or returned to customers through periodic adjustments or reconciliation mechanisms. If a successful energy efficiency program reduces sales, there will not be any loss in revenue resulting from these energy efficiency programs. If sales turn out to be higher than the projected, the excess revenue is returned to the ratepayer.

The term "decoupling" is used generically to represent a variety of methods for severing the link between revenue recovery and sales. These methods vary widely in scope, and it is rare that a mechanism fully decouples sales and revenues. Some approaches provide for limited true-ups in attempts to ensure that utilities continue to bear the risks for sales changes unrelated to energy efficiency programs. Some focus on preserving recovery of lost margins. This focus recognizes that a sales reduction will be accompanied by some cost reduction, and therefore, the total revenue requirement will be lower. Truing up total revenue would, in such cases, boost utility earnings.

There are two major forms of revenue decoupling—those linked to total revenue and those focused on revenue per customer: the revenue a utility is allowed to earn is capped in the former, and the revenue per customer is capped in the latter. The primary advantage of a revenue-per-customer model is that it recognizes the link between a utility's revenue requirement and its number of customers. For example, if a decoupling mechanism caps total revenue, and if the utility experiences a net increase in customers, all else being equal, the allowed level of revenue will fall short of the cost of serving the additional customers, leading to a drop in earnings. A revenue-per-customer mechanism allows total revenue to grow (or fall) as the number of customers and associated costs rise (fall).

The following simple example (constructed similarly to the example in Eto et al., 1994) illustrates the basic decoupling mechanism with a balancing account.

Table 5-1. Illustration of Revenue Decoupling

	Year	A Revenue Requirements	B Expected Sales (Therms)	C (A÷B) Price Set in the Rate Case (Therms)	D Allowed to Collect	E (D÷B) Actual Price ($/Therm)	F Actual Sales (Therms)	G (E×F) Actual Revenue	H (G–A) Changes Between Revenue Requirement and Actual Revenue	I (D–G) Balance Account
Rate Case 1	1	$100.00	1,000	0.100	$100.00	0.100	1,100	$110.00	$10.00	-$10.00
	2	$100.00	1,000	0.100	$90.00	0.090	990	$89.10	-$10.90	$0.90
Rate Case 2	3	$111.10	1,010	0.110	$112.00	0.111	1,010	$112.00	$0.90	$0.00

For year 1, the revenue requirement of $100 is authorized through the general rate case. Given the 1,000 therm projected sales, the price is determined to be 10 cents/therm. If actual sales are 1,100 therm, then at the rate of 0.1 $/therm, the actual realized revenue is $110. The utility places the $10 difference between the actual revenue and the allowed revenue in a balancing account. The next year, the utility needs to collect only $90 to reach the $100 authorized revenue and the price per therm is set at 9 cents. If the sales were indeed 1,000 therms, the utility would make $90, and with the $10 in the balancing account, it would exactly meet the authorized revenue. However, in this example, the sales are 990 therms, and utility revenue is $89.10 at 9 cents/therm. The utility needs to collect 90 cents from the ratepayers.

Suppose that the revenue requirement is reset to $111.10 at the projected sales level of 1,010 therms. The utility needs to collect the balance in the balancing account and its authorized revenue of $111.10, a total of $112. At the projected sales level of 1,010, the price needs to be set at 11.1 cents per therm to recover $112. Suppose that the utility's sales are actually equal to the projected sales of 1,010. The utility recovers exactly $112 and there is a zero balance left in the balancing account.

Under the revenue-per-customer cap approach, the actual revenues collected *per customer* are compared to the authorized revenues *per customer,* and the balancing account maintains the over- or under-earnings. The utility recovers additional revenue if the number of customers goes up and less revenue if the number declines. The rationale behind a revenue-per-customer cap is that customer growth (or decline) is a major determinant of a utility's revenue requirement. Capping revenue without adjustment for customer growth could place a serious financial constraint on the utility.

A simple example of the revenue cap-per-customer approach is illustrated on the next page.

Performance-Based Ratemaking and Decoupling

Performance-Based Ratemaking (PBR) is an alternative to traditional return on rate base regulation that attempts to forego frequent rate cases by allowing rates or revenues to fluctuate as a function of specified utility performance against a set of benchmarks. One form of PBR embodies a revenue cap mechanism that functions very much like a decoupling, wherein price is allowed to fluctuate as a way to true-up actual revenues to allowed revenues. The revenue-cap PBR mechanism can be more complex, incorporating a variety of specific adjustments to both price and revenue. In most cases, if a utility operates under revenue-cap PBR, sales and revenues are decoupled for purposes of energy efficiency investment, although specific adjustments may be required to allow prices to be adjusted for changes in actual program costs as well as changes in margins.

Table 5-2. Illustration of Revenue per Customer Decoupling

A		Revenue requirements ($)	100
B		Expected sales (therm)	1,000
C	(A÷B)	Price set in the rate case ($/therm)	0.1
D		Number of customers	100
E	(A÷D)	Allowed revenue per customer ($/therm)	1
F		Actual sales (therm)	950
G	(C×F)	Actual revenue ($)	95
H		Actual number of customers	101
I		Allowed revenue ($)	101
J	(I–G)	Revenue adjustment ($)	6

In this example, the revenue per customer to be collected is fixed or capped. Assuming monthly adjustments, actual revenues collected per customer are compared to the allowed revenue per customer for that month. The difference is recorded in a balancing account and reconciled periodically.

Revenue decoupling has been a part of gas ratemaking for over two decades, with revenue cap-per-customer the more commonly encountered approach.[2] Interest has increased over the past several years due to increased customer conservation in response to high gas prices and utility-funded energy efficiency initiatives. In addition, natural gas usage per household has declined more than 20 percent since the 1980s and is projected to continue to decline in the future in many jurisdictions (Costello, 2006). In such cases, decoupling provides an automatic adjustment mechanism that allows the utility to be revenue neutral and can help defer otherwise needed rate cases.

Early experience with decoupling, as recounted in Chapter 2 of the Action Plan, provides important lessons.[3] In 1991, the Maine PUC adopted a revenue decoupling mechanism in the form of revenue-per-customer cap for Central Maine Power (CMP) on a three-year trial basis. The utility's allowed revenue was determined through a rate case and adjusted annually in accordance with changes in the number of customers. CMP was allowed to file a rate case at any time to adjust its authorized revenues. With the economic downturn Maine experienced around the time the mechanism was in place, sales dipped significantly leading to a large unrecovered balance ($52 million by the end of 1992) that needed to be charged to the ratepayers. In fact, the portion of the energy efficiency-related drop in the sales was very small. Nevertheless, the program in its entirety was terminated in 1993.

Currently, a number of jurisdictions are investigating the advantages and disadvantages of decoupling, including Arizona, Colorado, Delaware, the District of Columbia, Delaware, Hawaii, Kentucky, Maryland, Michigan, New Hampshire, New Mexico, Pennsylvania, Tennessee, and Virginia. Sixteen states have adopted either gas or electric decoupling programs for at least one utility. Arkansas, New York, Utah, Oregon, Washington, Idaho, and Minnesota are among the states recently adopting decoupling programs.[4]

The following table suggests the possible pros and cons of decoupling. The specific nature of the decoupling mechanism and, in particular, the nature of adjustments for factors such as weather and economic growth, will determine the extent to which the link between sales and profits is affected.

Table 5-3. Pros and Cons of Revenue Decoupling

Pros

- Revenue decoupling weakens the link between sales and margin recovery of a utility, reducing utility reluctance to promote energy efficiency, including building codes, appliance standards, and other efficiency policies.
- Through decoupling, the utility's revenues are stabilized and shielded from fluctuations in sales. Some have argued that this, in turn, might lower its cost of capital.[5] (For a discussion of this issue, see Hansen, 2007, and Delaware PSC, 2007). The degree of stabilization is a function of adjustments made for weather, economic growth, and other factors (some mechanisms do not adjust revenues for weather or economic growth-induced changes in sales).[6]
- Decoupling does not require an energy efficiency program measurement and evaluation process to determine the level of under-recovery of fixed costs.[7]
- Decoupling has a low administrative cost relative to specific lost revenue recovery mechanisms.
- Decoupling reduces the need for frequent rate cases and corresponding regulatory costs.

Cons

- Rates (and in the case of gas utilities, non-gas customer rates) can be more volatile between rate cases, although annual caps can be instituted.
- Where carrying charges are applied to balancing accounts, the accruals can grow quickly.
- The need for frequent balancing or true-up requires regulatory resources; may be a lesser commitment than required for frequent rate cases.

5.1.1 Case Study: Idaho's Fixed Cost Recovery Pilot Program

The mechanism adopted in Idaho to address the impacts of efficiency program-induced changes in sales should not be viewed as decoupling in the broadest sense of that term. While it contains a number of the elements found in decoupling plans, it is focused specifically on recovery of lost fixed-cost revenues. The Idaho Public Utilities Commission initiated Case No. IPC-04-15 in August 2004, to investigate financial disincentives to investment in energy efficiency by Idaho Power Company. A series of workshops was conducted, and a written report was filed with the commission in early 2005. The report pointed to two action items:

1. The development of a true-up simulation to track what might have occurred if a decoupling or true-up mechanism had been implemented for Idaho Power at the time of the last general rate case.
2. The filing of a pilot energy efficiency program that would incorporate both performance incentives and fixed-cost recovery.

During the investigation, the parties agreed that there were disincentives preventing higher energy efficiency investment by Idaho Power, but no agreement was reached on whether or not the return of lost fixed-cost revenues would result in removing the disincentives. The parties agreed to conduct a simulation of the proposed mechanism, the results of which indicated that lost fixed-cost revenues, in fact, produced barriers to energy efficiency investments and, therefore, a three-year pilot mechanism to allow recovery of fixed-cost revenue losses should be approved.

Idaho Power filed an application with the Idaho Public Utilities Commission in January of 2006, and requested authority to implement a fixed cost adjustment (FCA) decoupling or true-up mechanism for its residential and small General Service customers. The commission staff, the NW Energy Coalition, and Idaho Power negotiated a settlement agreement, and the commission approved a Joint Motion for Approval of Stipulation in December 2006.

The commission issued Order No. 30267 (Idaho PUC, 2007) approving the FCA as a three-year pilot program, noting that either staff or Idaho Power can request discontinuance of the pilot. Program implementation began on January 1, 2007, and will last through December 31, 2009, plus any carryover, although either staff or Idaho Power can request early discontinuance of the pilot. The first rate adjustment will occur June 1, 2008, and subsequent rate adjustments will occur on June 1 of each year during the term of the pilot.

The proposed FCA is applicable to residential service and small General Service customers, as the company noted that these two classes present the most fixed-cost exposure for the company. The FCA is designed to provide symmetric rate adjustment (up or down) when fixed- cost recovery per customer varies above or below a commission-established level. While this approach fits the conventional description of a decoupling mechanism, Idaho Power noted that a more accurate description of the mechanism is a "true-up." The fixed-cost portion of the revenue requirement would be established for residential and small General

Service customers at the time of a general rate case. Thereafter, the FCA would provide the mechanism to true-up the collection of fixed costs per customer to recover the difference between the fixed costs actually recovered through rates and the fixed costs authorized for recovery in the company's most recent general rate case. The FCA mechanism incorporates a 3 percent cap on annual increases, with carryover of unrecovered deferred costs to subsequent years.

The actual number of customers in the adjustment year for each customer class to which the mechanism applies is multiplied by the assumed fixed cost per customer, which is determined by dividing the total fixed costs by the total number of customers from the last general rate case. This allowed fixed-cost recovery amount is compared with the amount of fixed costs actually recovered by the Idaho Power. The actual fixed-cost recovery is determined by multiplying the weather-normalized sales for each class by the fixed-cost per kilowatt-hour rate also determined in the general rate case. The difference between the allowed and the actual fixed-cost recovered amounts is the fixed-cost adjustment for each class.

For customer billing purposes only, the commission-approved FCA adjustment is combined with the conservation program funding charge.

While recognizing the potential value of the true-up mechanism, parties have taken a cautious approach that allows the company and the commission to gain experience in implementing, monitoring, and evaluating the program. And, since the program is a pilot, program corrections or cessation will take place if it is found unsuccessful or if unintended consequences develop. From the commission's perspective, the company must demonstrate an "enhanced commitment" to energy efficiency investment resulting from implementation of the FCA, including making efficiency and load management programs widely available, supporting building code improvement activity, pursuing appliance standards, and expanding of DSM programs.

Despite the approval of the pilot, the commission staff raised a number of the technical issues related to the relationship between energy efficiency program implementation and the application of the true-up mechanism. Given that the success of the mechanism is being determined in part by how it affects the company's investment in energy efficiency, several issues were raised regarding how that commitment was to be measured and, specifically, how evidence of that commitment could be distinguished from factors affecting sales per customer unrelated to the company's energy efficiency efforts. The commission noted that FCA will require close monitoring, and the development of proper metrics to evaluate the company's performance remains an issue.

5.1.2 Case Study: New Jersey Gas Decoupling

A relatively novel decoupling mechanism has recently been approved in New Jersey. In late 2005, New Jersey Natural Gas (NJNG) and South Jersey Gas (SJG) jointly filed proposals with the New Jersey Board of Public Utilities to implement a CUA clause in a five-year pilot program. The CUA was proposed as a way to *"[s]eparate the companies' margin recoveries from throughput and to adjust margin recoveries for variances in customer usage, enabling the companies to aggressively promote conservation and energy efficiency by their customers"* (New Jersey BPU, 2006).

The companies, the New Jersey Utility Board Staff, and the Department of the Public Advocate reached a settlement agreement that was approved by the New Jersey Commission in October 2006. Through the settlement, the proposed CUA was modified and implemented on a three-year pilot basis and renamed as the Conservation Incentive Program (CIP). The CIP replaced the Weather Normalization Clause, which helped cover weather related fluctuations. The CIP is an incentive-based program that:

- Requires the companies to implement shareholder-funded conservation programs designed to aid customers in reducing their costs of natural gas and to reduce each utility's peak winter and design day system demand.
- Requires the companies to reduce gas supply related costs.
- Allows the companies to recover from customers certain non-weather margin revenue losses limited to the level of gas supply cost savings achieved.

The companies are required to make annual CIP filings, based on seven months of actual data and five months of projected data, with a June 1 filing date. The filings are to document actual results, perform the required CIP collection test, and propose the new CIP rate. Any variances from the annual filings will be trued up in the subsequent year. The board has reserved the right to review any aspect of the companies' programs, including, but not limited to, the sufficiency of program funding.

The CIP tariffs include ROE limitations on recoveries from customers for both the weather and non-weather-related components. In the case of South Jersey Gas, the ROE was set at the level of the company's most recent general rate case. The ROE for New Jersey Natural Gas was set at 10.5 percent (compared to its most recently authorized rate of 11.5 percent).

The most significant element of the CIP tariff is its requirement that, as a condition for decoupling, the utilities must reduce gas supply costs—the so-called Basic Gas Supply Service (BGSS) savings—such that consumers see no net change in costs.

The methodology employed to calculate the non-weather-related CIP surcharge, if any, is delineated in paragraph 33(a) of the stipulation. If the non-weather related CIP recovery is less than or equal to the level of available gas cost savings, the amount will be eligible for recovery through the CIP tariffs. Any portion of the non-weather CIP value that exceeds the available gas cost savings will not be recovered in the current period, will be deferred up to three years, and will be subject to an eligibility test in the subsequent period. Deferred CIP surcharges may be recovered in a future period to the extent that available gas cost savings are available to offset the deferred amount. If the pilot is terminated after the initial period, any remaining deferred CIP surcharges will not be recovered. The value of any BGSS savings during one year in excess of the non-weather CIP value cannot be carried forward for use in future year calculations.

NJNG will provide $2 million for program costs and SJG will provide $400,000 for each year of the pilot program, all of which will come from shareholders. The companies are required to provide the full cost of the programs, even if the program costs exceed the budgeted levels.

In approving the stipulation, the commission concluded with the following:

> With the CIP and the possible recovery of non-weather-related margin losses, the utilities have represented that they will actively promote conservation and energy efficiency by their customers through programs funded by their shareholders. The programs are not to replicate existing CEP programs and are to include, among other things, customized customer communications and outreach built upon the utilities' relationships with their customers. While not replicating existing CEP programs, the CIP programs include initiatives that promote customers' use of CEP programs through consistent messaging with the CEP programs. At the same time, by limiting non-weather-related CIP recovery by gas supply cost reductions, in addition to an earnings cap, the CIP gives recognition to the nexus between reductions in long-term usage and reductions in gas supply capacity requirements. By limiting any non-weather CIP recovery to offsetting gas supply cost reductions, the CIP does not just provide the utilities with a mechanism for rate recovery but ensures that the CIP results in an appropriate, concomitant reduction in gas supply costs borne by customers. In this way, customers taking BGSS will not incur any overall net rate increases arising from non-weather related load losses.
>
> (New Jersey BPU, 2006)

New Jersey Resources (NJR) recently reported its experience with the CIP. NJNG, NJR's largest subsidiary, realized 6.6 percent increase in its first-quarter earnings over last year due primarily to the impact of the recently approved CIP. The company states in a recent press release that:

> [Our] conservation Incentive Program has performed as intended, and has resulted in lower gas costs for customers and improved financial results for our shareowners. This innovative program is another example of working in partnership with our regulators to help all our stakeholders.
>
> For the three months ended December 31, 2006, NJR earned $28.1 million, or $1.01 per basic share, compared with $34.3 million, or $1.24 per basic share, last year. The decrease in earnings was due primarily to lower earnings at NJR's unregulated wholesale energy services subsidiary, NJR Energy Services (NJRES), partially offset by improved results at NJNG. NJNG earned $19.9 million in the quarter, compared with $18.7 million last year. The increase in earnings was due to the impact of the CIP and continued customer growth. Gross margin at NJNG included $11.3 million accrued for future collection from customers under the CIP.
>
> Weather in the first fiscal quarter was 18.3 percent warmer than normal and 18.2 percent warmer than last year. "Normal" weather is based on 20-year average temperatures. As with the weather normalization clause which preceded it, the impact of weather is significantly offset by the recently approved CIP, which is designed to smooth out year-to-year fluctuations on both gross margin and customers' bills that may result from changing weather and usage patterns. Included in the CIP accrual was

> $8 million associated with the warmer-than-normal weather and $3.3 million associated with non-weather factors. However, customers will realize annual savings of $10.6 million in fixed cost reductions and commodity cost savings of approximately $15 million through the first fiscal quarter.
>
> (NJR, 2007)

5.1.3 Case Study: Baltimore Gas and Electric

Baltimore Gas and Electric (BGE) has had a form of a revenue-per-customer decoupling mechanism in place since 1998 for its natural gas business. The Maryland PSC allowed BGE to implement a monthly adjustment mechanism that accounts for the effect of abnormal weather patterns on sales.

Commission Order 80460 describes Rider 8[8] as follows:

> Rider 8 is a tariff provision that serves as a "weather/number of customers adjustment clause." That is, when the weather is warmer, Rider 8 will increase BGE's revenues because gas demand is lower than normal. However, when the weather is colder than normal and gas demand is high, Rider 8 decreases BGE's revenues.
>
> (Maryland PSC, 2005)

The mechanism is implemented through the Tariff Rider 8 or Monthly Rate Adjustment. The following explains the mechanism.

- The delivery price for residential service and for general service is adjusted to reflect test year base rate revenues established in the latest base rate proceeding, after adjustment to recognize the change in the number of customers from the test year level.
- The change in revenues associated with the customer charge is the change in number of customers multiplied by the customer charge for the rate schedule.
- The change in revenues associated with throughput is the test year average use per customer multiplied by the net number of customers added since the like-month during the test year, and multiplying that product by the delivery price for the rate schedule.
- The change in revenues associated with customer charge and throughput is added to test year revenue to restate test year revenues for the month to include the revised values.
- Actual revenues collected for the month are compared to the restated test year revenues and any difference is divided by estimated sales for the second succeeding month to obtain the adjustment to the applicable delivery price.
- Any difference between actual and estimated sales is reconciled in the determination of the adjustment for a future month.

5.1.4 Case Study: Questar Gas Conservation Enabling Tariff

On December 16, 2005, Questar Gas, the Division of Public Utilities, and Utah Clean Energy (UCE) filed an application seeking approval of a three-year (pilot) Conservation Enabling Tariff (CET) and DSM Pilot Program. On September 13, 2006, Questar Gas, the Division, UCE, and the committee filed the Settlement Stipulation. The settlement was approved by the commission in October 2006 (Utah PSC, 2006). The approval of the settlement put in place the CET[9] which represents the authorized revenue-per-customer amount Questar is allowed to collect from General Service customer classes.

Questar's allowed revenue for a given month is equal to the allowed distribution non-gas (DNG) revenue per customer for that month multiplied by the actual number of customers. The difference between the actual billed General Services DNG revenue[10] and the allowed revenue for that month is the monthly accrual for that month. The formula to calculate the monthly accrual is shown below.

$$\text{allowed revenue (for each month)} =$$

$$\text{allowed revenue per customer for that month} \times \text{actual general services customers}$$

$$\text{monthly accrual} = \text{allowed revenue} - \text{actual general services DNG revenue}$$

The accrual could be positive or negative.

For illustrative purposes, the following is the currently allowed DNG revenue per customer for each month of 2007.

Table 5-4. Questar Gas DNG Revenue per Customer per Month

Month	DNG Revenue per Customer
January	$42.45
February	$34.03
March	$26.42
April	$20.34
May	$13.28
June	$10.25
July	$10.03
August	$9.44
September	$10.83
October	$15.48
November	$26.47
December	$36.51

For the purpose of keeping track of over- or under-recovery amounts on a monthly basis, the CET Deferred Account (Account 191.9) was established. At least twice a year, Questar will file with the commission a request for approval for the amortization of the amount accumulated in this account subject to the above formula. The amortization will be over a year, and the impacted customer class volumetric DNG rates will be adjusted by a uniform percentage increase or decrease. The balance in the account is subject to 6 percent annual interest rate or carrying charge applied monthly (0.5 percent each month).

The settlement states that there would be a 1-year review of the CET mechanism, and a technical workshop would be held in April 2007 commencing the 1-year evaluation process. The parties submitted testimony either supporting the continuation of the current CET mechanism beyond its first year of implementation, offering modifications or alternatives, or supporting discontinuation of the mechanism on June 1, 2007.

In testimony[11] filed by Questar supporting the continuation of the CET, the company stated the following benefits of the mechanism:

- CET allows Questar to collect the commission-allowed DNG revenue. During the first year before energy efficiency programs were in place, usage per customer increased, and over $1.7 million was credited back to customers.
- CET allows Questar to aggressively promote energy efficiency, and in 2007 the company launched six energy efficiency programs with a budget of about $7 million.
- CET aligns the interests of Questar and regulators for the benefit of customers.

Questar believes that the CET has been working as expected during its first year of implementation. The Utah Committee of Consumer Services filed testimony[12] on June 1, 2007, urging the discontinuation of the CET. The primary reason driving this recommendation is the alleged sales risk shift to consumers with little or no offsetting benefits for ratepayers assuming those risks.

As of the writing of this white paper, the proceeding is still in process and the commission is expected to reach a decision by October of 2007.

5.2 Lost Revenue Recovery Mechanisms

Lost revenue recovery mechanisms[13] are designed to recover lost margins that result, as sales fall below test year levels due to the success of energy efficiency programs. They differ from decoupling mechanisms in that they do not attempt to decouple revenues from sales, but rather try to isolate the amount of under-recovery of margin revenues due to the programs. Simply put, the margin loss resulting from reductions in sales through the implementation of a successful energy efficiency program is calculated as the product of program-induced sales reductions and the amount of margin allocated per therm or kilowatt-hour in a utility's most recent rate case. In this sense, the shortfall in revenue recovery is treated as a cost to be recovered.

Although the disincentive to invest in successful efficiency programs might be removed, lost revenue recovery mechanisms do not remove a utility's disincentive to promote/support other energy saving policies, such as building codes and appliance standards, or their incentive to see sales increase generally, since the utility still earns more profit with additional sales.

One of the most important characteristics of a lost revenue recovery mechanism is that actual savings achieved from a successful energy efficiency program must be estimated correctly. Overestimates of savings will enable a utility to over-collect, and clearly, underestimates lead to under-collection of revenue. Unfortunately, reliance on evaluation creates two complications:

- While at its most rigorous, program evaluation produces a statistically valid estimate of actual savings. Rigorous evaluation can be expensive and, in any case, will not always be recognized as such by all parties.
- Because evaluation can only occur after an action has occurred, a process built on evaluation is one with potentially significant lags built in. It is possible to conduct rolling or real-time evaluations, albeit at considerable cost. In its least defensible applications, such mechanisms are applied with little or no independent evaluation and verification.

Despite these issues, several states have implemented lost revenue recovery mechanisms in lieu of decoupling as a way to address this barrier. For example, in January 2007, the Indiana Utility Regulatory Commission granted Vectren South's application for approval of a DSM lost margin adjustment factor for electric service.[14] Order Nos. 39201 and 40322 accepted the utility's request for a lost margin tracking mechanism. Recovery is done on a customer class and cost causation basis. Vectren South's total demand-side-related lost margin to be recovered through rates during the period February to April 2007 was $577,591.[15]

Perceived advantages and disadvantages of the lost revenue recovery mechanism are summarized in the following table.

Table 5-5. Pros and Cons of Lost Revenue Recovery Mechanisms

Pros
• Removes disincentive to energy efficiency investment in approved programs caused by under-recovery of allowed revenues. • May be more acceptable to parties uncomfortable with decoupling.
Cons
• Does not remove the throughput incentive to increase sales. • Does not remove the disincentive to support other energy saving policies. • Can be complex to implement given the need for precise evaluation, and will increase regulatory costs if it is closely monitored. • Proper recovery (no over- or under-recovery) depends on precise evaluation of program savings

5.2.1 Case Study: Kentucky Comprehensive Cost Recovery Mechanism[16]

Kentucky currently allows lost revenue recovery for both electric and gas DSM programs as part of a comprehensive hybrid cost recovery mechanism. Under Kentucky Revised Statute 278.190, Kentucky's Public Service Commission determines the reasonableness of DSM plans that include components for program cost recovery, lost revenue recovery, and utility incentives for cost-effectiveness. The cost recovery mechanism can be reviewed as part of a rate proceeding, or as part of a separate, limited proceeding.

The DSM Cost Recovery Mechanism currently in effect for Louisville Gas and Electric Company LG&E) is composed of factors for DSM program cost recovery (DCR), DSM revenue from lost sales (DRLS), DSM incentive (DSMI), and DSM balance adjustment (DBA). The monthly amount computed under each of the rate schedules to which this DSM Cost Recovery Mechanism applies is adjusted by the DSM Cost Recovery Component (DSMRC) at a rate per kilowatt-hour of monthly consumption in accordance with the following formula:

$$\text{DSMRC} = \text{DCR} + \text{DRLS} + \text{DSMI} + \text{DBA}$$

The DCR includes all expected costs approved by the commission for each 12-month period for DSM programs, including costs for planning, developing, implementing, monitoring, and evaluating DSM programs. Only those customer classes to which the programs are offered are subject to the DCR. The cost of approved programs is divided by the expected kilowatt-hour sales for the next 12-month period to determine the DCR for a given rate class.

- For each upcoming 12-month period, the estimated reduction in customer usage (in kilowatt-hours) as determined for the approved programs shall be multiplied by the nonvariable revenue requirement per kilowatt-hour for purposes of determining the lost revenue to be recovered hereunder from each customer class.
- The nonvariable revenue requirement for the Residential and General Service customer class is defined as the weighted average price per kilowatt-hour of expected billings under the energy charges contained in the rate RS, VFD, RPM, and General Services rate schedules in the upcoming 12-month period, after deducting the variable costs included in such energy charges.
- The nonvariable revenue requirement for each of the customer classes that are billed under demand and energy rates (rates STOD, LC, LC-TOD, LP, and LP TOD) is defined as the weighted average price per kilowatt-hour represented by the composite of the expected billings under the respective demand and energy charges in the upcoming 12-month period, after deducting the variable costs included in the energy charges.
- The lost revenues for each customer class shall then be divided by the estimated class sales (in kilowatt-hour) for the upcoming 12-month period to determine the applicable DRLS surcharge.
- Recovery of revenue from lost sales calculated for a 12-month period shall be included in the DRLS for 36 months or until implementation of new rates pursuant to a general rate case, whichever comes first.

- Revenues from lost sales will be assigned for recovery purposes to the rate classes whose programs resulted in the lost sales.
- Revenues collected hereunder are based on engineering estimates of energy savings, expected program participation and estimated sales for the upcoming 12-month period. At the end of each such period, any difference between the lost revenues actually collected hereunder, and the lost revenues determined after any revisions of the engineering estimates and actual program participation are accounted for, shall be reconciled in future billings under the DBA component.

DSMI is calculated by multiplying the net resource savings expected from the approved programs expected to be installed during the next 12-month period times 15 percent, not to exceed 5 percent of program expenditures. Net resource savings are equal to program benefits minus utility program costs and participant costs. Program benefits are calculated based on the present value of LG&E's avoided costs over the expected program life and includes capacity and energy savings.

The DBA is calculated for each calendar year and is used to reconcile the difference between the amount of revenues actually billed through the DCR, DRLS, DSMI, and previous application of the DBA. The balance adjustment (BA) amounts include interest applied to the bill amount calculated as the average of the "3-month commercial paper rate" for the immediately preceding 12-month period. The total of the BA amounts is divided by the expected kilowatt-hour sales to determine the DBA for each rate class. DBA amounts are assigned to the rate classes with under- or over-recoveries of DSM amounts.

The levels of the various DSM cost recovery components effective April 3, 2007, for LG&E's residential customers are shown in the following table.

Table 5-6. Louisville Gas and Electric Company DSM Cost Recovery Rates

DSM cost recovery component (DCR)	0.085 ¢/kilowatt-hour
DSM revenues from lost sales (DRLS)	0.005 ¢/kilowatt-hour
DSM incentive (DSMI)	0.004 ¢/kilowatt-hour
DSM balance adjustment (DBA)	(0.010)¢/kilowatt-hour
DSMRC rates	0.084 ¢/kilowatt-hour

5.3 Alternative Rate Structures

The lost margin issue arises because some or all of a utility's current fixed costs are recovered through volumetric charges. The most straightforward resolution to the issue is to design and implement rate structures that allocate a larger share of fixed costs to customer fixed charges. SFV rate structures allocate all current fixed costs to a per customer charge that does not vary with consumption. Alternatives to the SFV design employ a consumption block structure, which allocates costs across several blocks of commodity consumption and typically places most or all of the fixed costs within the initial block. This block is designed such that most customers will always consume more than this amount and, therefore, fixed costs will be recovered regardless of the level of sales in higher blocks (American Gas Association, 2006b). This produces a declining block rate structure.

Such a rate design provides significant earnings stability for the utility in the short run, making it indifferent from a net revenue perspective to the customer's usage at any time. In this way, these alternative rate structures are similar to revenue decoupling; a utility has neither a disincentive to promote energy efficiency nor an incentive to promote increased sales. SFV and similar rate designs also are viewed by some as adhering more closely to a theoretically correct approach to cost allocation that sees fixed costs as a function of the number of customers or the level of customer demand.

This approach is most commonly discussed in the context of natural gas distribution companies, where fixed costs represent the costs to build out and maintain a distribution system. These costs tend to vary more as a function of the number of customers than of system throughput (American Gas Association, 2006c).[17] These alternative rate designs are more problematic when applied to integrated electric utilities, because fixed costs are in some cases related to the volume of electricity consumed. For example, the need for baseload capacity is driven by the level of energy consumption as much or more than by the level of peak demand. Practically, it is more difficult to allocate all fixed costs to a fixed customer charge, simply because such costs can be very high, and allocation to a fixed charge would impose serious ability-to-pay issues on lower income customers. Nevertheless, improvements in rate structures that better align energy charges with the marginal costs of energy will help reduce the throughput disincentive.

Given the overarching objective of capturing the net economic and environmental benefits of energy efficiency investments, SFV designs can significantly reduce a customer's incentive to undertake efficiency improvements because of the associated reduction in variable charges.

Table 5-7. Pros and Cons of Alternative Rate Structures

Pros
• Removes the utility's incentive to promote increased sales. • May align better with principles of cost-causation.

Cons
• May not align with cost causation principles for integrated utilities, especially in the long run. • Can create issues of income equity. • Movement to a SFV design can significantly reduce customer incentives to reduce consumption by lowering variable charges (applies more to electric than gas utilities).

5.4 Notes

1 Also known as lost revenue or lost margin recovery.

2 The National Action Plan for Energy Efficiency.

3 Also see Chapter 6, "Utility Planning and Incentive Structures," in the *EPA Clean Energy-Environment Guide to Action.*

4 The Idaho Public Utilities Commission adopted a three-year decoupling pilot in March 2007, and in April 2007, the New York Public Service Commission ordered electric and natural gas utilities to file decoupling plans within the context of ongoing and new rate cases. The Minnesota legislature recently (spring 2007) enacted legislation authorizing decoupling. List of states is taken from the Natural Resources Defense Council's map of *Gas and Electric Decoupling in the US*, June 2007.

5 The design of the decoupling mechanism can address risk-shifting through the nature of the adjustments that are included. Some states have explicitly not included weather-related fluctuations in the decoupling mechanism (the utility continues to bear weather risk). In addition, recognizing that utility shareholder risk decreases with decoupling, some decoupling plans include provisions for capturing some of the risk reduction benefits for consumers. For example, PEPCO proposed (and subsequently withdrew a proposal for a 0.25 percent reduction in its ROE to reflect lower risk. The issue is under consideration by the Delaware Commission in a generic decoupling proceeding. The Oregon Public Utilities Commission reduced the threshold above which Cascade Natural Gas must share earnings from baseline ROE plus 300 basis points, to baseline ROE plus 175 basis points.

6 The impact of decoupling in eliminating the throughput incentives is lessened as the scope of the decoupling mechanism shrinks.

7 Note, however, that as the various determinants of sales, such as weather and economic activity, are excluded from the mechanism, the need for complex adjustment and evaluation methods increases. In any case, an evaluation process should nevertheless be part of the broader energy efficiency investment process.

8 http://www.bge.com/vcmfiles/BGE/Files/Rates%20and%20Tariffs/Gas%20Service%2 Tariff/Brdr 3.doc.

9 Questar Gas Tariff PSCU 400, accessed at http://www.questargas.com/Tariffs/uttariff.pdf, Section 2.11, pages 2–17.

10 Customers' bills include a real-time, customer-specific Weather Normalization Adjustment (see Section 2.08 of the Questar Gas Tariff PSCU 400) to eliminate the impact of warmer or colder than normal weather on the DNG portion of the bill.

11 Direct Testimony of Barrie L. McKay to Support the Continuation of the Conservation Enabling Tariff for Questar Gas Company, Docket No. 05-057-T01, June 1, 2007, accessed at http://www.psc.utah.gov/gas/05docs/05057T01/535586-1-07DitTestBarrieMcKay.doc.

12 Direct Testimony of David E. Dismukes, Ph.D., on Behalf of the Utah Committee of Consumer Services, Docket No. 05-057-T01, June 1, 2007, accessed at http://www.psc.utah.gov/gas/05docs/05057T01/6-1-0753584DirTestDavidDismukesPh.D.doc.

13 Also known as lost revenue or lost margin recovery mechanisms.

14 Order issued in Cause No. 39453 DSM 59 on January 31, 2007, accessed at http://www.in.gov/iurc/portal/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631800c5033.

15 Energy efficiency traditionally has been defined as an overall reduction in energy use due to use of more efficiency equipment and practices, while load management, as a subset of demand response has been defined as reductions or shifts in demand with minor declines and sometimes increases in energy use.

16 This description quotes extensively from Louisville Gas and Electric Company's Rates, Terms, and Conditions for Furnishing Electric Service, found at http://www.eon-us.com/rsc/lge/lgereselectric.pdf.

17 Even in a gas distribution system, fixed costs do vary partly as a function of individual customer demand. The SFV rate used by Atlanta Gas Light, for example, estimates the fixed charge as a function of the maximum daily demand for gas imposed by each premise.

6: Performance Incentives

This chapter provides a practical overview of alternative performance incentive mechanisms and presents their pros and cons. Detailed case studies are provided for each mechanism.

The final financial effect is represented by incentives provided to utility shareholders for the performance of a utility's energy efficiency programs. Even if regulatory policy enables recovery of program costs and addresses the issue of lost margins, at best, two major disincentives to promotion of energy efficiency are removed. Financially, demand- and supply-side investments are still not equivalent, as the supply-side investment will generate greater earnings. However, the availability of performance incentives can establish financial equivalence and creates a clear utility financial interest in the success of efficiency programs.

Three major types of performance mechanisms have been most prevalent:

- Performance target incentives
- Shared savings incentives
- Rate of return incentives

The following table illustrates the various forms of performance incentives in effect today.[1,2,3]

Table 6-1. Examples of Utility Performance Incentive Mechanisms[4]

State	Type of Utility Performance Incentive Mechanism	Details
AZ	Shared savings	Share of net economic benefits up to 10 percent of total DSM spending.
CT	Performance target Savings and other programs goals	Management fee of 1 to 8 percent of program costs (before tax) for meeting or exceeding predetermined targets. One percent incentive is given to meet at least 70 percent of the target, 5 percent for meeting the target, and 8 percent for 130 percent of the target.
GA	Shared savings	15 percent of the net benefits of the Power Credit Single Family Home program.
HI	Shared savings	Hawaiian Electric must meet four energy efficiency targets to be eligible for incentives calculated based on net system benefits up to 5 percent.
IN	Shared savings/rate of return (utility-specific)	Southern Indiana Gas and Electric Company may earn up to 2 percent added ROE on its DSM investments if performance targets are met with one percent penalty otherwise.

State	Type of Utility Performance Incentive Mechanism	Details
KS	Rate of return incentives	2 percent additional ROE for energy efficiency investments possible.
MA	Performance target Multi-factor performance targets, savings, value, and performance	5 percent of program costs are given to the distribution utilities if savings targets are met on a program-by-program basis.
MN	Shared savings Energy savings goal	Specific share of net benefits based on cost-effectiveness test is given back to the utilities. At 150 percent of savings target, 30 percent of the conservation expenditure budget can be earned.
MT	Rate of return incentives	Two percent added ROE on capitalized demand response programs possible.
NV	Rate of return incentives	Five percent additional ROE for energy efficiency investments.
NH	Shared savings Savings and cost-effectiveness goals	Performance incentive of up to 8 to 12 percent of total program budgets for meeting cost-effectiveness and savings goals.
RI	Performance targets Savings and cost-effectiveness goals	Five performance-based metrics and savings targets by sector. Incentives from at least 60 percent of savings target up to 125 percent.
SC	N/A	Utility-specific incentives for DSM programs allowed.

6.1 Performance Targets

Mechanisms that allow utilities to capture some portion of net benefits typically include savings performance targets. Most states set performance ranges; incentives are not paid unless a utility achieves some minimum fraction of proposed savings, and incentives are capped at some level above projected savings.[5] Several states have designed multi-objective performance mechanisms. Utilities in Connecticut, for example, are eligible for "performance management fees" tied to performance goals such as lifetime energy savings, demand savings, and other measures. Incentives are available for a range of outcomes from 70 to 130 percent of pre-determined goals. The utility is not entitled to the management fee unless the utility achieves at least 70 percent of the targets. After 130 percent of the goals have been reached, no added incentive is provided. Over the incentive-eligible range of 70 to 130 percent, the utilities can earn 2 to 8 percent of total energy efficiency program expenditures.

6.1.1 Case Study: Massachusetts

The Massachusetts Department of Telecommunications and Energy Order in Docket 98-100 (February 2000)[6] allows for performance-based performance incentives where a distribution company achieves its "design" performance level (i.e., the energy efficiency program performance level that the distribution company expects to achieve). The performance tiers are defined as follows:

1. The design performance level represents the level of performance that the distribution utility expects to achieve from the implementation of the energy efficiency programs included in its proposed plan. The design performance levels are expressed in levels of savings, in energy, commodity, and capacity, and in other measures of performance as appropriate.
2. The threshold performance level (the minimum level that must be achieved for a utility to be eligible for an incentive) represents 75 percent of the utility's design performance level.
3. The exemplary performance level represents 125 percent of the utility's design performance level.

For the distribution utilities that achieve their design performance levels, the after-tax performance incentive is calculated as the product of:[7]

1. The average yield of the 3-month United States Treasury bill calculated as the arithmetic average of the yields of the 3-month United States Treasury bills issued during the most recent 12-month period, or as the arithmetic average of the 3-month United States Treasury bill's 12-month high and 12-month low, and
2. The direct program implementation costs.

A distribution utility calculates its after-tax performance incentive as the product of:

1. The percentage of the design performance level achieved, and
2. The design performance incentive level, provided that the utility will earn no incentive if its actual performance is below its threshold performance level, and will earn no more than its exemplary performance level incentive even if its actual performance is beyond its exemplary performance level.

In May 2007, the Massachusetts Department of Public Utilities issued an order approving NSTAR Electric's Energy Efficiency Plan for calendar year 2006, filed with the department in April 2006.[8] NSTAR Electric's utility performance incentive proposal contains performance categories based on savings, value, and performance determinants and allocates specific weights to each category. For its residential programs, NSTAR Electric allocates the weights for its savings, value, and performance determinants as follows: 45 percent, 35 percent, and 20 percent, respectively. For its low-income programs, the weights are 30 percent, 10 percent, and 60 percent, respectively. And for its commercial and industrial programs, NSTAR sets the weights at 45 percent, 35 percent, and 20 percent, respectively.[9]

NSTAR proposed an incentive rate equal to 5 percent (after tax) of net benefits, as opposed to the pre-approved 3-Month Treasury rate, and also requested that the exemplary performance level be set at 110 percent of design level for 2006 rather than the 125 percent threshold set by the department. The department accepted both changes. With regard to the latter, the department noted that the precision of performance measurements had improved to the point that performance could be forecast more accurately. Based on these parameters, the company estimated its annual incentive would be $2.4 million.[10]

6.2 Shared Savings

With a shared savings mechanism, utilities share the net benefits resulting from successful implementation of energy efficiency programs with ratepayers. Implicitly, net benefits are tied to the utility's avoided costs, as these costs determine the level of economic benefit achieved. Therefore, the potential upside to a utility from use of a shared savings mechanism will be greater in jurisdictions with higher avoided costs.[11] Key elements in fashioning a shared savings mechanism include:

- The degree of sharing (the percentage of net benefits retained by a utility).
- The amount to be shared (maximum dollar amount of the incentive irrespective of the sharing percentage).
- The extent to which there are penalties for failing to reach performance targets.
- The manner in which avoided costs are determined for purposes of calculating net benefits.
- The threshold values above which the sharing will begin.

6.2.1 Case Study: Minnesota

Minnesota Statute § 216B.241[12] requires Minnesota's energy utilities to invest in energy conservation improvement programs (CIP) authorized by the Minnesota Department of Commerce. Utilities are allowed to recover their costs annually. Part of the CIP cost recovery is achieved through a conservation cost recovery charge (CCRC). If a utility's CIP costs differ from the amount recovered through the CCRC, the utility can adjust its rates annually through the conservation cost recovery adjustment (CCRA). Utilities record CIP costs in a "tracker" account. The commission reviews these accounts before the utilities are authorized to make adjustments to their rates. The statute also authorizes the Minnesota Public Utilities Commission to provide an incentive rate of return, a shared savings incentive, and lost margin/fixed cost recovery.

The legislation describes the requirements of an incentive plan as follows:

> Subd. 6c. Incentive plan for energy conservation improvement.
>
> (a) The commission may order public utilities to develop and submit for commission approval incentive plans that describe the method of recovery and accounting for utility conservation expenditures and savings. In developing the incentive plans the commission shall ensure the effective involvement of interested parties.
>
> (b) In approving incentive plans, the commission shall consider:
>
> (1) Whether the plan is likely to increase utility investment in cost-effective energy conservation.

(2) Whether the plan is compatible with the interest of utility ratepayers and other interested parties.

(3) Whether the plan links the incentive to the utility's performance in achieving cost-effective conservation.

(4) Whether the plan is in conflict with other provisions of this chapter.

As explained in the Order Approving DSM Financial Incentive Plans under Docket E, G-999/CI-98-1759,[13] issued in April 2000, Minnesota Public Utilities Commission convened a round table in December 1998 to assess gas and electric DSM efforts *"to identify other DSM programs and methodologies that effectively conserve energy, to revaluate the need for gas and electric DSM financial incentives and make recommendations for elimination or redesign."*

In November 1999, a joint proposal for a shared savings DSM financial incentive plan was filed with the commission. In the same month, each of the utilities filed their proposed DSMI plans for 1999 and beyond.

The jointly proposed DSM financial incentive plan, which formed the basis for individual utility plans, was intended to replace the then current incentive plans. A primary characteristic of the proposed plan is the method for determining a utility's target energy savings used to calculate incentives. Each utility is subject to the same following formula in determining the energy savings goal:

$$(\text{approved energy savings goal} \div \text{approved budget}) \times \text{statutory minimum spending level}$$

where the statutory spending requirement is 1 percent for electric IOUs (Xcel at 2 percent) and 0.5 percent for gas utilities.

The utilities must show that their expenditures resulted in net ratepayer benefits (utility program costs netted against avoided supply-side costs). In other words, net benefits of achieving the specific percentage of energy savings goals are calculated by determining the utilities avoided costs resulting from the utility's actual CIP achievement, and subtracting the CIP costs. A portion of these benefits is given to the shareholders as an incentive. The size of the incentive depends on the percentage of the net benefits achieved. This percentage increases as the percentage of the goal reached increases. At 90 percent of the goal, the utility will receive no incentive. At 91 percent of the goal, a small percentage of its net benefits will be given to the utility. Net benefits, as mentioned, depend on the utility's avoided costs, which vary from utility to utility. In order to treat all utilities equally, the percentage values are calculated such that at 150 percent of the goals, the utility's incentive will be capped at 30 percent of its statutory spending requirement.

In the April 7, 2000 order, the commission finds that the plan is likely to increase investment in cost-effective energy conservation. The incentive grows for each incremental block of energy savings. The incentive for achieving each new increment of energy savings increases as the percentage of the goal achieved increases. No significant incentive is provided unless a utility meets or exceeds its expected energy savings at minimum spending requirements.[14]

The mechanism is designed such that if a utility's program is not cost effective, there are no net benefits and hence, no incentives. As the cost effectiveness increases, the net benefits increase, and incentives increase accordingly.

The shared savings mechanism in Minnesota has been in place since 2000. The utilities make compliance filings on February 1 of each year to demonstrate the application of the incentive mechanism to a utility's budget and energy savings target.

The 2007 compliance filing[15] of Northern States Power Company (NSP), a wholly owned subsidiary of Xcel Energy, offers useful insight into application of the electric and gas incentive mechanism, in this case incorporating goals and budgets approved in November 2006. The first table shows the basic calculation of net benefits, and the second shows the incentive amount earned by NSP at different levels of program savings.

Table 6-2. Northern States Power Net Benefit Calculation

2007 Inputs	Electric	Gas
Approved CIP energy (kWh/MCF)	238,213,749	729,086
Approved CIP budget ($)	45,504,799	5,239,557
Minimum spending[a] ($)	42,147,472	3,718,065
Energy savings @ 100% of goal[b] (kWh/MCF)	220,638,428	517,370
Estimated net benefits[c] ($)	180,402,782	65,813,455
Net benefits @ 100% of goal[d] ($)	167,092,732	46,702,175

(a) Statutory requirement. Electric: 2 percent of gross operating revenue. Gas: 0.5 percent.
(b) Energy savings at 100 percent of goal: (Minimum Spending × Goal Energy Savings) ÷ Goal Spending.
(c) Estimated net benefits are calculated from the approved cost-benefit analysis in the 2007/2008/2009 CIP Triennial Plan. For electric, estimated net benefits are equal to the sum of each program's total avoided costs minus spending. For gas, the estimated net benefit is equal to total gas CIP revenue requirements test NPV for 2007 as first and only year.
(d) Net benefits at 100 percent of goal = (Minimum Spending × Goal Net Benefits) ÷ Goal Spending

Table 6-3. Northern States Power 2007 Electric Incentive Calculation

Electric	Kilowatt-Hour	Percent of Base	Estimated Benefits Achieved	Estimated Incentive
90% of goal	198,574,585	0.00%	150,383,459	0
100% of goal	220,638,428	0.8408%	167,092,732	1,404,916
110% of goal	242,702,270	1.6816%	183,802,005	3,090,815
120% of goal	264,766,113	2.5224%	200,511,278	5,057,697
130% of goal	286,829,956	3.3632%	217,220,552	7,305,562
140% of goal	308,893,799	4.2040%	233,929,825	9,834,410
150% of goal	330,957,641	5.0448%	250,639,098	12,644,241

6.2.2 Case Study: Hawaiian Electric Company (HECO)

In Order No. 23258, the Hawaii Public Utilities Commission approved HECO's proposed energy- efficiency incentive mechanism. The order sets four energy efficiency goals that HECO must meet before being entitled to any incentive based on net system benefits (less program costs). Only positive incentives are allowed; in other words, once HECO meets and exceeds the energy efficiency goals, it is entitled to the incentive, but if it cannot achieve the goal, no penalties will apply.

The order details the approach as follows:

> The DSM Utility Incentive Mechanism will be calculated based on net system benefits (less program costs), limited to no more than the utility earnings opportunities foregone by implementing DSM programs in lieu of supply-side rate based investments, capped at $4 million, subject to the following performance requirements and incentive schedule. As indicated in section III.E.l.c., supra, the commission is not requiring negative incentives. In order to encourage high achievement, HECO must meet or exceed the megawatt-hour and megawatt Energy Efficiency goals for both the commercial and industrial sector, and the residential sector, established in section III.A., supra, for HECO to be eligible for a DSM utility incentive. If HECO fails to meet one or more of its four Energy Efficiency goals, see supra section III.A.8., HECO will not be eligible to receive a DSM utility incentive. Upon a determination that HECO is eligible for a DSM utility incentive, the next step will be to calculate the percentage by which HECO's actual performance meets or exceeds each of its Energy Efficiency goals. Then, these four percentages will be averaged to determine HECO's "Averaged Actual Performance Above Goals."
>
> (Hawaii PUC, 2007)

The incentive allowed HECO (as a percentage of net benefits) is a function of the extent to which the company exceeds its savings goals, as illustrated by the following table.

Table 6-4. Hawaiian Electric Company Shared Savings Incentive Structure

Averaged Actual Performance Above Goals	DSM Utility Incentive (% of Net System Benefits)
Meets goal	1%
Exceeds goal by 2.5%	2%
Exceeds goal by 5%	3%
Exceeds goal by 7.5%	4%
Exceeds goal by 10.0% or more	5%

The commission also provided the following example to illustrate how the mechanism works.

> Assume that HECO's 2007 actual total gross commercial and industrial energy savings is 100,893 megawatt-hours, HECO's 2007 actual total gross residential energy savings is 50,553 megawatt-hours, HECO's 2007 actual total gross

commercial and industrial demand savings is 13.416 megawatts, and HECO's 2007 actual total gross residential energy savings is 14.016 megawatts.

(Hawaii PUC, 2007)

Table 6-5. Illustration of HECO Shared Savings Calculation

Energy Efficiency Energy Savings (MWh)	2007 Goal (MWh)	2007 Actual Performance (MWh)	Energy Efficiency Goal Met?	*Actual Performance Above 2007 Goal (%)*
Commercial and industrial				
Total gross energy savings	91,549	100,893	10.21%	*Yes*
Residential				
Total gross energy savings	50,553	50,553	Yes	*0%*
	2007 Goal (MW)	2007 Actual Performance (MW)	Energy Efficiency Goal Met?	*Actual Performance Above 2007 Goal (%)*
Commercial and industrial				
Total gross demand savings	13.041	13.416	Yes	*2.88%*
Residential				
Total gross demand savings	13.336	14.016	Yes	*5.10%*
Averaged actual performance above goals	4.55%			
DSM utility incentive (% of net system benefits)	*2%*			

Source: Hawaii PUC, 2007.

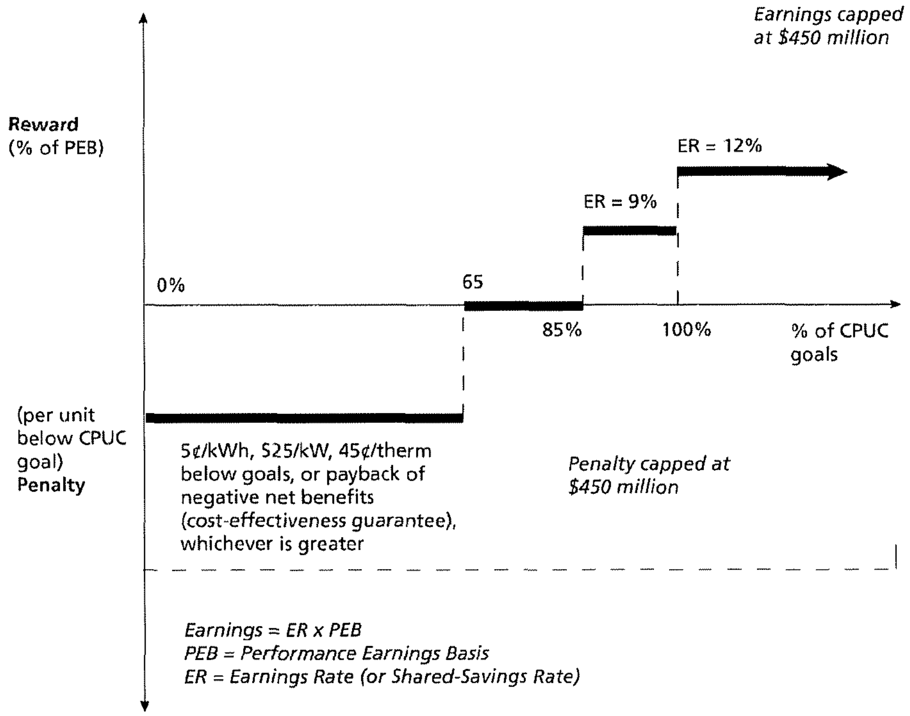
6.2.3 Case Study: The California Utilities

In September 2007, CPUC adopted a far-reaching utility performance incentives plan that creates both the potential for significant additions to utility earnings for superior performance, and significant penalties for inadequate performance.

Under the plan, shareholder incentives are tied to utilities' independently verified achievement of CPUC-established savings goals for each three-year program cycle *and* to the level of verified net benefits. Savings goals have been established for kilowatt-hours, kilowatts, and therms. To be eligible for an incentive, utilities must achieve at least 80 percent of each applicable savings goal.[16] If utilities achieve 85 percent and up to 100 percent of the simple average of all applicable goals, shareholders will receive a reward of 9 percent of verified net benefits.[17] Achievement of over 100 percent or more of the goal will yield a performance payment of 12 percent of verified net benefits, with a statewide cap of

$450 million over each three-year program cycle. Failure to achieve at least 65 percent of goal will result in performance penalties. Penalties are calculated as the greater of a charge per unit (kilowatt-hour, kilowatt, or therm) for shortfalls at or below 65 percent of goal, or a dollar-for-dollar payback to ratepayers of any negative net benefits. Total penalties also are capped statewide at $500 million. A performance dead-band of between 65 percent and 85 percent of goal produces no performance reward or penalty. Figure 6-1 and Table 6-6 illustrate the incentive structure.

Figure 6-1. California performance incentive mechanism earnings/ penalty curve.



Source: CPUC, 2007.

For example, if utilities achieve the threshold 85 percent of goal for the current 2006-2008 program period, and total verified net benefits equal the estimated value of $1.9 billion on a statewide basis, the utilities would receive 9 percent of that amount, or $175 million. If the utilities each met 100 percent of the savings goals, and the estimated verified net benefit of $2.7 billion is realized, the earnings bonus would equal $323 million.

Table 6-6. Ratepayer and Shareholder Benefits Under California's Shareholder Incentive Mechanism (Based on 2006–2008 Program Cycle Estimates)

Verified Savings % of Goals	Total Verified Net Benefits	Shareholder Earnings		Ratepayers' Savings
125%	$2,919	$450	cap	$3,469
120%	$3,673	$441		$3,232
115%	$3,427	$411		$3,016
110%	$3,181	$382		$2,799
105%	$2,935	$352		$2,583
100%	$2,689	$323		$2,366
95%	$2,443	$220		$2,223
90%	$2,197	$198		$1,999
85%	$1,951	$176		$1,775
80%	$1,705	$0		$1,705
75%	$1,459	$0		$1,459
70%	$1,213	$0		$1,213
65%	$967	($144)		$1,111
60%	$721	($168)		$889
55%	$475	($199)		$674
50%	$228	($239)		$467
45%	($18)	($276)		$258
40%	($264)	($378)		$114
35%	($510)	($450)	cap	($60)

Rewards or penalties may be collected in three installments for each three-year program cycle. Two interim reward claims or penalty assessments will be made based on estimated performance and net benefits. The third payment—a "true-up claim"—will be made after the program cycle is complete and savings and net benefits have been independently verified. Thirty percent of each interim reward payment is withheld to cover potential errors in estimated earnings calculations. Verified savings will be based on independent measurement and evaluation studies managed by CPUC.

CPUC also adjusted the basic cost-effectiveness calculations for purposes of determining net benefits. The estimated value of the performance incentives must be treated as a cost in the net benefit calculation, both during the program planning process to determine the overall cost-effectiveness of the utilities' energy efficiency portfolios, and when the value of net benefits is calculated for purposes of reward determinations subsequent to program implementation.

The commission devoted a significant portion of its order to the fundamental issues surrounding utility performance incentives—whether and why a utility should earn rewards for what are essential expenditures of ratepayer funds; the basis for determining the magnitude of the shareholder rewards; and the relationship between relative reward levels and performance. CPUC ultimately concluded that incentives were appropriate and necessary to achieve the ambitious energy efficiency goals the utilities had been given. The rewards at high levels of goal attainment were set to be generally reflective of earnings from supply-side investments foregone due to implementation of the energy efficiency programs.

Finally, the structure of what the commission termed the "earnings curve," showing the relationship between goal achievement and reward and penalty levels, was fashioned to achieve a reasonable balance between opportunity for reward and risk for penalty. And although potential penalties are significant, even in cases in which programs deliver a net benefit (but fail to meet goal), CPUC found that utilities have sufficient ability to manage these risks, such that penalties can reasonably be associated with nonperformance as opposed to uncontrollable circumstances. This last point has been contested. Utilities are subject to substantial evaluation risk in the final true-up claim. An evaluator's finding that per-unit measure savings or net-to-gross ratios[18] were significantly lower than those estimated ex ante (thus significantly lowering system net benefits) could result in utilities having to refund interim performance payments, which are based on estimates of net benefits. While utilities have some control over net-to-gross ratios through program design, there is considerable debate over the reliability of net-to-gross calculations, and even if utilities attempt to monitor the level of free ridership in a program, the final findings of an independent evaluator are unpredictable.

6.3 Enhanced Rate of Return

Under the bonus rate of return mechanism, utilities are allowed an increased return on investment for energy efficiency investments or offered a bonus return on total equity investment for superior performance. A number of states allowed an increased rate of return on energy efficiency-related investments starting in the 1980s. In fact, the majority of the states that allowed or required ratebasing or capitalization also allowed an increased rate of return for such investments. For example, Washington and Montana allowed an additional 2 percent return for energy efficiency investments, while Wisconsin adopted a mechanism where each additional 125 MW of capacity saved with energy efficiency yielded an additional 1 percent ROE. Connecticut authorized a 1 to 5 percent additional return (Reid, 1988).

Although a bonus rate of return remains an option "on the books" in a number of states, it is seldom used, largely because capitalization of efficiency investments has fallen from favor. The most often-cited current example of a bonus return mechanism, and the only one applied to a utility with significant efficiency spending, is found in Nevada. The Nevada approach, described earlier, allows a bonus rate of return for DSM that is 5 percent higher than authorized rates of return for supply investments. The earlier discussion cited the concerns raised by some that this mechanism does not provide an incentive for superior performance.

6.4 Pros and Cons of Utility Performance Incentive Mechanisms

Shared savings and performance target incentive mechanisms are similar, in that both tie an incentive to achievement of some target level of performance. The two differ in the specific nature of the target and the base upon which the incentive is calculated. The application of each mechanism will differ based on regulators' decisions regarding the specific performance target levels; the relative share of incentive base available as an incentive; the maximum amount of the incentive; and whether performance penalties can be imposed (as opposed to simply failing to earn a performance incentive). Whether an incentive mechanism is implemented will depend on how regulators balance the value of the mechanism in incenting exemplary performance against the cost to ratepayers and arguments that customers should not have to pay for a utility that simply complies with statutory or regulatory mandates. A bonus rate of return mechanism also can include performance measures (those applied in the late 1980s and early 1990s often did), but may not, as in the Nevada example. The following table summarizes the major pros and cons of performance incentive mechanisms as a whole.

Table 6-7. Pros and Cons of Utility Performance Incentive Mechanisms

Pros

- Provide positive incentives for utility investment in energy efficiency programs.
- Policy-makers can influence the types of program investments and the manner in which they are implemented through the design of specific performance features.

Cons

- Typically requires post-implementation evaluation, which entails the same issues as cited with respect to fixed-cost recovery mechanisms.
- Mechanisms without performance targets can reward utilities simply for spending, as opposed to realizing savings.
- Mechanisms without penalty provisions send mixed signals regarding the importance of performance.
- Incentives will raise the total program costs borne by customers and reduce the net benefit that they otherwise would capture.

6.5 Notes

1 For AZ, CT, MA, MN, NV, NH, and RI, see Kushler, M., D. York, and P. Witte (2006). *Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives.* Report Number U061.

2 For IN, KS, and SC, see exhibit A-26 provided with the Direct Testimony of Karl. A. McDermott before the Michigan Public Service Commission in Case No. U-13808, accessed at http://efile.mpsc.cis.state.mi.us/efile/docs/13808/0050.pdf.

3 *In the Matter of Hawaiian Electric Company, Inc., for Approval and/or Modification of Demand-Side and Load Management Programs and Recovery of Program Costs and DSM Utility Incentives,* available at http://www.hawaii.gov/budget/puc/dockets/05-0069_dno23258_2007-02-13.pdf. Note that in a prior order the Hawaii Commission eliminated specific shareholder incentives and fixed-cost recovery. However, in the instant case, the commission was persuaded to provide a shared savings incentive.

4 Vermont uses an efficiency utility, Efficiency Vermont, to administer energy efficiency programs. While not a utility in a conventional sense, Efficiency Vermont is eligible to receive performance incentives.

5 Performance targets can include metrics beyond energy and demand savings; installations of eligible equipment or market share achieved for certain products such as those bearing the ENERGY STAR™ label.

6 *Department of Telecommunications and Energy on Its Own Motion to Establish Methods and Procedures to Evaluate and Approve Energy Efficiency Programs, Pursuant to G.L. c. 25, § 19 and c. 25A, § 11G,* found at http://ww.mass.gov/Eoca/docs/dte/electric/98-100/finalguidelinesorder.pdf.

7 The following is quoted from Investigation by the Department of Telecommunications and Energy on its own motion to establish methods and procedures to evaluate and approve energy efficiency programs, pursuant to G.L. c. 25, § 19 and c. 25A, § 11G, found at http://www.mass.gov/Eoca/docs/dte/electric/98-100/finalguidelinesorder.pdf.

8 *Final Order in D.T.E./D.P.U Docket 06-45, Petition of Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company, d/b/a NSTAR Electric, Pursuant to G.L. c. 25, § 19 and G.L. c. 25A, § 11G, for Approval of Its 2006 Energy Efficiency Plan.* Found at http://www.mass.gov/Eoca/docs/dte/electric/06-45/5807dpuorder.pdf.

9 Ibid, page 9.

10 Ibid, page 10.

11 Avoided costs are the costs that would otherwise be incurred by a utility to serve the load that is avoided due to an energy efficiency program. Historically, these costs were determined administratively according to specified procedures approved by regulators. This is still the predominant approach, although some jurisdictions now use wholesale market costs to represent avoided costs. This Report will not address the derivation of these costs in detail, but note that the level of avoided costs is extremely important in determining energy efficiency program cost-effectiveness and can be the subject of substantial debate.

12 Minnesota Statute 216B.241, 2006, found at http://www.revisor.leg.state.mn.us/bin/getpub.php?type=s&year=current&num=216B.241.

13 *Order Approving Demand-Side Management Financial Incentive Plans,* Docket No. E,G-999/CI-98-1759, April 7, 2000, accessed at https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=822257.

14 Ibid, page 16.

15 *Xcel Energy Compliance Filing 2007 Electric and Gas CIP Incentive Mechanisms,* Docket E,G-999/CI-98-1759, February 1, 2007, accessed at https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=3761385.

16 PG&E and SDG&E must meet therm, kilowatt-hour, and kilowatt goals; SCE must meet kilowatt-hour and kilowatt goals; and Southern California Gas faces only a therm goal.

17 Southern California Gas need only meet the 80 percent minimum therm savings threshold to be eligible for an incentive.

18 The net-to-gross ratio is a measurement of program free ridership. Free riders are program participants who would have taken the program's intended action, even in the absence of the program.

7: Emerging Models

This chapter examines two new models currently being explored to address the basic financial effects associated with utility energy efficiency investment. The first model has been proposed as an alternative comprehensive cost recovery and performance incentive mechanism. The second represents a fundamentally different approach to funding energy efficiency within a utility resource planning and procurement framework.

Although the details of the policies and mechanisms described above for addressing the three financial effects continue to evolve in jurisdictions across the country, the basic classes of mechanisms have been understood, applied, and debated for more than two decades. Most jurisdictions currently considering policies to remove financial disincentives to utility investment in energy efficiency are considering one or more of the mechanisms described earlier. However, new models that do not fit easily within the traditional classes of mechanisms are now being considered.

7.1 Duke Energy's Proposed Save-a-Watt Model

The persistent and sometimes acrimonious nature of the debate over the proper approach to removing disincentives, combined with a sense that the energy efficiency investment environment is on the threshold of fundamental change, has led some to search for a new way to address the investment disincentive. Although no approach has yet been adopted, an intriguing proposal has emerged from Duke Energy in an energy efficiency proceeding in North Carolina.[1] Duke's energy efficiency investment plan includes an energy efficiency rider that encapsulates program cost recovery, recovery of lost margins, and shareholder incentives into one conceptually simple mechanism keyed to the utility's avoided cost. The approach is an attempt to improve upon previous methods with a more streamlined and comprehensive mechanism.

The energy efficiency rider supporting Duke's proposal is based on the notion that if energy efficiency is to be viewed from the utility's perspective as equivalent to a supply resource, the utility should be compensated for its investment in energy efficiency by an amount roughly equal to what it would otherwise spend to build the new capacity that is to be avoided. Thus, the Duke proposal would authorize the company "to recover the amortization of and a return on 90% of the costs avoided by producing save-a-watts" (Duke Energy, 2007, p. 2). There is no explicit program cost recovery mechanism, no lost margin recovery mechanism and no shareholder incentive mechanism--all such costs and incentives would be recovered under the 90 percent of avoided cost plan. According to Duke, this structure creates an explicit incentive to design and deliver programs efficiently, as doing so will minimize the program costs and maximize the financial incentive received by the company. This mechanism would apply to the full Duke demand-side portfolio, including demand-response programs.

The Duke proposal includes one element that is often not addressed explicitly in other cost recovery and incentive mechanisms, but has significant implications. A number of states have, for a variety of reasons, excluded demand response from incentive mechanisms. This becomes an issue insofar as demand response programs typically cost considerably less on a per- kilowatt basis than energy efficiency, and thus could yield substantial margins for the company under a cost recovery and incentive mechanism that pays on the basis of avoided cost. Currently available information on the proposal does not provide a basis for evaluating how significant an issue this might be (e.g., what portion of the total portfolio's impacts is due to demand response programs contained therein).

The proposed rider is to be implemented with a balancing mechanism, including annual adjustments for changes in avoided costs going forward, and to ensure that the company is compensated only for actual energy and capacity savings as determined by ex post evaluation. However, the rider is set initially based on the company's estimate of savings, and the company acknowledges that meaningful evaluation cannot occur until implementation has been underway for some time. For example, at least one year's worth of program data is required to enable valid samples to be drawn. Drawing the samples, performing data collection, and conducting analysis and report preparation can then take another six months or more. Duke's filing suggests that true-up results may lag by about three years (Duke Energy, 2007, note 4, p. 12).

The basic mechanics of the energy efficiency rider are as follows. The calculations are performed by customer class, consistent with many recovery mechanisms that, for equity reasons, allocate costs to the classes that benefit directly from the investments. The nomenclature for the class allocation has been omitted here for simplicity.

$$\mathbf{EEA = (AC + BA) \div sales}$$

Where:

EEA = Energy efficiency adjustment, expressed in \$/kWh

AC = Avoided cost revenue requirement

BA = Balance adjustment (true-up amount)

$$\mathbf{AC = (ACC + ACE) \times 0.90}$$

Where:

ACC = Avoided capacity cost revenue requirement

AEC = Avoided energy cost revenue requirement

$$ACC = DC + (ROE \times ACI) \text{ summed over each vintage year, measure/program}$$

Where:

ACI = Present value of the sum of annual avoided capacity cost (AACT), less depreciation

DC = Depreciation of the avoided cost investment

ROE = Weighted return on equity/1-effective tax rate

$$AACT = PD_{kw} \times AAC_{\$/kW/year} \text{ (for each vintage year)}$$

Where:

PD = Projected demand impacts for each measure/program by vintage year

AAC = Annual avoided costs per year, including avoided transmission costs

$$ACE = DE + (ROE \times AEI)$$

Where:

DE = Depreciation of the avoided energy investment

AEI = Present value of the sum of annual avoided energy costs (AAET), less accumulated depreciation

$$AAET = PE_{kWh} \times AEC_{\$/kWh/year} \text{ (for each vintage year)}$$

Where:

PE = Projected energy impacts by measure/program by year

AEC = Annual energy avoided costs, calculated as the difference between system energy costs with and without the portfolio of energy efficiency programs.

The mechanism's adjustment factor (BA from the first equation) addresses the true-up and is calculated as follows:

$$BA = AREP - RREP$$

Where:

AREP = Actual revenues from the evaluation period collected by the mechanism (90 percent of avoided cost)

RREP = Revenue requirements for the energy efficiency programs for the same period

All variables apply to and all calculations are performed over the "evaluation period" which is the time period to which the evaluation results apply.

$$AREP = EE \times AKWH \times RREP$$

Where:

EE = The rider charge expressed in cents/kWh

AKWH = Actual sales for the evaluation period by class

$$RREP = 90\% \times [(ACC \times (AD/PD)] + [AEC \times (AE/PE)]$$

Where:
ACC = Avoided capacity revenue requirement for the evaluation period
AD = Actual demand reduction for the period based on evaluation results
PD = Projected demand reduction for the same period
AEC = Avoided energy revenue requirement for the period
AE = Actual energy reduction for the period based on evaluation results
PE = Projected energy reduction for the period.

If evaluated savings (in kilowatt-hours and kilowatts) equal planned savings over the relevant period, then there is no adjustment.

Avoided costs are administratively determined in accordance with North Carolina rules, where avoided costs (both capacity and energy) are calculated based on the peaker methodology and are approved by the North Carolina Utilities Commission on a biannual basis (personal communication with Raiford Smith, Duke Energy, May 25, 2007).

It is important to emphasize that Duke's energy efficiency rider has only recently been filed as of this writing, and the regulatory review has only just begun. The proposal clearly represents an innovation in thinking regarding elimination of financial disincentives for utilities, and it has intuitive appeal for its conceptual simplicity. The Save-a-Watt rider *does* represent a distinct departure from cost recovery and shareholder incentives convention. In its attempt to address the range of financial effects described above in a single mechanism, the rider requires a number of detailed calculations, and estimating the amount of money to be recovered is complicated.

7.2 ISO New England's Market-Based Approach to Energy- Efficiency Procurement

The development of organized wholesale markets that allow participation from providers of load reduction creates both an alternative source of funding for energy efficiency projects and a source of revenue that potentially could be used to provide financial incentives for energy efficiency performance.

ISO New England, New England's electricity system operator and wholesale market administrator, is implementing a new capacity market, known as the forward capacity market (FCM). The FCM will, for the first time, permit all demand resources to participate in the wholesale capacity market on a comparable basis with traditional generation resources. Demand resources, as defined by ISO New England's market rules, include energy efficiency, load management, real-time demand response, and distributed generation. An annual forward capacity auction would be held to procure capacity three years in advance of delivery. This three-year window provides developers with sufficient time to construct/complete auction-clearing projects and to reduce the risk of developing new capacity. All capacity providers receive payments during the annual commitment period based upon a single clearing price set in the forward capacity auction. In return, the providers commit to providing capacity for the duration of the commitment period by producing power (if a generator) or by reducing demand (if a demand resource) during specific performance hours (typically peak load hours and shortage hours—hours in which reserves needed for reliable system operation are being depleted) (Yoshimura, 2007, pp. 1–2).

This system creates two revenue pathways. First, non-utility providers of demand reduction, such as energy service companies, municipalities, and retail customers (perhaps through aggregators), could receive a stream of revenues that could help finance incremental energy-efficiency projects. Second, utilities in the region could bid the demand reduction associated with energy efficiency programs that they are implementing. The revenues received by utilities from winning bids could be handled in a variety of ways depending on the policy of their state regulators. Traditionally, any revenues earned from these programs would be credited against the utilities' jurisdictional revenue requirement. This approach assumes the programs were funded by ratepayers and therefore, that the benefits from these programs should accrue to ratepayers. However, several alternatives exist to this approach:[2]

- Allow revenues earned from winning bids to be retained by the utilities as financial incentives. Rather than having ratepayers directly fund a performance incentive program, as is typically done, state regulators could allow utilities to retain some or all of the funds received from the capacity auction as a reward for performance and inducement to implement effective programs that reduce system peak load.
- Require that some or all of the revenues earned be applied to the expansion of existing programs or development of new programs.
- Require that the jurisdictional costs of energy efficiency programs be offset by revenues earned from the auction, resulting in a rate decrease for jurisdictional customers.

The ISO New England forward capacity auction is in its very early stages. The initial "show-of-interest" solicitation produced almost 2,500 MW of additional demand reduction potential, of which almost half was in the form of some type of energy efficiency. About 80 percent of the capacity was proposed by non-utility entities (Yoshimura, 2007, p. 4).

While this model represents a new source of revenue to fund energy efficiency investments, it also presents a novel way to capture value from energy efficiency programs by virtue of their ability to reduce wholesale power costs. Increasing the supply of capacity that is bid into the auction, particularly from lower-cost energy efficiency, would likely result in a lower market clearing price for capacity resources, which would lower overall regional capacity costs.

However, whether this model becomes a significant source of revenue to support utility energy- efficiency programs is not yet known at this time. Successful implementation of an

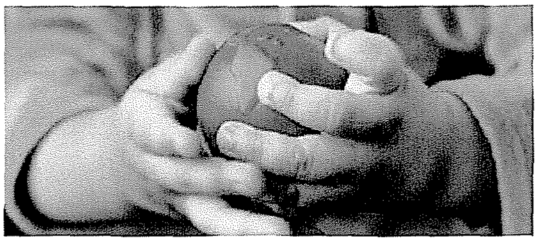
FCM that allows energy efficiency resources to participate requires that the control area responsible for resource adequacy develop rigorous and complex rules to ensure that the impacts of energy efficiency programs on capability responsibility are real and are not double-counted. Additionally, using a regional capacity market to fund energy efficiency results in all consumers of electricity within the region paying for energy efficiency programs implemented in the region. Accordingly, policy-makers in the region must be prepared for the potential shifting of energy efficiency program cost recovery from jurisdictional ratepayers to all ratepayers in the region. State regulatory policy with respect to the treatment of revenues earned in wholesale markets may or may not provide an incentive for utilities to increase the amount of energy efficiency in response to these markets. Finally, the model works only where there are organized wholesale markets that include a capacity market. Currently, much of the country operates without a capacity market.

7.3 Notes

1 The information in this chapter is drawn largely from the Application of Duke Energy Carolinas, LLC for Approval of Save-a-Watt Approach, Energy Efficiency Rider and Portfolio of Energy Efficiency Programs.

2 Note that these alternatives are not mutually exclusive.

8: Final Thoughts—Getting Started



This final chapter provides seven lessons for policy makers to consider as they begin the process of better aligning utility incentives with investment in energy efficiency.

The previous four chapters described a variety of options for addressing the barriers to efficiency investment through program cost recovery, lost margin recovery and performance incentive mechanisms. Chapter 2 underscored the principle that it is the combined effect of cost and incentive recovery that matters in the elimination of financial disincentives. There is no single optimal solution for every utility and jurisdiction. Context matters very much, and it is less important that a jurisdiction address each financial effect than that it crafts a solution that leaves utility earnings at least at pre-energy efficiency program implementation levels and perhaps higher.

The history of utility energy efficiency investment is rich with examples of how regulatory commissions and the governing bodies of publicly and cooperatively owned utilities have explored their cost recovery policy options. As these options are reconsidered and reconfigured in light of the trend toward higher utility investment in energy efficiency, this experience yields several lessons with respect to process.

1. **Set cost recovery and incentive policy based on the direction of the market's evolution.** No policy-maker sets a course by looking over his or her shoulder. Nevertheless, there is a natural tendency to project onto the future what we are most comfortable with today. The rapid development of technology, the likely integration of energy efficiency and demand response, the continuing evolution of utility industry structure, the likelihood of broader action on climate change, and a wide range of other uncertainties argue for cost recovery and incentive policies that can work with intended effect under a variety of possible futures.
2. **Apply cost recovery mechanisms and utility performance incentives in a broad policy context.** The policies that affect utility investment in energy efficiency are many and varied, and each will control, to some extent, the nature of financial incentives and disincentives that a utility faces. Policies that could impact the design of cost recovery and incentive mechanisms include those having to do with rate design (PBR, dynamic pricing, SFV designs, etc.); non-CO2 environmental controls such as NOX cap-and-trade initiatives; broader clean energy and distributed energy development; and the development of more liquid wholesale markets for load reduction programs.
3. **Test prospective policies.** Cost recovery and incentive discussions have tended toward the conceptual. What is appropriate to award and allow? Is it the utilities' responsibility to invest in energy efficiency, and do they need to be rewarded for doing so? Should revenues be decoupled from sales? All questions are appropriate and yet at the end of the day, the answers tell policy-makers very little about how a mechanism will impact

rates and earnings. This answer can only come from running the numbers—test driving the policy—and not simply under the standard business-as-usual scenario. Business is never "as usual," and a sustainable, durable policy requires that it generate acceptable outcomes under unusual circumstances. Complex mechanisms that have many moving parts cannot easily be understood absent simulation of the mechanisms under a wide range of conditions. This is particularly true of mechanisms that rely on projections of avoided costs, prices, or program impacts.

4. **Policy rules must be clear.** Earlier chapters of this Report described the relationship between perceived financial risk and utility disincentives to invest in energy efficiency. This risk is mitigated in part by having cost recovery and incentive mechanisms in place, but the effectiveness of these mechanisms depends very much on the rules governing their application. For example, review and approval of energy efficiency program budgets by regulators prior to implementation provides utilities with greater assurance of subsequent cost recovery. Alternatively, spelling out what is considered prudent in terms of planning and investment can help allay concerns over post-implementation disallowances. Similarly, the criteria/methods to be applied when reviewing costs, recovery of lost margins, and claimed incentives should be as specific as possible, recognizing the need to preserve regulatory flexibility. Where possible, the values of key cost recovery and incentive variables, such as avoided costs, should be determined in other appropriate proceedings, rather than argued in cost recovery dockets. Although this clear separation of issues will not always be possible, the principal focus of cost recovery proceedings should be on (1) whether a utility adhered to an approved plan and, if not, whether it was prudent in diverging, and (2) whether costs and incentives proposed for recovery are properly calculated.
5. **Collaboration has value.** Like every issue involving utility costs of service, recovering the costs associated with program implementation, recovering lost margins/fixed costs, and providing performance incentives will involve determinations of who should pay how much. These decisions invariably will draw active participation from a variety of stakeholders. Key among these are utilities, consumer advocates, environmental groups, energy efficiency proponents, and representatives of large energy consumers. Fashioning a cost recovery and incentives policy will be challenging. The most successful and sustainable cost recovery and incentive policies are those that (1) were based on a consultative process that includes broad agreement on the general aims of the energy efficiency investment policy, and (2) are based on legislative enactment of clear regulatory authority to implement the policy.
6. **Flexibility is essential.** Most of the states that have had significant efficiency investment and cost recovery policies in place for more than a few years have found compelling reasons to modify these policies at some point. Rather than indicating policy inconsistency, these changes most often reflect an institutional capacity to acknowledge either weaknesses in existing approaches or broader contextual changes that render prior approaches ineffective. Minnesota developed and subsequently abandoned a lost margin recovery mechanism after finding that its costs were too high, but the state replaced the mechanism with a utility performance incentive policy that appears to be

effective in addressing barriers to investment. California adopted, abandoned, and is now set to again adopt performance incentive mechanisms as it responds to broader changes in energy market structure and the role of utilities in promoting efficiency. Nevada adopted a bonus rate of return for utility efficiency investments and is now reconsidering that policy in the context of the state's aggressive resource portfolio standard. Policy stability is desirable, and changes that suggest significant impacts on earnings or prices can be particularly challenging, but it is the stability of impact rather than adherence to a particular model that is important in addressing financial disincentives to invest.

7. **Culture matters.** One important test of a cost recovery and incentives policy is its impact on corporate culture. A policy providing cost recovery is an essential first step in removing financial disincentives associated with energy efficiency investment, but it will not change a utility's core business model. Earnings are still created by investing in supply-side assets and selling more energy. Cost recovery, plus a policy enabling recovery of lost margins might make a utility indifferent to selling or saving a kilowatt-hour or therm, but still will not make the business case for aggressive pursuit of energy efficiency. A full complement of cost recovery, lost margin recovery, and performance incentive mechanisms can change this model, and likely will be needed to secure sustainable funding for energy efficiency at levels necessary to fundamentally change resource mix.

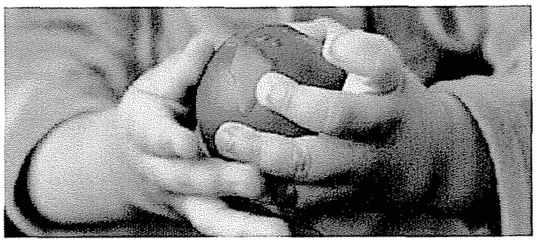
As utility spending on energy efficiency programs rises to historic levels, attention increasingly falls on the policies in place to recover program costs, recover potential lost margins, and provide performance incentives. These policies take on even greater importance if utilities are expected to go beyond current spending mandates and adopt investment in customer energy efficiency as a fundamental element of their business strategy. The financial implications of utility energy efficiency spending can be significant, and failure to address them ensures that at best, utilities will comply with policies requiring their involvement in energy efficiency, and at worst, it could lead to ineffective programs and lost opportunities.

This paper has outlined the financial implications surrounding utility funding for energy efficiency and the mechanisms available for addressing them, with the intent of supporting policies that align utility financial incentives with investment in cost-effective energy efficiency. The variety of policy options is testament to the creativity of state policy-makers and utilities, but as pressure for higher efficiency spending levels increases, the volume of the debate surrounding these options also increases. To a great extent, the debates revolve around the basic tenants of utility regulation. Some efficiency cost recovery, margin recovery, and performance incentive mechanisms imply changes in our approach to utility regulation and ratemaking.

Building the consensus necessary to support significant increases in utility administration of energy efficiency will require that these tenants be revisited. If state and federal policy-makers conclude that utilities should play an increasingly aggressive role in promoting energy efficiency, adaptations to these tenants to accommodate this role will need to be explored. An important first step may be building a common understanding around the financial implications of utility spending for efficiency, including development of a consistent cost accounting framework and terminology.

Appendix

A: National Action Plan for Energy Efficiency Leadership Group



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Appendix

B: Glossary

Decoupling: A mechanism that weakens or eliminates the relationship between sales and revenue (or more narrowly the revenue collected to cover fixed costs) by allowing a utility to adjust rates to recover authorized revenues independent of the level of sales.

Energy efficiency: The use of less energy to provide the same or an improved level of service to the energy consumer in an economically efficient way. "Energy conservation" is a term that has also been used, but it has the connotation of doing without in order to save energy rather than using less energy to perform the same or better function.

Fixed costs: Expenses incurred by the utility that do not change in proportion to the volume of sales within a relevant time period

Lost margin: The reduction in revenue to cover fixed costs, including earnings or profits in the case of investor-owned utilities. Similar to lost revenue, but concerned only with fixed cost recovery, or with the opportunity costs of lost margins that would have been added to net income or created a cash buffer in excess of that reflected in the last rate case.

Lost revenue adjustment mechanisms: Mechanisms that attempt to estimate the amount of fixed cost or margin revenue that is "lost" as a result of reduced sales. The estimated lost revenue is then recovered through an adjustment to rates.

Performance-based ratemaking: An alternative to traditional return on rate base regulation that attempts to forego frequent rate cases by allowing rates or revenues to fluctuate as a function of specified utility performance against a set of benchmarks.

Program cost recovery: Recovery of the direct costs associated with program administration (including evaluation), implementation, and incentives to program participants.

Shared savings: Mechanisms that give utilities the opportunity to share the net benefits from successful implementation of energy efficiency programs with ratepayers.

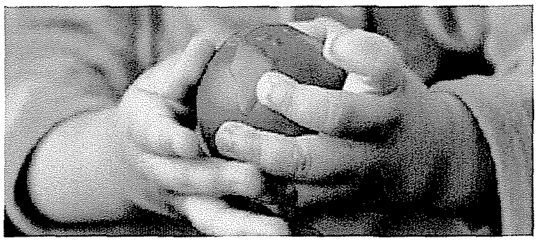
Return on equity: Based on an assessment of the financial returns that investors in that utility would expect to receive, an expectation that is influenced by the perceived riskiness of the investment.

Straight fixed-variable: A rate structure that allocates all current fixed costs to a per customer charge that does not vary with consumption.

System benefits charge: A surcharge dictated by statute that is added to ratepayers' bills to pay for energy efficiency programs that may be administered by utilities or other entities.

Throughput incentive: The incentive for utilities to promote sales growth that is created when fixed costs are recovered through volumetric charges. Many have identified the throughput incentive as the primary barrier to aggressive utility investment in energy efficiency.

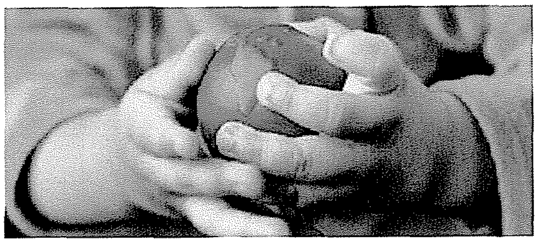
Appendix C: Sources for Table 1-2



States	Sources
Arizona	Arizona Corporation Commission, Decision Nos. 67744 and 69662 in docket E-01345A-05-0816
California	2001 California Public Utilities Code 739.10. D.04-01-048, D.04-03-23, D.04-07-022, D.05-03-023, D.04-05-055, D.05-05-055
Colorado	House Bill 1037 (2007) authorizes cost recovery and performance incentives for both gas and electric utilities
Connecticut	2005 Energy Independence Act, Section 21
District of Columbia	Code 34-3514
Florida	Florida Administrative Code Rule 25-17.015(1)
Hawaii	Docket No. 05-0069, Decision and Order No. 23258
Idaho	Idaho PUC Case numbers IPC-E-04-15 and IPC-E-06-32
Illinois	Illinois Statutes 20-687.606
Indiana	Case-by-case
Iowa	Iowa Code 2001: Section 476.6; 199 Iowa Administrative Code Chapter 35
Kentucky	Kentucky Revised Statute 278.190
Maine	Maine Statue Title 35-A
Massachusetts	D.T.E. 04-11 Order on 8/19/2004
Minnesota	Statutes 2005, 216B.24 1
Montana	Montana Code Annotated 69.8.402
Nevada	Nevada Administrative Code 704.9523
New Hampshire	Order 23-574, 2000. Statues Chapter 374-F:3
New Jersey	N.J.S.A. 46:3-60
New Mexico	New Mexico Statues Chapter 62-17-6
New York	Case 05-M-0900, In the Matter of the System Benefits Charge III, Order Continuing the System Benefits Charge (SBC)
North Carolina	Order on November 3, 2005 Docket G-21 Sub 461
Ohio	Case-by-case
Oregon	Order 02-634
Rhode Island	Rhode Island Code 39-2-1.2
Utah	www.raponline.org/showpdf.asp?PDF_URL=%22/pubs/irpsurvey/irput2.pdf%22 and Questar Order
Washington	Case-by-case
Wisconsin	Wisconsin Statute 16.957.4

Appendix

D: Case Study Detail



D.1 Iowa

199 Iowa Administrative Code Chapter 35[1] specifies the application of the cost recovery rider.

Energy efficiency cost recovery (ECR) factors, must be calculated separately for each customer or group classification. ECR factors are calculated using the following formula:

$$\text{ECR factor} = ((\text{PAC}) + (\text{ADPC} \times 12) + (\text{ECE}) + \text{A})/\text{ASU}$$

where:

- The ECR factor is the recovery amount per unit of sales over the 12-month recovery period.
- PAC is the annual amount of previously approved costs from earlier ECR proceedings, until the previously approved costs are fully recovered.
- ECE is the estimated contemporaneous expenditures to be incurred during the 12-month recovery period.
- "A" is the adjustment factor equal to over-collections or under-collections determined in the annual reconciliation, and for adjustments ordered by the board in prudence reviews.
- ASU is the annual sales units estimated for the 12-month recovery period.
- ADPC is amortized deferred past cost. It is calculated as the levelized monthly payment needed to provide a return of and on the utility's deferred past costs (DPC). ADPC is calculated as:

$$\text{ADPC} = \text{DPC}\ [r(1+r)n] \div [(1+r)n - 1]$$

where:

- DPC is deferred past costs, including carrying charges that have not previously been approved for recovery, until the deferred past costs are fully recovered.
- n is the length of the utility's plan in months.
- r is the applicable monthly rate of return calculated as:
  $r = (1+R)^{1/12} - 1$ or
  $r = R/12$ if previously approved
- R is the pretax overall rate of return the board held just and reasonable in the utility's most recent general rate case involving the same type of utility service. If the board has not rendered a decision in an applicable rate case for a utility, the average of the weighted average cost rates for each of the capital structure components allowed in general rate cases within the preceding 24 months for Iowa utilities providing the same type of utility service will be used to determine the applicable pretax overall rate of return.

D.2 Florida

The procedure for conservation cost recovery described by Florida Administrative Code Rule 25-17.015(1)[2] includes the following elements:

- Utilities submit an annual final true-up filing showing the actual common costs, individual program costs and revenues, and actual total ECCR revenues for the most recent 12-month historical period from January 1 through December 31 that ends prior to the annual ECCR proceedings. As part of this filing a utility must include:
- A summary comparison of the actual total costs and revenues reported, to the estimated total costs and revenues previously reported for the same period covered by the filing. The filing shall also include the final over- or under-recovery of total conservation costs for the final true-up period.
    - Eight months of actual and four months of projected common costs, individual program costs, and any revenues collected. Actual costs and revenues should begin January 1, immediately following the period described in paragraph (1)(a). The filing shall also include the estimated/actual over- or under-recovery of total conservation costs for the estimated/actual true-up period.
    - An annual projection filing showing 12 months of projected common costs and program costs for the period beginning January 1, following the annual hearing.
    - An annual petition setting forth proposed ECCR factors to be effective for the 12-month period beginning January 1, following the hearing.
- Within the 90 days that immediately follow the first six months of the reporting period, each utility must report the actual results for that period.
- Each utility must establish separate accounts or sub-accounts for each conservation program for the purposes of recording the costs incurred for that program. Each utility must also establish separate sub-accounts for any revenues derived from specific customer charges associated with specific programs.
- New programs or program modifications must be approved prior to a utility seeking cost recovery. Specifically, any incentives or rebates associated with new or modified programs may not be recovered if paid before approval. However, if a utility incurs prudent implementation costs before a new program or modification has been approved by the commission, a utility may seek recovery of these expenditures.

Advertising expense recovered through ECCR must be directly related to an approved conservation program, shall not mention a competing energy source, and shall not be company image-enhancing.

D.3 Notes

1 199 Iowa Administrative Code Chapter 35, accessed at http://www.legis.state.ia.us/Rules/Current/iac/199iac/19935/19935.pdf.

2 Florida Administrative Code Rule 25-17.015(1), accessed at http://www.flrules.org/gateway/RuleNo.asp?ID=25-17.015.

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KENTUCKY POLLUTION PREVENTION CENTER
UNIVERSITY OF LOUISVILLE

AMERICAN COUNCIL FOR AN ENERGY-EFFICIENT ECONOMY

Prepared for:

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An Overview of Kentucky's Energy Consumption and Energy Efficiency Potential

August 2007

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EXECUTIVE SUMMARY

The Kentucky Governor's Office of Energy Policy commissioned the Kentucky Pollution Prevention Center at the University of Louisville to conduct a preliminary study of the potential for energy efficiency in Kentucky. A growing demand for electricity, increasing strains on electric transmission infrastructure, spiking natural gas and crude oil prices, concerns about global climate change and the need to achieve energy independence have prompted a renewed focus on energy efficiency. Energy efficiency has emerged as a viable resource and the least-cost alternative to reduce these energy vulnerabilities.

Kentucky's 2005 Comprehensive Energy Strategy Report[1] identified energy efficiency as a key resource to maintain low energy costs and help address environmental concerns. Recent studies conducted by other states also conclude that energy efficiency can play a significant role in meeting future energy needs without adversely affecting the economy.[2,3,4] Given Kentucky's relatively high per capita energy consumption, similar opportunities for energy efficiency are likely to exist, but a formal evaluation of the potential offered by energy efficiency has not been made until now.

This report analyzes energy consumption in Kentucky's residential, commercial and industrial sectors and estimates the impact that energy efficiency could play in reducing future energy demand. It is intended as a starting point for discussion; additional efforts will need to address specific actions or incentives necessary to improve energy efficiency in the Commonwealth. While the methodologies differ among the sectors, the objectives are similar:

- Quantify current energy consumption and energy expenditures;
- Forecast energy consumption under a base case scenario for the 10-year period 2008 – 2017; and
- Estimate the potential for energy savings under a minimally aggressive and moderately aggressive scenario, and compare against this base case.

There is significant opportunity and value for energy efficiency in Kentucky. **Improved energy efficiency could meet all of the growth in energy demand predicted by 2017**. Under the moderately aggressive scenario, energy consumption in 2017 would be less than in 2008 by 30 trillion British thermal units (tBtu). The annual energy savings would represent more energy than 300,000[5] households use each year. Over the 10-year period, the cumulative potential from improved energy efficiency would save Kentucky 449 tBtu and $6.8 billion. This amount of energy is equivalent to the power that three 500-megawatt power plants would generate over a 10-year period.

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[1] Commonwealth Energy Policy Task Force, *Kentucky's Energy Opportunities for our Future – A Comprehensive Energy Strategy*, February 2005
[2] American Council for an Energy-Efficient Economy, *Potential for Energy Efficiency and Renewable Energy to Meet Florida's Growing Energy Demands*, February 2007
[3] American Council for an Energy-Efficient Economy, *Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas's Growing Electricity Needs*, March 2007
[4] ICF Consulting, *Assessment of Energy Efficiency Potential in Georgia*, May 2005
[5] Annual energy use for 10,000 homes is equivalent to 1 tBtu

Residential Sector

The residential sector consumed nearly 354 tBtu of energy in 2003 at a cost of $2.2 billion (2003 dollars). Electricity and natural gas comprised the majority of delivered energy at 51% and 38%, respectively (excluding electricity related losses). The primary end use for energy was space heating (42%), followed by lighting and miscellaneous equipment (32%).

From 2008 to 2017, residential consumption is expected to increase 7.8% to 458 tBtu. Under the minimally aggressive scenario, delivered energy consumption would decline by 5 tBtu in 2017 and save 23 tBtu, which represents $459 million in savings over the 10-year period. Under the moderately aggressive scenario, delivered energy consumption would decline by 15 tBtu in 2017 and save 81 tBtu, which represents a savings of $1.6 billion over the 10-year period.

Commercial Sector

The commercial sector consumed nearly 249 tBtu of energy in 2003, while total expenditures were approximately $1.4 billion. Electricity (54%) and natural gas (35%) were the dominant forms of delivered energy. Energy use for space heating (17%) and lighting (12%) was significant, however half of the energy was attributed to the "all other" category.

Energy consumption in Kentucky's commercial sector is expected to grow 22% between 2008 and 2017 – three times the increase predicted for the residential sector. Without changes, consumption is predicted to reach 382 tBtu in 2017 due, in part, to an increase in the use of electrical equipment.

Under the minimally aggressive scenario, energy consumption would decline by 2 tBtu in 2017 and save 14 tBtu representing $211 million in savings over the 10-year period. Under the moderately aggressive scenario, energy consumption would decline by 10 tBtu in 2017 and save 62 tBtu representing a savings of $950 million over the 10-year period.

Industrial Sector

Kentucky's industrial sector consumed nearly 830 tBtu of energy in 2003 at a cost of approximately $3.2 billion. Petroleum (36%), electricity (30%) and natural gas (21%) were the main forms of delivered energy consumed by the industrial sector. One-half of all electricity was used by motors; 17% was used for process heating applications. The vast majority of natural gas is used in process heating (54%) and boilers (36%).

Energy consumption in the industrial sector is expected to reach 989 tBtu in 2017, a 6.5% increase over the forecast for 2008. Under the minimally aggressive scenario, delivered energy consumption would decrease by 39 tBtu in 2017 and save 208 tBtu, which represents $3 billion in savings over the 10-year period. For the moderately aggressive scenario, delivered energy consumption would decline by 57 tBtu and save 306 tBu which represents $4.2 billion over the 10-year period. A summary of energy efficiency potential for Kentucky is provided in **Table 1**.

Table 1: Summary of Energy Efficiency Potential in Kentucky

	Annual Energy Consumption and Cost				Cumulative Delivered Energy and Cost Savings 2008 – 2017	
	*Source		Delivered		Minimally Aggressive	Moderately Aggressive
	2003	2017	2003	2017		
Residential	354 tBtu	458 tBtu	167 tBtu $2.2 billion	185 tBtu $3.9 billion	23 tBtu $459 million	81 tBtu $1.6 billion
Commercial	249 tBtu	382 tBtu	113 tBtu $1.4 billion	148 tBtu $2.4 billion	14 tBtu $211 million	62 tBtu $950 million
Industrial	830 tBtu	989 tBtu	507 tBtu $3.2 billion	580 tBtu $8.8 billion	208 tBtu $3 billion	306 tBtu $4.2 billion
Total	**1,433 tBtu**	**1,829 tBtu**	**787 tBtu $6.8 billion**	**913 tBtu $15.1 billion**	**245 tBtu $3.7 billion**	**449 tBtu $6.8 billion**

*Source is defined as total energy consumption including electricity generation and transmission losses

Conclusions

Overall, the savings potential from energy efficiency in Kentucky is large, achievable and significant – it has the promise of "supplying" the energy needs that will fuel Kentucky's growth and prosperity over the next decade.

The benefits offered from energy efficiency have a positive impact on the economy and the environment which reflect us as individuals and as a society. These benefits include:

- Reduced energy expenditures keep money in Kentucky's communities, towns and homes; money not spent for imported energy can be used to meet Kentucky's needs.
- Reduced emissions of greenhouse gasses improve the global environment while reductions in regulated pollutants, such as particulates, sulfur oxides (SO_x) and nitrous oxides (NO_x), improve local air quality.
- Creation of new markets for jobs and economic development, while helping existing Kentucky businesses and manufacturers remain profitable through improved efficiency.
- Reduced impact of higher energy prices and costs on families throughout the Commonwealth.
- Reduced energy demand slows the need for additional power generation facilities, transmission lines and pipelines.
- Reduced dependence on imported energy – much of which comes from nations that occasionally have strained relations with the United States. This decreased dependence on foreign sources of energy will increase our national security.

Energy efficiency is the fastest, cheapest and cleanest source of "new" energy. It can help reduce the strain on existing energy infrastructure and offer new solutions to slowing energy demand growth.

Seizing the opportunity that energy efficiency provides will require dedicated efforts from multiple stakeholders that must be sustained over many years. The challenge presented to the Commonwealth is how best to develop the right policies, procedures and incentives that will afford all Kentuckians the benefits of energy efficiency.

1.0 INTRODUCTION AND SCOPE

The rising cost of energy affects all facets of American society, and there are no indications that prices will decrease in the near future. In 2003, Kentuckians enjoyed one of the lowest combined utility rates throughout the nation, and the lowest retail electricity rates nationwide.[6,7] However, these low rates do not necessarily mean lower utility costs. According to the Kentucky Comprehensive Energy Strategy Report[8], released in 2005:

- Kentucky residents actually paid 1% more on their electric bills than West Virginia residents (even though our electricity rates are 9% lower).
- Although our electricity rates are 18% lower than Indiana's, our residents paid only 6% less on their electric bills.
- On an average monthly electric bill, Kentucky's schools spend 7% more per student than the national average.
- The average Kentucky industrial bill is 123% higher than the national average.
- Kentucky's average residential electric rate is 33% less than the national average but the average residential bill is only 17% below the national average.

As concluded in the Kentucky Comprehensive Energy Strategy Report, "… Kentucky's low electricity rates have encouraged energy-intensive practices, processes and procedures. This historic energy intensity provides a great opportunity for energy efficiency to help lower consumption, reduce energy bills, and improve the environment."

The purpose of this report is to provide a general indication of the energy consumption and forecasting as well as energy efficiency potential that exists within residential, commercial and industrial sectors of Kentucky. It is not designed to represent an exhaustive analysis, but rather to be viewed as a tool to identify opportunities for additional evaluation. The majority of data within this document is based on 2003 data that was available at the time this report was prepared. In some cases, older data was used, but still represents the most recent and pertinent information available.

2.0 RESIDENTIAL SECTOR

The residential sector consists of occupied housing units, including mobile homes, single-family housing units (attached and detached), and apartments.

2.1 Residential Energy Consumption

In 2003, Kentucky's residential sector consumed 353.9[9] trillion British thermal units (tBtu) of total energy, ranking the state 23rd nationwide in energy consumption.[10] The residential per

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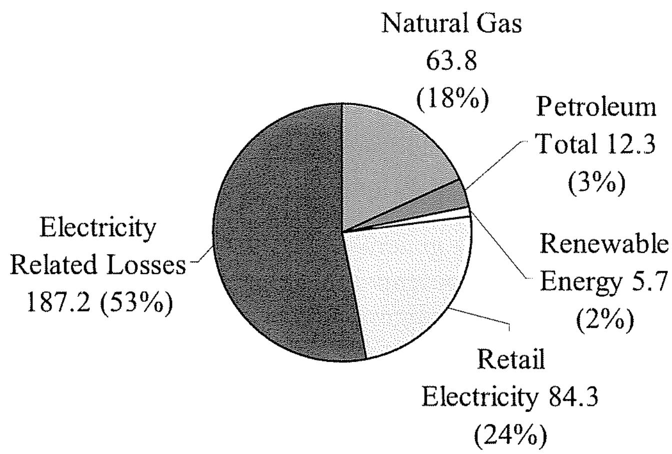
6 Energy Information Administration (EIA), *Table R1. Energy Prices and Expenditures Ranked by State, 2003*
7 EIA, *Table R4. Coal and Retail Electricity Prices and Expenditures Ranked by State, 2003*
8 Commonwealth Energy Policy Task Force, *Kentucky's Energy Opportunities for our Future – A Comprehensive Energy Strategy*, February 2005
9 EIA, *Table 8. Residential Sector Energy Consumption Estimates, Selected Years, 1960-2003, Kentucky*

capita energy consumption was estimated at 86 million Btu (MMBtu) in 2003, ranking the state 9th in the nation; this is approximately 18% above the nation's per capita use of 73 MMBtu. The total energy expenditures were $2.186 billion (2003 dollars).[11]

In 2003, per capita income for Kentuckians was $25,840[12], while per capita residential energy expenditure was estimated to be $531 or 2% of their income. For the same year, the nationwide per capita income was $31,466[13], and the energy expenditure was $615 or approximately 2% of their income. Despite Kentucky's low energy prices, Kentuckians spend the same portion of their salary on energy compared to the national average.

Kentucky's 2003 total energy consumption by energy components is provided in **Figure 1**. Over three-fourths of the energy consumed is attributed to purchased electricity and electricity-related losses. Excluding electricity losses, the majority of energy used in Kentucky homes is electricity and natural gas at 51% and 38%, respectively.

Figure 1: 2003 Kentucky Residential Sector Total Energy Consumption
353.3 Total tBtu



Note: Summary of percentages may not equal 100% due to rounding.
Coal consumption of 0.6 tBtu is not shown resulting in a total of 353.3 tBtu.
Electricity Related Losses – the amount of energy lost during generation, transmission and distribution of electricity.

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[10] EIA, *Table R1. Energy Consumption by Sector, Ranked by State, 2003*

[11] EIA, *Table S2b. Residential Sector Energy Expenditure Estimates by Source, 2003*

[12] U.S. Bureau of Economic Analysis, Regional Economic Accounts, *Bearfacts 1993-2003, Kentucky*

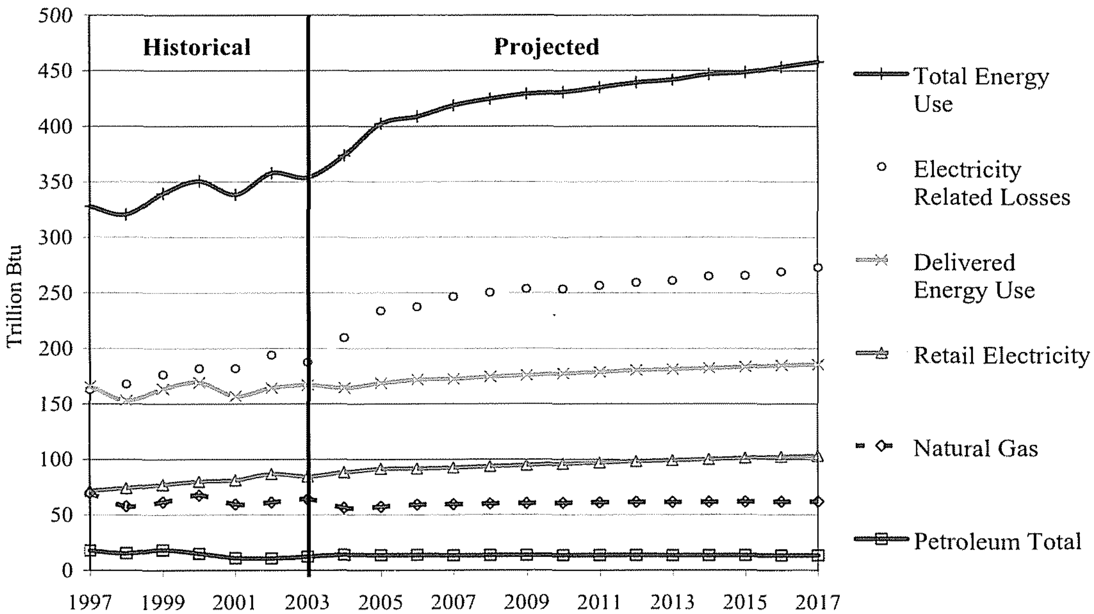
[13] U.S. Bureau of Economic Analysis, Regional Economic Accounts, *Personal Income and Per Capita Personal Income by BEA Economic Area, 2003-2005*

2.2 Residential Energy Forecast

Kentucky's historical and projected residential sector energy consumption trends for major energy sources are shown in **Figure 2**. Total energy consumption is expected to increase 7.8% from 425 tBtu in 2008 to 458 tBtu in 2017. This represents an annual average increase of 0.9%.

The energy profile from 1997 through 2003 is historical data for Kentucky[14] gathered from the U.S. Department of Energy, Energy Information Administration (EIA). Projected energy consumption for the residential sector is estimated by adjusting the forecasted energy consumption in the Annual Energy Outlook (AEO) 2006 using the National Energy Modeling System[15] (NEMS) for the East South Central region for Kentucky's household population[16] and climatic conditions (based on degree days).[17]

Figure 2: Kentucky Residential Sector Projected Energy Consumption



Note: "Total Energy Use" also includes coal and renewable energy.

2.3 Residential End Use Analysis

The majority of energy use (42%) is consumed for space heating. Lighting and other miscellaneous equipment, such as televisions and home appliances, are the second largest, consuming 32% of the total energy. A summary of end use energy consumption is provided in **Figure 3**.

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[14] EIA, *Table 8. Residential Sector Energy Consumption Estimates, Selected Years, 1960-2003, Kentucky*

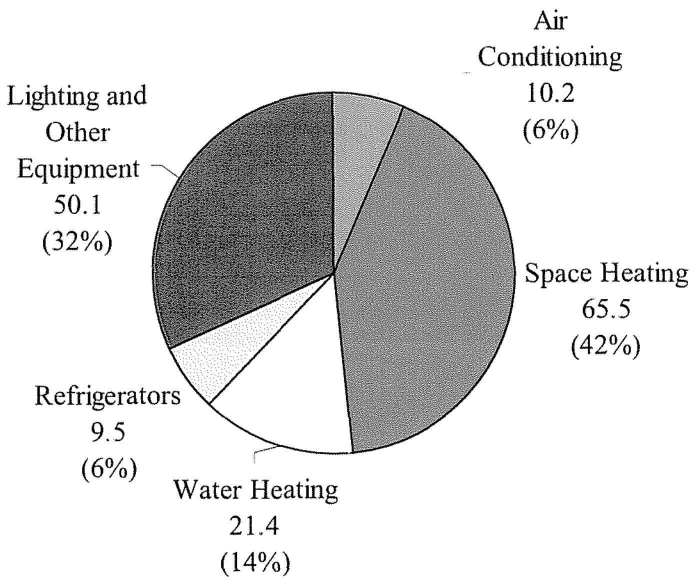
[15] EIA, *Table 6. Energy Consumption by Sector and Source – East South Central, February 2006*

[16] U.S. Census Bureau, *American Community Survey – Household Population*

[17] National Oceanic & Atmospheric Administration, *Population-Weighted Monthly Normals, 1971-2000*

Data from the 2001 Residential Energy Consumption Survey (RECS) for the East South Central region was adjusted for Kentucky's household population and climate to estimate end use energy consumption.[18] This 2001 survey is the most recent year for which information is available for this sector.

Figure 3: 2001 Kentucky Residential Sector Delivered Energy by End Use
156.7 Total tBtu



Note: Summary of percentages may not equal 100% due to rounding.

2.4 Potential for Residential Energy Savings

The residential sector was analyzed using a minimally aggressive scenario and a moderately aggressive scenario from 2008 to 2017. Assuming a minimally aggressive scenario, a 2.7% decrease in energy usage would be achieved in 2017. For the moderately aggressive scenario, an 8.2% savings would be achieved for this same period.

For the moderately aggressive scenario, the energy savings that could be achieved by 2017 are approximately 15 tBtu annually; cumulative energy savings over the same period would be approximately 81 tBtu. This is equivalent to a cumulative cost savings of $1.6 billion. A summary of the projected energy efficiency potential for the residential sector is provided in **Table 2**.

[18] EIA, *Residential Energy Consumption Survey 2001 Consumption and Expenditure Data Tables*

Table 2: Summary of Kentucky's Energy Efficiency Potential – Residential Sector

Projected Scenario	Usage/Estimated Savings
2008 Base Case Energy Usage – Delivered Energy	173 tBtu
2017 Base Case Energy Usage – Delivered Energy	183 tBtu
Percent Increase in Delivered Energy Consumption from 2008 to 2017	5.8%
2017 Minimally Aggressive Delivered Energy Savings over 2017 Base Case	5 tBtu
2017 Moderately Aggressive Delivered Energy Savings over 2017 Base Case	15 tBtu
2017 Minimally Aggressive Cumulative Delivered Energy Savings	23 tBtu
2017 Moderately Aggressive Cumulative Delivered Energy Savings	81 tBtu
2017 Minimally Aggressive Cumulative Energy Cost Savings	$459 million
2017 Moderately Aggressive Cumulative Energy Cost Savings	$1.6 billion

In AEO 2006, "Reference Case" average national residential energy intensities are forecasted until 2030. These national trends in energy intensities from 2003 to 2017 are applied to Kentucky's 2003 energy intensity estimated from EIA and U.S. Census Bureau data to forecast Kentucky's energy intensity through 2017. Kentucky's Base Case energy use is estimated from the forecasted energy intensities and projected trends in the number of households in Kentucky obtained from the University of Louisville's Kentucky State Data Center (KSDC).[19]

Energy savings for the Minimally Aggressive and Moderately Aggressive scenarios are estimated by applying, respectively, AEO 2006 "High Technology" and "Best Available Technology" energy intensity data to Base Case energy consumption. Consistent with AEO 2006 definitions, the Minimally Aggressive scenario assumes earlier availability of the most energy efficient technologies with lower costs and higher efficiencies, but does not constrain consumer choices. The Moderately Aggressive scenario assumes that the most energy efficient technology is always chosen, regardless of cost. Future energy prices are estimated by applying an average rate of increase in prices for each fuel type during the period from 1997-2003 to 2003 respective energy prices.

3.0 COMMERCIAL SECTOR

The commercial sector includes non-manufacturing businesses, such as office buildings, warehouses, retail outlets, schools and other similar types of facilities.

3.1 Commercial Energy Consumption

In 2003, Kentucky's commercial sector consumed 248.6[20] tBtu of total energy ranking the state 25th nationwide in energy consumption.[21] The total energy expenditures were $1.356 million (2003 dollars).[22]

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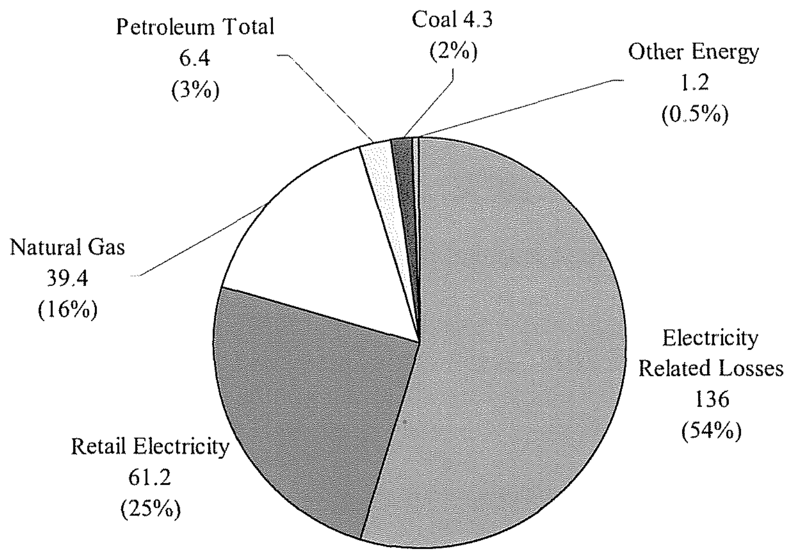
[19]KSDC, *Historical and Projected Household Populations, Number of Households, and Average Household Size, State of Kentucky, Area Development Districts, and Counties*
[20] EIA, *Table 9. Commercial Sector Energy Consumption Estimates, Selected Years, 1960-2003, Kentucky*

Kentucky's total energy consumption by energy components for 2003 is provided in **Figure 4**. Over three-fourths of energy is from purchased electricity and electricity related losses. Approximately 54% of total energy was lost in electricity related losses. Excluding electricity losses, the energy used in commercial buildings is predominantly electricity (54%) and natural gas (35%).

Figure 4: 2003 Kentucky Commercial Sector Total Energy Consumption 248.5 Total tBtu



Note: Summary of percentages may not equal 100% due to rounding.
"Other Energy" includes biomass and geothermal.

3.2 Commercial Energy Forecast

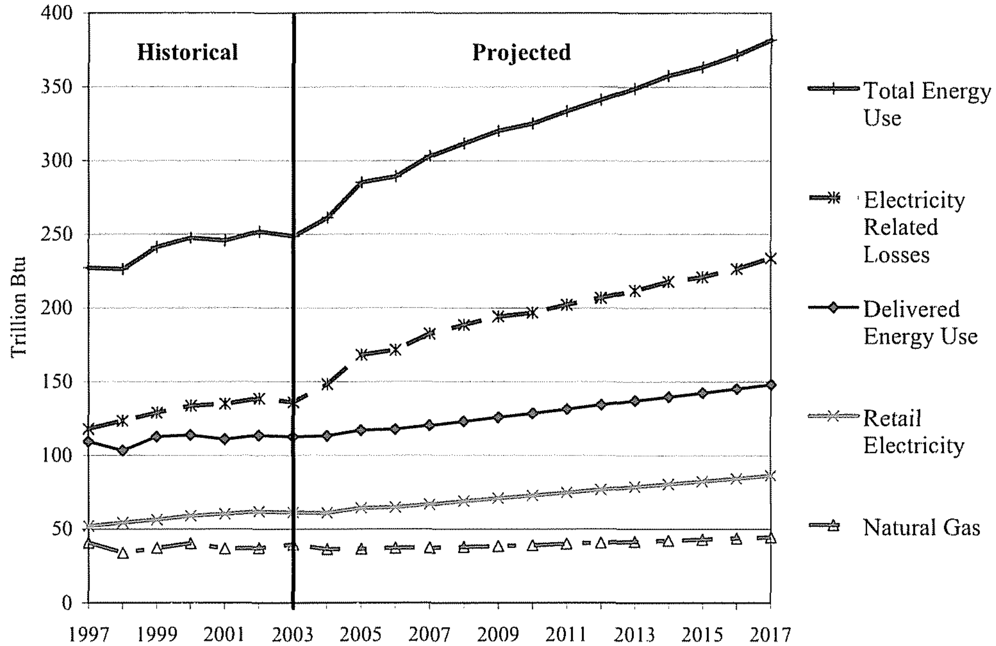
Figure 5 illustrates Kentucky historical and projected commercial sector trends for major energy sources. From 2008 to 2017, total energy consumption is expected to increase 22.4% from 312 tBtu to 382 tBtu. This represents a 2.5% annual average increase and is approximately three times greater than the rate of increase for the residential sector.

[21] EIA, *Table R1. Energy Consumption by Sector, Ranked by State, 2003*
[22] EIA, *Table S3b. Commercial Sector Energy Expenditure Estimates by Source, 2003*

The profile from 1997 through 2003 is based on historical data for Kentucky gathered from EIA.[23] The trends from 2004 through 2017 are forecasts derived from the NEMS model.[24] Applying the NEMS model, Kentucky's delivered energy intensity (kBtu/ft^2/yr) for the commercial sector is expected to increase from 135 kBtu/ft^2/yr in 2008 to 151.3 kBtu/ft^2/yr by 2017 due to increased use of electronic equipment (despite anticipated improved efficiencies in modern equipment).

The methodology to forecast commercial sector energy consumption is based first on applying Kentucky's historic (1997-2003) energy components (as a percentage) to the forecasted energy consumption in the AEO 2006 for the East South Central region. Then, the 2003 EIA Commercial Buildings Energy Consumption Survey (CBECS) data[25] for the East South Central region was adjusted for Kentucky's 2003 population. Finally, the growth in commercial space was assumed to increase at the same rate as the state's population as estimated by KSDC.[19] Forecasted energy usages and square footages are used to estimate energy intensities.

Figure 5: Kentucky Commercial Sector Projected Energy Consumption



Note: "Total Energy Use" also includes petroleum, coal, biomass and geothermal.

3.3 Commercial Energy Consumption: Sub-Sector and End Use Analysis

In 2003, Kentucky had approximately 85,300 commercial structures, which accounted for an estimated 881 million square feet.[26] **Table 3** provides the 2003 energy intensity for various commercial buildings on a national basis. Food Service is the most energy intensive sub-sector

[23] EIA, *Table 9. Commercial Sector Energy Consumption Estimates, Selected Years, 1960-2003, Kentucky*
[24] EIA, *Table 6. Energy Consumption by Sector and Source – East South Central, February 2006*
[25] CBECS, *Table A3. Census Region and Division, Number of Buildings for All Buildings (Including Malls), 2003, East South Central*

using approximately 227 $kBtu/ft^2/yr$, followed by the Health Care and Food Sales sectors. The variation in energy intensity observed among the sub-sectors is likely attributed to several factors, particularly the number of hours of daily activity and the type and prevalence of specialized equipment.

Figure 6 shows 2003 commercial sector delivered energy by end use. The majority of energy use (50%) is consumed by the category "All Other," which may include specialized equipment for hospitals, laboratories, and other similar facilities that have not been specified in AEO 2006. Space heating is the second largest, consuming 17% of the total energy.

National energy intensities for buildings with various principal building activities are estimated from AEO 2006 and presented in **Table 3**. National energy intensity percentages for specific end uses were estimated from AEO 2006 and applied to Kentucky's 2003 delivered energy consumption to estimate energy consumption by end uses.

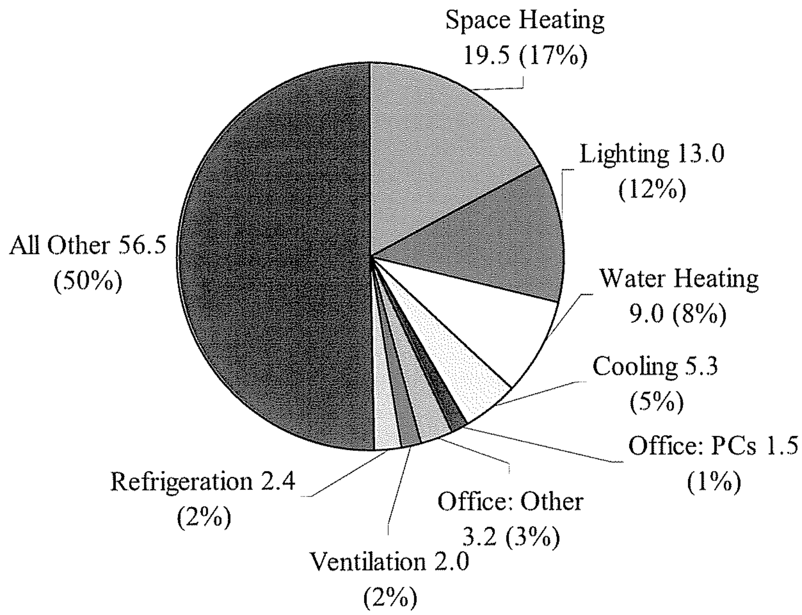
Table 3: 2003 National Commercial Building Energy Intensity (delivered energy)

Commercial Building Types	Energy Intensity ($kBtu/ft^2/yr$)
Food Service	226.5
Health Care	209.1
Food Sales	195.0
Office – Large	91.7
Lodging	90.6
Mercantile/Service	81.4
Education	74.1
Office – Small	66.5
Public Assembly	59.4
Warehouse	42.9
Other	78.8

Source: AEO 2006, *Table 22. Commercial Sector Energy Consumption, Floorspace, and Equipment Efficiency*

[26] CBECS, *Table A4. Census Region and Division, Floorspace for All Buildings (Including Malls), 2003, East South Central*

Figure 6: 2003 Kentucky Commercial Sector Delivered Energy by End Use
112.4 Total tBtu



Note: Summary of percentages may not equal 100% due to rounding.

3.4 Potential for Commercial Energy Savings

The commercial sector was analyzed using the minimally aggressive and moderately aggressive scenarios from 2008 to 2017. Assuming a minimally aggressive scenario, a 1.5% savings in energy usage would be achieved by 2017. For the moderately aggressive scenario, a 6.8% savings would be achievable in the same period. For the moderately aggressive scenario, the annual energy savings that could be achieved by 2017 are approximately 10 tBtu, and the cumulative savings over the same period are approximately 62 tBtu. The results suggest that up to $950 million in cumulative potential savings is achievable under a moderately aggressive scenario. A summary of the projected energy efficiency potential for the commercial sector is provided in **Table 4**.

Table 4: Summary of Kentucky's Energy Efficiency Potential – Commercial Sector

Projected Scenario	Usage/Estimated Savings
2008 Base Case Energy Usage – Delivered Energy	123 tBtu
2017 Base Case Energy Usage – Delivered Energy	148 tBtu
Percent Increase in Delivered Energy from 2008 to 2017	20.3%
2017 Minimally Aggressive Delivered Energy Savings over 2017 Base Case	2 tBtu
2017 Moderately Aggressive Delivered Energy Savings over 2017 Base Case	10 tBtu
2017 Minimally Aggressive Cumulative Delivered Energy Savings	14 tBtu
2017 Moderately Aggressive Cumulative Delivered Energy Savings	62 tBtu
2017 Minimally Aggressive Cumulative Energy Cost Savings	$211 million
2017 Moderately Aggressive Cumulative Energy Cost Savings	$950 million

Energy savings for the Minimally Aggressive and Moderately Aggressive scenarios are estimated by applying, respectively, AEO 2006 "High Technology" and "Best Available Technology" commercial building energy intensity data to Base Case energy consumption (see **Section 3.2**). Future energy prices are estimated by applying an average rate of increase in prices for each fuel type during the period from 1997-2003 to 2003 respective energy prices.

4.0 INDUSTRIAL SECTOR

The Kentucky industrial sector is expansive and includes many different sub-sectors. However, not all sub-sectors are as energy intensive as others. Consequently, this report targeted only key industrial sub-sectors that consumed the majority of energy (electricity and natural gas).

4.1 Industrial Energy Consumption

In 2003, Kentucky's industrial sector consumed 829.5[27] tBtu of energy, ranking the state 11th nationwide in industrial consumption.[28] Total energy expenditures were $3.182 billion (2003 dollars).[29] **Figure 7** illustrates Kentucky's total energy consumption for the industrial sector by energy source for 2003 (this includes electrical system losses). Excluding electricity related losses, petroleum (36%), electricity (30%) and natural gas (21%) were the main forms of delivered energy consumed by the industrial sector.

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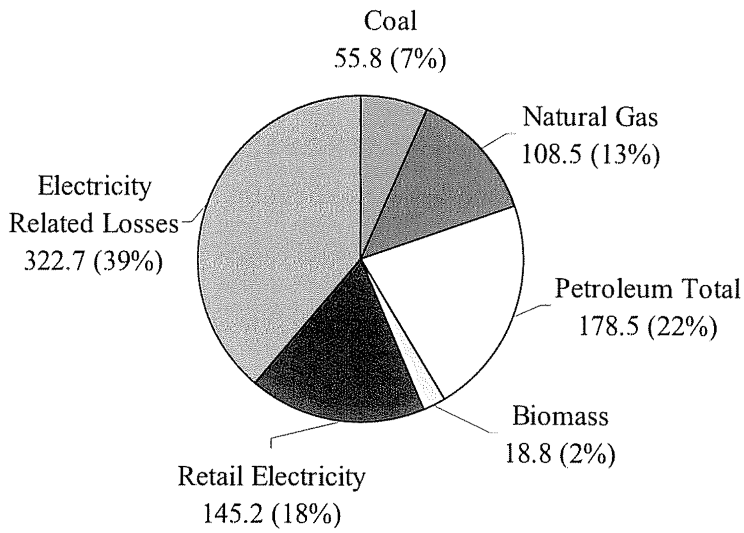
[27] EIA, *Table 10. Industrial Sector Energy Consumption Estimates, Selected Years, 1960-2003, Kentucky*
[28] EIA, *Table R1. Energy Consumption by Sector, Ranked by State, 2003*
[29] EIA, *Table 4. Industrial Sector Energy Price and Expenditure Estimates, Selected Years, 1970-2003, Kentucky*

Figure 7: 2003 Kentucky Industrial Sector Total Energy Consumption
829.5 Total tBtu



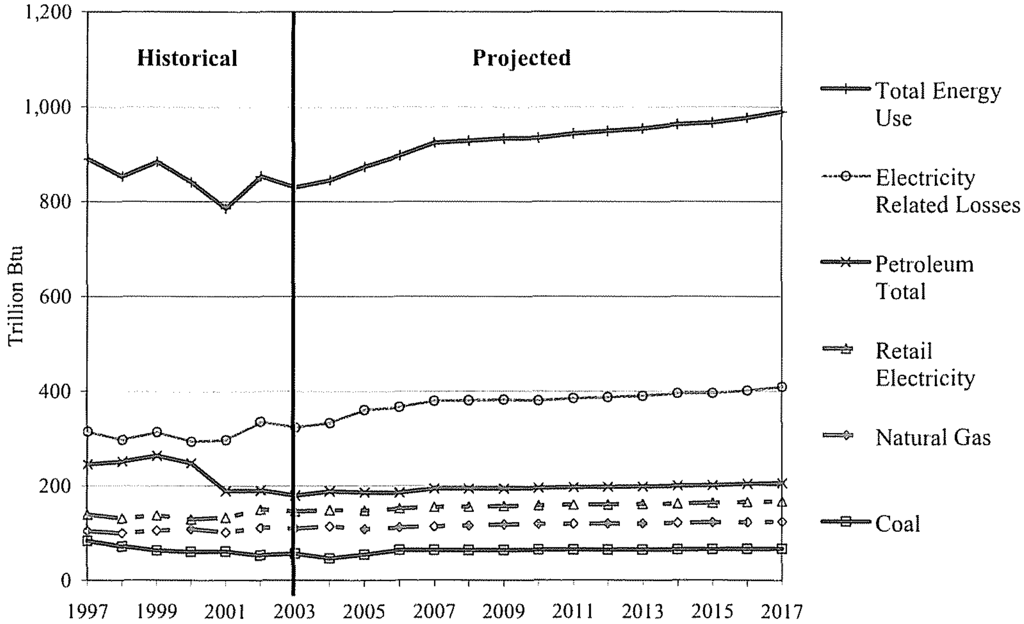
Note: Summary of percentages may not equal 100% due to rounding.

4.2 Industrial Energy Forecast

Kentucky's historical and projected industrial sector energy trends for major energy sources are provided in **Figure 8**. Based on this energy forecast, total energy consumption is expected to increase approximately 6.5%, from 929 tBtu in 2008 to 989 tBtu by 2017. This represents a 0.7% average increase each year. Historical data (from 1997 through 2003) was obtained from EIA.[30] AEO's projected increases are provided for each energy source except biomass, which is assumed to be constant at the 2003 level of 18.8 tBtu.

[30] EIA, *Table 10. Industrial Sector Energy Consumption Estimates, Selected Years, 1960-2003, Kentucky*

Figure 8: Kentucky Industrial Sector Projected Energy Consumption



Note: "Total Energy Use" also includes biomass.

4.3 Industrial Electricity Consumption: Sub-Sector and End Use Analysis

Primary metal manufacturers purchased the largest portion of electricity consumption, estimated to represent 36% of the industrial total. The chemical sector represented the second greatest electricity consumption at 13%. A summary of electricity consumption for the top seven industrial sub-sectors in Kentucky is provided in **Table 5**.

Approximately one-half of electricity consumption was attributed to motors for all sub-sectors. Process heating, which includes heat treating, melting and casting, represented approximately 17% of end uses for electricity. A summary of weighted average industrial end uses is provided in **Figure 9**. The "Total Motors" category includes pumps, fans and blowers, compressed air, material handling, material processing, refrigeration and other motors. The category "Other" includes miscellaneous equipment, such as office equipment and specialty process equipment. Although lighting and HVAC represent a relatively small percentage of the industrial sector electricity consumption, they are important in some of the key industries found in the region, such as transportation equipment manufacturers.

Data on industrial electricity consumption is not available for individual industrial sub-sectors. To estimate electricity sub-sector usage in Kentucky, the national electric intensity estimates provided in the 2002 EIA Manufacturing Energy Consumption Survey[31] (MECS) and the 2002 U.S. Census Bureau (USCB) national value of shipments[32] were applied to the USCB 2002

[31] EIA, *2002 MECS, Energy Consumption as a Fuel, Table 3.1. By Manufacturing Industry and Region (physical units)*

[32] U.S. Census Bureau, *2002 Economic Census Manufacturing Subject Series; Report Number EC02-31SG-1*

Kentucky value of shipments.[33] These were adjusted for electric intensity (defined as kilowatt-hour consumption per dollar of value of shipments) in the south census region from the 2002 MECS. The results were then calibrated to match the actual consumption for 2003. Only sub-sectors with electricity consumption greater than 4% of the total industrial electricity were included in the analysis.

The end uses of electricity in the industrial sector were estimated by using information collected in a study for the New York State Energy Research and Development Authority (NYSERDA) on industrial end uses.[34] Again, only the top seven industrial sub-sectors were considered when evaluating electricity consumption by end use.

Table 5: 2003 Estimated Electricity Consumption - Top Seven Sub-Sectors in Kentucky

NAICS Code	Industry Name	Estimated Electricity Consumption Million kWh (tBtu)	Percent of Total Industrial Electricity Consumption	Estimated Sub-Sector Costs (Million /yr)
331	Primary Metal Manufacturers	15,395 (53)	36%	$481
325	Chemical	5,414 (18)	13%	$169
336	Transportation Equipment	4,230 (14)	10%	$132
322	Paper	3,431 (12)	8%	$107
326	Plastics & Rubber Products	2,080 (7)	5%	$65
212	Mining (except oil & gas)	1,831 (6)	4%	$57
311	Food Manufacturers	1,731 (6)	4%	$54
Sub-Sector Total		**34,112 (116)**	**80%**	**$1,065**
Industrial Total		**42,570 (145)**[35]	**100%**	**$1,329**[36]

NAICS – North American Industry Classification System

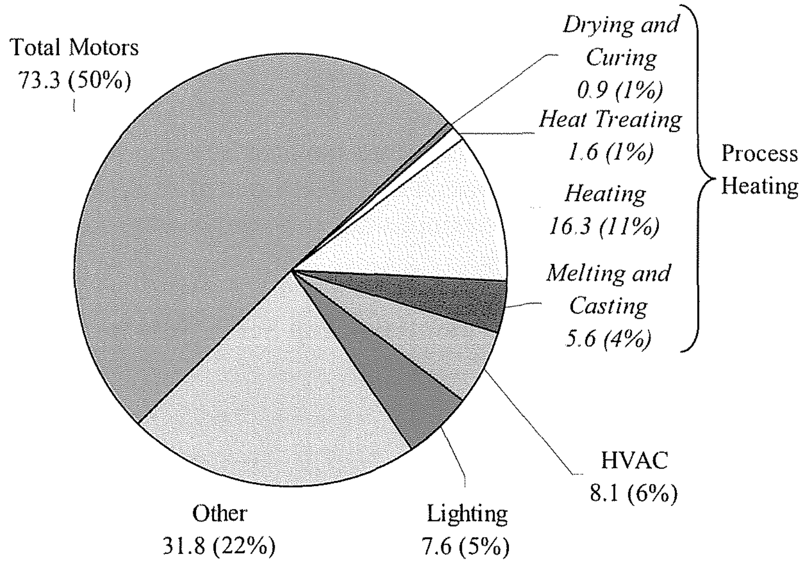
[33] U.S. Census Bureau, *2002 Economic Census Manufacturing Geographic Area Series; Report Number EC02-31A-KY (RV)*

[34] New York State Energy Research and Development Authority, *Energy Efficiency and Renewable Energy Resource Development Potential in New York State, Final Report*, May 2004

[35] EIA, *Table 10. Industrial Sector Energy Consumption Estimates, Selected Years, 1960-2003, Kentucky*

[36] EIA, *Table 4. Industrial Sector Energy Price and Expenditure Estimates, Selected Years 1970-2003, Kentucky*

Figure 9: 2003 Kentucky Weighted Average Industrial Electricity by End Use
145.2 Total tBtu



Note: Summary of percentages may not equal 100% due to rounding.

4.3.1 Potential for Industrial Electricity Savings

An analysis of 19 distinct measures for reducing electricity consumption was conducted for the Kentucky industrial sector. The savings potential for electricity as shown in **Table 6** was calculated based on the study of industrial electricity use for NYSERDA.[34] Future energy prices were estimated by applying an average rate of increase in electricity prices during the period from 1997-2003 to 2003 prices and forecasted to 2017.

The findings of this report reveal that cost-effective (minimally aggressive) investments in energy efficiency can save Kentucky industries an estimated 15.5% of electricity use by 2017, resulting in a cumulative cost savings of up to $1.7 billion. The energy savings that could be achieved with these minimally aggressive energy efficient cost-effective investments are approximately 26 tBtu annually, with a cumulative energy savings of 139 tBtu by 2017. A summary of Kentucky's electricity efficiency potential for the industrial sector is provided in **Table 7**.

The eight cost-intensive (moderately aggressive) measures would also improve efficiency, but existing technology is more expensive relative to the energy saved. These measures may become cost-effective when the cost of energy rises and the cost of the technologies fall. The energy savings that could be achieved through a moderately aggressive scenario are approximately 44 tBtu, with a cumulative energy savings of 237 tBtu by 2017. When considering all measures (cost effective and cost intensive), the total savings potential for electricity savings is over 26% by 2017, resulting in a cumulative cost savings of $2.9 billion.

Table 6: Electricity Savings Measures

Measure	Cost of Saved Energy ($/kWh saved)	Technical Savings Potential (% of Total Industrial Electricity)
Cost-Effective Measures (Minimally Aggressive)		
Pumps	0.010	3.1%
Sensors/controls	0.021	3.0%
Electric supply improvements	0.010	3.0%
Compressed air management	-	2.1%
Lighting	0.030	1.5%
Motor management	0.020	0.7%
Fans	0.030	0.7%
Lubricants	-	0.6%
Motor System Optimization	0.012	0.4%
Compressed air - advanced	-	0.1%
Refrigeration	0.004	0.4%
Subtotal		**15.5%**
Cost-Intensive Measures (Moderately Aggressive)		
Energy Information Systems	0.090	5.0%
Motor design	0.040	2.3%
Pipe insulation	0.090	1.3%
Microwave processing	0.450	1.0%
Energy Management Systems	0.450	0.6%
Transformers	0.188	0.3%
Cooling/storage – food	0.530	0.3%
HVAC	0.650	0.1%
Subtotal		**10.9%**

Source: New York State Energy Research and Development Authority, *Energy Efficiency and Renewable Energy Resource Development Potential in New York State, Final Report*, May 2004

Note: The retail industrial electricity price in 2003 in Kentucky was $0.032 per kWh. Cost-effectiveness is defined as all measures that cost less than $0.032/kWh saved over the life of the measure.
Summary of percentages may not equal subtotal due to rounding.

Table 7: Summary of Kentucky's Electricity Efficiency Potential – Industrial Sector

Projected Scenario	Usage/Estimated Savings
2008 Base Case Electricity Usage	157 tBtu
2017 Base Case Electricity Usage	167 tBtu
Percent Increase in Electricity Usage from 2008 to 2017	6.4%
2017 Minimally Aggressive Electricity Savings over 2017 Base Case	26 tBtu
2017 Moderately Aggressive Electricity Savings over 2017 Base Case	44 tBtu
2017 Minimally Aggressive Cumulative Electricity Savings	139 tBtu
2017 Moderately Aggressive Cumulative Electricity Savings	237 tBtu
2017 Minimally Aggressive Cumulative Electricity Cost Savings	$1.7 billion
2017 Moderately Aggressive Cumulative Electricity Cost Savings	$2.9 billion

4.4 Industrial Natural Gas Consumption: Sub-Sector and End Use Analysis

Primary metal manufacturing is the largest consumer of natural gas in Kentucky's industrial sector, estimated at 25% of the total natural gas consumption. Chemical manufacturing is the second largest user, estimated at 21% of the total. A summary of natural gas consumption for the top seven industrial sub-sectors is provided in **Table 8**.

Within the industrial sector, direct process heating and boilers consume the greatest natural gas, estimated at 54% and 36%, respectively (**Figure 10**). Boilers in industrial facilities are primarily used to generate steam and hot water used in manufacturing processes; direct process heat refers to usage by other process equipment, such as ovens and driers.

Data on industrial natural gas usage by sub-sector and end use consumption of natural gas is not available for Kentucky. Similar to the electricity analysis, the 2002 national energy intensities of the sub-sectors, estimated from MECS and value of shipments, were applied to the 2002 Kentucky value of shipments to estimate natural gas usage in the sub-sectors. The results were calibrated to match the actual consumption for 2003.[37] Only seven sub-sectors with gas consumption greater than 6% of the total industrial gas (representing 88% of industrial natural gas consumption in Kentucky) were evaluated in the analysis.

National end use data for sub-sectors, available in the 1998 MECS survey[38], was used in conjunction with data in **Table 8** to estimate the weighted average end use energy consumption presented in **Figure 10**.

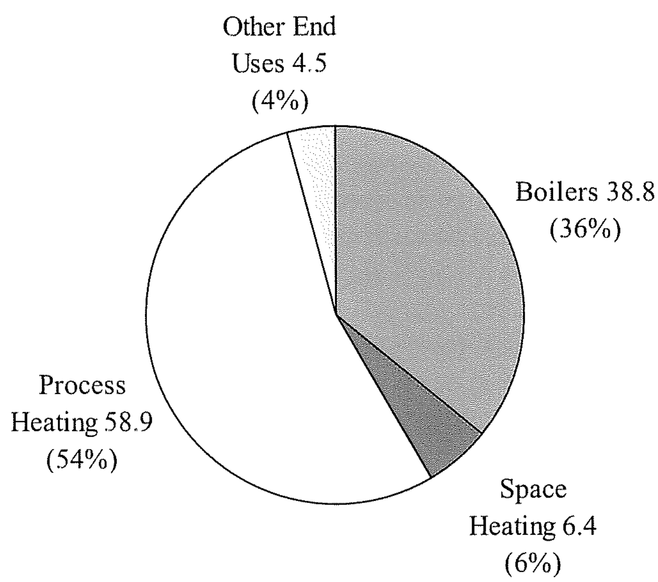
[37] EIA, *Table 10. Industrial Sector Energy Consumption Estimates, Selected Years, 1960-2003, Kentucky*
[38] EIA, MECS, *Table N6.1. End Uses of Fuel Consumption, 1998*

Table 8: 2003 Estimated Natural Gas Consumption - Top Seven Sub-Sectors in Kentucky

NAICS Code	Industry Name	Estimated Natural Gas Consumption (tBtu)	Percent of Total Industrial Consumption	Estimated Sub-Sector Costs (Million /yr)
331	Primary Metal Manufacturers	26.9	25%	$157.0
325	Chemical	22.5	21%	$131.2
322	Paper	12.5	12%	$73.2
324	Petroleum and Coal Products	10.5	10%	$61.3
336	Transportation Equipment	8.8	8%	$51.3
311	Food Manufacturers	7.2	7%	$42.3
327	Nonmetallic Mineral Products	7.1	7%	$41.6
Sub-Sector Total		**95.5**	**88%**	**$558**
Industrial Total		**108.5**[39]	**100%**	**$633.7**[40]

Note: Summary of columns may not equal sub-sector totals due to rounding.
NAICS – North American Industry Classification System

Figure 10: 2003 Kentucky Weighted Average Industrial Natural Gas by End Use
108.6 Total tBtu



Note: Summary of percentages may not equal 100% due to rounding.

[39] EIA, *Table 10. Industrial Sector Energy Consumption Estimates, Selected Years, 1960-2003, Kentucky*
[40] EIA, *Table 4. Industrial Sector Energy Price and Expenditure Estimates, Selected Years 1970-2003, Kentucky*

4.4.1 Potential for Industrial Natural Gas Savings

The savings potential for natural gas was calculated based on a study of industrial gas use in California.[41] The study calculated the 10-year achievable potential for natural gas savings in the California industrial sector. The study found that 12% of boilers, 10% of process heating, and 10% of space heating gas use could be saved in 10 years. These totals do not include estimates of how much natural gas can be saved by fuel switching. When applied to the industrial natural gas consumption in Kentucky, it is estimated that gas savings of approximately 10.3% could be achieved from 2008 to 2017 resulting in a cumulative cost savings of up to $1.3 billion. The annual energy savings that could be achieved by 2017 is approximately 13 tBtu, and the cumulative savings over the same period is approximately 69 tBtu. A summary of the natural gas efficiency potential for the industrial sector is provided in **Table 9**.

Future energy prices are estimated by applying an average rate of increase in gas prices during the period from 1997-2003 to 2003 prices and then projected to 2017.

Table 9: Summary of Kentucky's Natural Gas Efficiency Potential – Industrial Sector

Projected Scenario	Usage/Estimated Savings
2008 Base Case Natural Gas Usage	116 tBtu
2017 Base Case Natural Gas Usage	123 tBtu
Percent Increase in Natural Gas Usage from 2008 to 2017	6%
2017 Natural Gas Savings over 2017 Base Case	13 tBtu
2017 Cumulative Natural Gas Savings	69 tBtu
2017 Cumulative Natural Gas Cost Savings	$1.3 billion

5.0 SUMMARY AND CONCLUSION

Results from this report suggest that the residential, commercial and industrial sectors in Kentucky have the potential to achieve significant cost savings by implementing energy efficiency practices. Conservative estimates for implementing energy efficiency measures indicate that by 2017 Kentucky could save the following:

- Residential Sector - $459 million in savings
- Commercial Sector - $211 million in savings
- Industrial Sector - $3 billion in savings

In 2003, Kentucky was fortunate to have one of the lowest combined utility rate structures and the lowest electricity rates in the nation. According to Kentucky's Comprehensive Energy Strategy Report, these low rates encourage "... energy-intensive practices, policies and

[41] Pacific Gas and Electric Company, *California Industrial Energy Efficiency Market Characterization Study*, December 2001

procedures." Clearly, energy efficiency opportunities exist within the state. Significant improvements in energy efficiency can be achieved by implementing currently available and cost-effective technologies.

Kentucky has many options on how to achieve these potential savings. Many states have implemented or are considering implementing various incentive programs to promote energy efficiency. For example, in July 2007 Florida's Governor signed Executive Orders concerning the state's energy policy. Specifically, future state building construction will be energy efficient and include solar panels whenever possible. Office space leased in the future must be in energy efficient buildings. Additionally, the Governor requested the Public Service Commission to adopt a 20% Renewable Portfolio Standard by 2020, with a strong focus on solar and wind energy.

Overall, the savings potential from energy efficiency in Kentucky is large, achievable and significant – it has the promise of "supplying" the energy needs that will fuel Kentucky's growth and prosperity over the next decade.

The benefits offered from energy efficiency have a positive impact on the economy and the environment which reflect us as individuals and as a society. These benefits include:

- Reduced energy expenditures keep money in Kentucky's communities, towns and homes; money not spent for imported energy can be used to meet Kentucky's needs.
- Reduced emissions of greenhouse gasses improve the global environment while reductions in regulated pollutants, such as particulates, sulfur oxides (SO_x) and nitrous oxides (NO_x), improve local air quality.
- Creation of new markets for jobs and economic development, while helping existing Kentucky businesses and manufacturers remain profitable through improved efficiency.
- Reduced impact of higher energy prices and costs on families throughout the Commonwealth.
- Reduced energy demand slows the need for additional power generation facilities, transmission lines and pipelines.
- Reduced dependence on imported energy – much of which comes from nations that occasionally have strained relations with the United States. This decreased dependence on foreign sources of energy will increase our national security.

Energy efficiency is the fastest, cheapest and cleanest source of "new" energy. It can help reduce the strain on existing energy infrastructure and offer new solutions to slowing energy demand growth.

Seizing the opportunity that energy efficiency provides will require dedicated efforts from multiple stakeholders that must be sustained over many years. The challenge presented to the Commonwealth is how best to develop the right policies, procedures and incentives that will afford all Kentuckians the benefits of energy efficiency.

National Action Plan for Energy Efficiency

A PLAN DEVELOPED BY MORE THAN 50 LEADING ORGANIZATIONS IN PURSUIT OF ENERGY SAVINGS AND ENVIRONMENTAL BENEFITS THROUGH ELECTRIC AND NATURAL GAS ENERGY EFFICIENCY

JULY 2006

The goal is to create a sustainable, aggressive national commitment to energy efficiency through gas and electric utilities, utility regulators, and partner organizations.

Improving energy efficiency in our homes, businesses, schools, governments, and industries—which consume more than 70 percent of the natural gas and electricity used in the country—is one of the most constructive, cost-effective ways to address the challenges of high energy prices, energy security and independence, air pollution, and global climate change.

The U.S. Department of Energy and U.S. Environmental Protection Agency facilitate the work of the Leadership Group and the National Action Plan for Energy Efficiency.

Acknowledgements

The National Action Plan for Energy Efficiency Report discusses policy, planning, and program issues based on a formal work plan developed during the December 2005 and March 2006 Leadership Group meetings. The Leadership Group is led by co-chairs Diane Munns (Member of the Iowa Utilities Board and President of the National Association of Regulatory Utility Commissioners) and Jim Rogers (President and Chief Executive Officer of Duke Energy). A full list of Leadership Group members is provided in both the Executive Summary (Table ES-1) and Chapter 1 (Table 1-2) of this report. Rich Scheer of Energetics Inc. facilitated the Leadership Group discussions during both Leadership Group meetings.

Expert consultants, funded by the U.S. Department of Energy (DOE) and the U.S. Environmental Protection Agency (EPA), drafted many chapters of the Action Plan Report. These consultants included:

- Regulatory Assistance Project: Chapter 2 and Appendix A
- Energy and Environmental Economics, Inc.: Chapters 3 through 5, Energy Efficiency Benefits Calculator, and Appendix B
- KEMA: Chapter 6

In addition, Rich Sedano of the Regulatory Assistance Project and Alison Silverstein of Alison Silverstein Consulting provided their expertise during review and editing of the overall report.

DOE and EPA facilitated the work of the Leadership Group and this report, including Larry Mansueti with DOE's Office of Electricity Delivery and Energy Reliability, Mark Ginsberg with DOE's Office of Energy Efficiency and Renewable Energy, and Kathleen Hogan, Stacy Angel, Maureen McNamara, Katrina Pielli, and Tom Kerr with EPA's Climate Protection Partnership Division.

Eastern Research Group, Inc. provided technical review, copyediting, graphics, and production services.

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M

M&V	measurement and verification
Mcf	one thousand cubic feet
MMBtu	million British thermal units
MW	megawatt (1,000,000 watts)
MWh	megawatt-hour (1,000 kWh)

N

NEEP	Northeast Energy Efficiency Partnerships
NERC	North American Electric Reliability Council
NO_X	nitrogen oxides
NPV	net present value
NSPC	Non-Residential Standard Performance Contract
NWPCC	Northwest Power and Conservation Council
NYSERDA	New York State Energy Research and Development Authority

P

PBL	Power Business Line
PG&E	Pacific Gas & Electric
PIER	Public Interest Energy Research
PSE	Puget Sound Energy
PUCT	Public Utility Commission of Texas
PURPA	Public Utility Regulatory Policies Act

R

R&D	research and development
RARP	Residential Appliance Recycling Program
REAP	Residential Energy Affordability Partnership Program
RFP	request for proposals
RGGI	Regional Greenhouse Gas Initiative
RIM	rate impact measure
ROE	return on equity
RPC	revenue per customer
RTO	regional transmission organization
RTP	real-time pricing

S

SBC	system benefits charge
SCE	Southern California Edison
SMUD	Sacramento Municipal Utility District
SO_2	sulfur dioxide

T

TOU	time of use
TRC	total resource cost

V

VOLL	value of lost load
VOS	value of service

W

WAP	Weatherization Assistance Program

Table of Contents

Executive Summary

This National Action Plan for Energy Efficiency (Action Plan) presents policy recommendations for creating a sustainable, aggressive national commitment to energy efficiency through gas and electric utilities, utility regulators, and partner organizations. Such a commitment could save Americans many billions of dollars on energy bills over the next 10 to 15 years, contribute to energy security, and improve our environment. The Action Plan was developed by more than 50 leading organizations representing key stakeholder perspectives. These organizations pledge to take specific actions to make the Action Plan a reality.

A National Action Plan for Energy Efficiency

We currently face a set of serious challenges with regard to the U.S. energy system. Energy demand continues to grow despite historically high energy prices and mounting concerns over energy security and independence as well as air pollution and global climate change. The decisions we make now regarding our energy supply and demand can either help us deal with these challenges more effectively or complicate our ability to secure a more stable, economical energy future.

Improving the energy efficiency[1] of our homes, businesses, schools, governments, and industries—which consume more than 70 percent of the natural gas and electricity used in the country—is one of the most constructive, cost-effective ways to address these challenges.[2] Increased investment in energy efficiency in our homes, buildings, and industries can lower energy bills, reduce demand for fossil fuels, help stabilize energy prices, enhance electric and natural gas system reliability, and help reduce air pollutants and greenhouse gases.

Despite these benefits and the success of energy efficiency programs in some regions of the country, energy efficiency remains critically underutilized in the nation's energy portfolio.[3] Now we simultaneously face the challenges of high prices, the need for large investments in new energy infrastructure, environmental concerns, and security issues. It is time to take advantage of more than two decades of experience with successful energy efficiency programs, broaden and expand these efforts, and capture the savings that energy efficiency offers. Much more can be achieved in concert with ongoing efforts to advance building codes and appliance standards, provide tax incentives for efficient products and buildings, and promote savings opportunities through programs such as ENERGY STAR®. Efficiency of new buildings and those already in place are both important. Many homeowners, businesses, and others in buildings and facilities already standing today—which will represent the vast majority of the nation's buildings and facilities for years to come—can realize significant savings from proven energy efficiency programs.

Bringing more energy efficiency into the nation's energy mix to slow demand growth in a wise, cost-effective manner—one that balances energy efficiency with new generation and supply options—will take concerted efforts by all energy market participants: customers, utilities, regulators, states, consumer advocates, energy service companies (ESCOs), and others. It will require education on the opportunities, review of existing policies, identification of barriers and their solutions, assessment of new technologies, and modification and adoption of policies, as appropriate. Utilities,[4] regulators, and partner organizations need to improve customer access to energy efficiency programs to help them control their own energy costs, provide the funding necessary to deliver these programs, and examine policies governing energy companies to ensure that these policies facilitate—not impede—cost-effective programs for energy efficiency. Historically, the regulatory structure has rewarded utilities for building infrastructure (e.g., power plants, transmission lines, pipelines) and selling energy, while discouraging energy efficiency, even when the energy-saving measures cost less than constructing new infrastructure.[5] And, it has been difficult to establish the funding necessary to capture the potential benefits that cost-effective energy efficiency offers.

This National Action Plan for Energy Efficiency is a call to action to bring diverse stakeholders together at the national, regional, state, or utility level, as appropriate, and foster the discussions, decision-making, and commitments necessary to take investment in energy efficiency to a new level. The overall goal is to create a sustainable, aggressive national commitment to energy efficiency through gas and electric utilities, utility regulators, and partner organizations.

The Action Plan was developed by a Leadership Group composed of more than 50 leading organizations representing diverse stakeholder perspectives. Based upon the policies, practices, and efforts of many organizations across the country, the Leadership Group offers five recommendations as ways to overcome many of the barriers that have limited greater investment in programs to deliver energy efficiency to customers of electric and gas utilities (Figure ES-1). These recommendations may be pursued through a number of different options, depending upon state and utility circumstances.

As part of the Action Plan, leading organizations are committing to aggressively pursue energy efficiency opportunities in their organizations and assist others who want to increase the use of energy efficiency in their regions. Because greater investment in energy efficiency cannot happen based on the work of one individual or organization alone, the Action Plan is a commitment to bring the appropriate stakeholders together—including utilities, state policy-makers, consumers, consumer advocates, businesses, ESCOs, and others—to be part of a collaborative effort to take energy efficiency to a new level. As energy experts, utilities may be in a unique position to play a leading role.

The reasons behind the National Action Plan for Energy Efficiency, the process for developing the Action Plan, and the final recommendations are summarized in greater detail as follows.

Figure ES-1. National Action Plan for Energy Efficiency Recommendations

- **Recognize energy efficiency as a high-priority energy resource.**
- **Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource.**
- **Broadly communicate the benefits of and opportunities for energy efficiency.**
- **Promote sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective.**
- **Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments.**

The United States Faces Large and Complex Energy Challenges

Our expanding economy, growing population, and rising standard of living all depend on energy services. Current projections anticipate U.S. energy demands to increase by more than one-third by 2030, with electricity demand alone rising by more than 40 percent (EIA, 2006). At work and at home, we continue to rely on more and more energy-consuming devices. At the same time, the country has entered a period of higher energy costs and limited supplies of natural gas, heating oil, and other fuels. These issues present many challenges:

Growing energy demand stresses current systems, drives up energy costs, and requires new investments. Events such as the Northeast electricity blackout of August 2003 and Hurricanes Katrina and Rita in 2005 increased focus on energy reliability and its economic and human impacts. Transmission and pipeline systems are becoming overburdened in places. Overburdened systems limit the availability of low-cost electricity and fossil fuels, raise energy prices in or near congested areas, and potentially compromise energy system reliability. High fuel prices also contribute to higher electricity prices. In addition, our demand for natural gas to heat our homes, for industrial and business use, and for power generation is straining the available gas supply in North America and putting upward pressure on natural gas prices. Addressing these issues will require billions of dollars in investments in energy efficiency, new power plants, gas rigs, transmission lines, pipelines, and other infrastructure, notwithstanding the difficulty of building new energy infrastructure in dense urban and suburban areas. In the absence of investments in new or expanded capacity, existing facilities are being stretched to the point where system reliability is steadily eroding, and the ability to import lower cost energy into high-growth load areas is inhibited, potentially limiting economic expansion.

High fuel prices increase financial burdens on households and businesses and slow our economy. Many household budgets are being strained by higher energy costs, leaving less money available for other household purchases and needs. This burden is particularly harmful for low-income households. Higher energy bills for industry can reduce the nation's economic competitiveness and place U.S. jobs at risk.

Growing energy demand challenges attainment of clean air and other public health and environmental goals. Energy demand continues to grow at the same time that national and state regulations are being implemented to limit the emission of air pollutants, such as sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury, to protect public health and the environment. In addition, emissions of greenhouse gases continue to increase.

Uncertainties in future prices and regulations raise questions about new investments. New infrastructure is being planned in the face of uncertainties about future energy prices. For example, high natural gas prices and uncertainty about greenhouse gas and other environmental regulations, impede investment decisions on new energy supply options.

Our energy system is vulnerable to disruptions in energy supply and delivery. Natural disasters such as the hurricanes of 2005 exposed the vulnerability of the U.S. energy system to major disruptions, which have significant impacts on energy prices and service reliability. In response, national security concerns suggest that we should use fossil fuel energy more efficiently, increase supply diversity, and decrease the vulnerability of domestic infrastructure to natural disasters.

Energy Efficiency Can Be a Beneficial Resource in Our Energy Systems

Greater investment in energy efficiency can help us tackle these challenges. Energy efficiency is already a key component in the nation's energy resource mix in many parts of the country. Utilities, states, and others across the United States have decades of experience in delivering energy efficiency to their customers. These programs can provide valuable models, upon which more states,

Benefits of Energy Efficiency

Lower energy bills, greater customer control, and greater customer satisfaction. Well-designed energy efficiency programs can provide opportunities for customers of all types to adopt energy savings measures that can improve their comfort and level of service, while reducing their energy bills.[6] These programs can help customers make sound energy use decisions, increase control over their energy bills, and empower them to manage their energy usage. Customers are experiencing savings of 5, 10, 20, or 30 percent, depending upon the customer, program, and average bill. Offering these programs can also lead to greater customer satisfaction with the service provider.

Lower cost than supplying new generation only from new power plants. In some states, well-designed energy efficiency programs are saving energy at an average cost of about one-half of the typical cost of new power sources and about one-third of the cost of natural gas supply (EIA, 2006).[7] When integrated into a long-term energy resource plan, energy efficiency programs could help defer investments in new plants and lower the total cost of delivering electricity.

Modular and quick to deploy. Energy efficiency programs can be ramped up over a period of one to three years to deliver sizable savings. These programs can also be targeted to congested areas with high prices to bring relief where it might be difficult to deliver new supply in the near term.

Significant energy savings. Well-designed energy efficiency programs are delivering annual energy savings on the order of 1 percent of electricity and natural gas sales.[8] These programs are helping to offset 20 to 50 percent of expected growth in energy demand in some areas without compromising the end users' activities and economic well-being (Nadel et al., 2004; EIA, 2006).

Environmental benefits. While reducing customers' energy bills, cost-effective energy efficiency offers environmental benefits related to reduced demand such as lower air pollution, reduced greenhouse gas emissions, lower water use, and less environmental damage from fossil fuel extraction. Energy efficiency can be an attractive option for utilities in advance of requirements to reduce greenhouse gas emissions.

Economic development. Greater investment in energy efficiency helps build jobs and improve state economies. Energy efficiency users often redirect their bill savings toward other activities that increase local and national employment, with a higher employment impact than if the money had been spent to purchase energy (Kushler et al., 2005; NYSERDA, 2004). Many energy efficiency programs create construction and installation jobs, with multiplier impacts on employment and local economies. Local investments in energy efficiency can offset imports from out-of-state, improving the state balance of trade. Lastly, energy efficiency investments usually create long-lasting infrastructure changes to building, equipment and appliance stocks, creating long-term property improvements that deliver long-term economic value (Innovest, 2002).

Energy security. Energy efficiency reduces the level of U.S. per capita energy consumption, thus decreasing the vulnerability of the economy and individual consumers to energy price disruptions from natural disasters and attacks on domestic and international energy supplies and infrastructure. In addition, energy efficiency can be used to reduce the overall system peak demand or the peak demand in targeted load areas with limited generating or transport capability. Reducing peak demand improves system reliability and reduces the potential for unplanned brownouts or black-outs, which can have large adverse economic consequences.

utilities, and other organizations can build. Experience shows that energy efficiency programs can lower customer energy bills; cost less than, and help defer, new energy infrastructure; provide energy savings to consumers; improve the environment; and spur local economic development (see box on Benefits of Energy Efficiency). Significant opportunities for energy efficiency are likely to continue to be available at low costs in the future. State and regional studies have found that adoption of economically attractive, but as yet untapped, energy efficiency could yield more than 20 percent savings in total electricity demand nationwide by 2025. Depending on the underlying load growth, these savings could help cut load growth by half or more compared to current forecasts (Nadel et al., 2004; SWEEP, 2002; NEEP, 2005; NWPCC, 2005; WGA, 2006). Similarly, savings from direct use of natural gas could provide a 50 percent or greater reduction in natural gas demand growth (Nadel et al., 2004).

Capturing this energy efficiency resource would offer substantial economic and environmental benefits across the country. Widespread application of energy efficiency programs that already exist in some regions could deliver a large part of these potential savings.[9] Extrapolating the results from existing programs to the entire country would yield annual energy bill savings of nearly $20 billion, with net societal benefits of more than $250 billion over the next 10 to 15 years. This scenario could defer the need for 20,000 megawatts (MW), or 40 new 500-MW power plants, as well as reduce U.S. emissions from energy production and use by more than 200 million tons of carbon dioxide (CO_2), 50,000 tons of SO_2, and 40,000 tons of NO_x annually.[10] These significant economic and environmental benefits can be achieved relatively quickly because energy efficiency programs can be developed and implemented within several years.

Additional policies and programs are required to help capture these potential benefits and address our substantial underinvestment in energy efficiency as a nation. An important indicator of this underinvestment is that the level of funding across the country for organized efficiency programs is currently less than $2 billion per year while it would require about 4 times today's funding levels to achieve the economic and environment benefits presented above.[11, 12]

The current underinvestment in energy efficiency is due to a number of well-recognized barriers, including some of the regulatory policies that govern electric and natural gas utilities. These barriers include:

- *Market barriers,* such as the well-known "split-incentive" barrier, which limits home builders' and commercial developers' motivation to invest in energy efficiency for new buildings because they do not pay the energy bill; and the transaction cost barrier, which chronically affects individual consumer and small business decision-making.
- *Customer barriers,* such as lack of information on energy saving opportunities, lack of awareness of how energy efficiency programs make investments easier, and lack of funding to invest in energy efficiency.
- *Public policy barriers,* which can present prohibitive disincentives for utility support and investment in energy efficiency in many cases.
- *Utility, state, and regional planning barriers,* which do not allow energy efficiency to compete with supply-side resources in energy planning.
- *Energy efficiency program barriers,* which limit investment due to lack of knowledge about the most effective and cost-effective energy efficiency program portfolios, programs for overcoming common marketplace barriers to energy efficiency, or available technologies.

While a number of energy efficiency policies and programs contribute to addressing these barriers, such as building codes, appliance standards, and state government leadership programs, organized energy efficiency programs provide an important opportunity to deliver greater energy efficiency in the homes, buildings, and facilities that already exist today and that will consume the majority of the energy used in these sectors for years to come.

The Leadership Group and National Action Plan for Energy Efficiency

Recognizing that energy efficiency remains a critically underutilized resource in the nation's energy portfolio, more than 50 leading electric and gas utilities, state utility commissioners, state air and energy agencies, energy service providers, energy consumers, and energy efficiency and consumer advocates have formed a Leadership Group, together with the U.S. Department of Energy (DOE) and the U.S. Environmental Protection Agency (EPA), to address the issue. The goal of this group is to create a sustainable, aggressive national commitment to energy efficiency through gas and electric utilities, utility regulators, and partner organizations. The Leadership Group recognizes that utilities and regulators play critical roles in bringing energy efficiency programs to their communities and that success requires the joint efforts of customers, utilities, regulators, states, and other partner organizations.

Under co-chairs Diane Munns (Member of the Iowa Utilities Board and President of the National Association of Regulatory Utility Commissioners) and Jim Rogers (President and Chief Executive Officer of Duke Energy), the Leadership Group members (see Table ES-1) have developed the National Action Plan for Energy Efficiency Report, which:

- Identifies key barriers limiting greater investment in energy efficiency.
- Reviews sound business practices for removing these barriers and improving the acceptance and use of energy efficiency relative to energy supply options.
- Outlines recommendations and options for overcoming these barriers.

The members of the Leadership Group have agreed to pursue these recommendations and consider these options through their own actions, where appropriate, and to support energy efficiency initiatives by other industry members and stakeholders.

Recommendations

The National Action Plan for Energy Efficiency is a call to action to utilities, state utility regulators, consumer advocates, consumers, businesses, other state officials, and other stakeholders to create an aggressive, sustainable national commitment to energy efficiency.[1] The Action Plan offers the following recommendations as ways to overcome barriers that have limited greater investment in energy efficiency for customers of electric and gas utilities in many parts of the country. The following recommendations are based on the policies, practices, and efforts of leading organizations across the country. For each recommendation, a number of options are available to be pursued based on regional, state, and utility circumstances (see also Figure ES-2).

Recognize energy efficiency as a high-priority energy resource. Energy efficiency has not been consistently viewed as a meaningful or dependable resource compared to new supply options, regardless of its demonstrated contributions to meeting load growth.[13] Recognizing energy efficiency as a high-priority energy resource is an important step in efforts to capture the benefits it offers and lower the overall cost of energy services to customers. Based on jurisdictional objectives, energy efficiency can be incorporated into resource plans to account for the long-term benefits from energy savings, capacity savings, potential reductions of air pollutants and greenhouse gases, as well as other benefits. The explicit integration of energy efficiency resources into the formalized resource planning processes that exist at regional, state, and utility levels can help establish the rationale for energy efficiency funding levels and for properly valuing and balancing the benefits. In some jurisdictions, these existing planning processes might need to be adapted or even created to meaningfully incorporate energy efficiency resources into resource planning. Some states have recognized energy efficiency as the resource of first priority due to its broad benefits.

Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource. Energy efficiency programs are most successful and provide the greatest benefits to stakeholders when appropriate policies are established and maintained over the long-term. Confidence in long-term stability of the program will help maintain energy efficiency as a dependable resource compared to supply-side resources, deferring or even avoiding the need for other infrastructure investments, and maintain customer awareness and support. Some steps might include assessing the long-term potential for cost-effective energy efficiency within a region (i.e., the energy efficiency that can be delivered cost-effectively through proven programs for each customer class within a planning horizon); examining the role for cutting-edge initiatives and technologies; establishing the cost of supply-side options versus energy efficiency; establishing robust measurement and verification (M&V) procedures; and providing for routine updates to information on energy efficiency potential and key costs.

Broadly communicate the benefits of and opportunities for energy efficiency. Experience shows that energy efficiency programs help customers save money and contribute to lower cost energy systems. But these benefits are not fully documented nor recognized by customers, utilities, regulators, or policy-makers. More effort is needed to establish the business case for energy efficiency for all decision-makers and to show how a well-designed approach to energy efficiency can benefit customers, utilities, and society by (1) reducing customers' bills over time, (2) fostering financially healthy utilities (e.g., return on equity, earnings per share, and debt coverage ratios unaffected), and (3) contributing to positive societal net benefits overall. Effort is also necessary to educate key stakeholders that although energy efficiency can be an important low-cost resource to integrate into the energy mix, it does require funding just as a new power plant requires funding. Further, education is necessary on the impact that energy efficiency programs can have in concert with other energy efficiency policies such as building codes, appliance standards, and tax incentives.

Promote sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective. Energy efficiency programs require consistent and long-term funding to effectively compete with energy supply options. Efforts are necessary to establish this consistent long-term funding. A variety of mechanisms have been, and can be, used based on state, utility, and other stakeholder interests. It is important to ensure that the efficiency programs' providers have sufficient long-term funding to recover program costs and implement the energy efficiency measures that have been demonstrated to be available and cost effective. A number of states are now linking program funding to the achievement of energy savings.

Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments. Successful energy efficiency programs would be promoted by aligning utility incentives in a manner that encourages the delivery of energy efficiency as part of a balanced portfolio of supply, demand, and transmission investments. Historically, regulatory policies governing utilities have more commonly compensated utilities for building infrastructure (e.g., power plants, transmission lines, pipelines) and selling energy, while discouraging energy efficiency, even when the energy-saving measures might cost less. Within the existing regulatory processes, utilities, regulators, and stakeholders have a number of opportunities to create the incentives for energy efficiency investments by utilities and customers. A variety of mechanisms have already been used. For example, parties can decide to provide incentives for energy efficiency similar to utility incentives for new infrastructure investments, provide rewards for prudent management of energy efficiency programs, and incorporate energy efficiency as an important area of consideration within rate design. Rate design offers

Figure ES-2. National Action Plan for Energy Efficiency Recommendations & Options

Recognize energy efficiency as a high priority energy resource.

Options to consider:

- Establishing policies to establish energy efficiency as a priority resource.
- Integrating energy efficiency into utility, state, and regional resource planning activities.
- Quantifying and establishing the value of energy efficiency, considering energy savings, capacity savings, and environmental benefits, as appropriate.

Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource.

Options to consider:

- Establishing appropriate cost-effectiveness tests for a portfolio of programs to reflect the long-term benefits of energy efficiency.
- Establishing the potential for long-term, cost-effective energy efficiency savings by customer class through proven programs, innovative initiatives, and cutting-edge technologies.
- Establishing funding requirements for delivering long-term, cost-effective energy efficiency.
- Developing long-term energy saving goals as part of energy planning processes.
- Developing robust measurement and verification (M&V) procedures.
- Designating which organization(s) is responsible for administering the energy efficiency programs.
- Providing for frequent updates to energy resource plans to accommodate new information and technology.

Broadly communicate the benefits of and opportunities for energy efficiency.

Options to consider:

- Establishing and educating stakeholders on the business case for energy efficiency at the state, utility, and other appropriate level addressing relevant customer, utility, and societal perspectives.
- Communicating the role of energy efficiency in lowering customer energy bills and system costs and risks over time.
- Communicating the role of building codes, appliance standards, and tax and other incentives.

Provide sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective.

Options to consider:

- Deciding on and committing to a consistent way for program administrators to recover energy efficiency costs in a timely manner.
- Establishing funding mechanisms for energy efficiency from among the available options such as revenue requirement or resource procurement funding, system benefits charges, rate-basing, shared-savings, incentive mechanisms, etc.
- Establishing funding for multi-year periods.

Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments.

Options to consider:

- Addressing the typical utility throughput incentive and removing other regulatory and management disincentives to energy efficiency.
- Providing utility incentives for the successful management of energy efficiency programs.
- Including the impact on adoption of energy efficiency as one of the goals of retail rate design, recognizing that it must be balanced with other objectives.
- Eliminating rate designs that discourage energy efficiency by not increasing costs as customers consume more electricity or natural gas.
- Adopting rate designs that encourage energy efficiency by considering the unique characteristics of each customer class and including partnering tariffs with other mechanisms that encourage energy efficiency, such as benefit sharing programs and on-bill financing.

opportunities to encourage customers to invest in efficiency where they find it to be cost effective and participate in new programs that provide innovative technologies (e.g., smart meters) to help customers control their energy costs.

National Action Plan for Energy Efficiency: Next Steps

In summer 2006, members of the Leadership Group of the National Action Plan on Energy Efficiency are announcing a number of specific activities and initiatives to formalize and reinforce their commitments to energy efficiency as a resource. To assist the Leadership Group and others in making and fulfilling their commitments, a number of tools and resources have been developed:

National Action Plan for Energy Efficiency Report. This report details the key barriers to energy efficiency in resource planning, utility incentive mechanisms, rate design, and the design and implementation of energy efficiency programs. It also reviews and presents a variety of policy and program solutions that have been used to overcome these barriers as well as the pros and cons for many of these approaches.

Energy Efficiency Benefits Calculator. This calculator can be used to help educate stakeholders on the broad benefits of energy efficiency. It provides a simplified framework to demonstrate the business case for energy efficiency from the perspective of the consumer, the utility, and society. It has been used to explore the benefits of energy efficiency program investments under a range of utility structures, policy mechanisms, and energy growth scenarios. The calculator can be adapted and applied to other scenarios.

Experts and Resource Materials on Energy Efficiency. A number of educational presentations on the potential for energy efficiency and various policies available for pursuing the recommendations of the Action Plan will be developed. In addition, lists of policy and program experts in energy efficiency and the various policies available for pursuing the recommendations of the Action Plan will be developed. These lists will be drawn from utilities, state utility regulators, state energy offices, third-party energy efficiency program administrators, consumer advocacy organizations, ESCOs, and others. These resources will be available in fall 2006.

DOE and EPA are continuing to facilitate the work of the Leadership Group and the National Action Plan for Energy Efficiency. During winter 2006–2007, the Leadership Group plans to report on its progress and identify next steps for the Action Plan.

Table ES-1. Members of the National Action Plan for Energy Efficiency

Co-Chairs		
Diane Munns	Member President	Iowa Utilities Board National Association of Regulatory Utility Commissioners
Jim Rogers	President and Chief Executive Officer	Duke Energy
Leadership Group		
Barry Abramson	Senior Vice President	Servidyne Systems, LLC
Angela S. Beehler	Director of Energy Regulation	Wal-Mart Stores, Inc.
Bruce Braine	Vice President, Strategic Policy Analysis	American Electric Power
Jeff Burks	Director of Environmental Sustainability	PNM Resources
Kateri Callahan	President	Alliance to Save Energy
Glenn Cannon	General Manager	Waverly Light and Power
Jorge Carrasco	Superintendent	Seattle City Light
Lonnie Carter	President and Chief Executive Officer	Santee Cooper
Mark Case	Vice President for Business Performance	Baltimore Gas and Electric
Gary Connett	Manager of Resource Planning and Member Services	Great River Energy
Larry Downes	Chairman and Chief Executive Officer	New Jersey Natural Gas (New Jersey Resources Corporation)
Roger Duncan	Deputy General Manager, Distributed Energy Services	Austin Energy
Angelo Esposito	Senior Vice President, Energy Services and Technology	New York Power Authority
William Flynn	Chairman	New York State Public Service Commission
Jeanne Fox	President	New Jersey Board of Public Utilities
Anne George	Commissioner	Connecticut Department of Public Utility Control
Dian Grueneich	Commissioner	California Public Utilities Commission
Blair Hamilton	Policy Director	Vermont Energy Investment Corporation
Leonard Haynes	Executive Vice President, Supply Technologies, Renewables, and Demand Side Planning	Southern Company
Mary Healey	Consumer Counsel for the State of Connecticut	Connecticut Consumer Counsel
Helen Howes	Vice President, Environment, Health and Safety	Exelon
Chris James	Air Director	Connecticut Department of Environmental Protection
Ruth Kinzey	Director of Corporate Communications	Food Lion
Peter Lendrum	Vice President, Sales and Marketing	Entergy Corporation
Rick Leuthauser	Manager of Energy Efficiency	MidAmerican Energy Company
Mark McGahey	Manager	Tristate Generation and Transmission Association, Inc.
Janine Migden-Ostrander	Consumers' Counsel	Office of the Ohio Consumers' Counsel
Richard Morgan	Commissioner	District of Columbia Public Service Commission
Brock Nicholson	Deputy Director, Division of Air Quality	North Carolina Air Office
Pat Oshie	Commissioner	Washington Utilities and Transportation Commission
Douglas Petitt	Vice President, Government Affairs	Vectren Corporation

Bill Prindle	Deputy Director	American Council for an Energy-Efficient Economy
Phyllis Reha	Commissioner	Minnesota Public Utilities Commission
Roland Risser	Director, Customer Energy Efficiency	Pacific Gas and Electric
Gene Rodrigues	Director, Energy Efficiency	Southern California Edison
Art Rosenfeld	Commissioner	California Energy Commission
Jan Schori	General Manager	Sacramento Municipal Utility District
Larry Shirley	Division Director	North Carolina Energy Office
Michael Shore	Senior Air Policy Analyst	Environmental Defense
Gordon Slack	Energy Business Director	The Dow Chemical Company
Deb Sundin	Director, Business Product Marketing	Xcel Energy
Dub Taylor	Director	Texas State Energy Conservation Office
Paul von Paumgartten	Director, Energy and Environmental Affairs	Johnson Controls
Brenna Walraven	Executive Director, National Property Management	USAA Realty Company
Devra Wang	Director, California Energy Program	Natural Resources Defense Council
Steve Ward	Public Advocate	State of Maine
Mike Weedall	Vice President, Energy Efficiency	Bonneville Power Administration
Tom Welch	Vice President, External Affairs	PJM Interconnection
Jim West	Manager of *energy right* & Green Power Switch	Tennessee Valley Authority
Henry Yoshimura	Manager, Demand Response	ISO New England Inc.

Observers

James W. (Jay) Brew	Counsel	Steel Manufacturers Association
Roger Cooper	Executive Vice President, Policy and Planning	American Gas Association
Dan Delurey	Executive Director	Demand Response Coordinating Committee
Roger Fragua	Deputy Director	Council of Energy Resource Tribes
Jeff Genzer	General Counsel	National Association of State Energy Officials
Donald Gilligan	President	National Association of Energy Service Companies
Chuck Gray	Executive Director	National Association of Regulatory Utility Commissioners
John Holt	Senior Manager of Generation and Fuel	National Rural Electric Cooperative Association
Joseph Mattingly	Vice President, Secretary and General Counsel	Gas Appliance Manufacturers Association
Kenneth Mentzer	President and Chief Executive Officer	North American Insulation Manufacturers Association
Christina Mudd	Executive Director	National Council on Electricity Policy
Ellen Petrill	Director, Public/Private Partnerships	Electric Power Research Institute
Alan Richardson	President and Chief Executive Officer	American Public Power Association
Steve Rosenstock	Manager, Energy Solutions	Edison Electric Institute
Diane Shea	Executive Director	National Association of State Energy Officials
Rick Tempchin	Director, Retail Distribution Policy	Edison Electric Institute
Mark Wolfe	Executive Director	Energy Programs Consortium

Notes

1 Energy efficiency refers to using less energy to provide the same or improved level of service to the energy consumer in an economically efficient way. The term energy efficiency as used here includes using less energy at any time, including at times of peak demand through demand response and peak shaving efforts.

2 Addressing transportation-related energy use is also an important challenge as energy demand in this sector continues to increase and oil prices hit historical highs. However, transportation issues are outside the scope of this effort, which is focused only on electricity and natural gas systems.

3 This effort is focused on energy efficiency for regulated energy forms. Energy efficiency for unregulated energy forms, such as fuel oil for example, is closely related in terms of actions in buildings, but is quite different in terms of how policy can promote investments.

4 A utility is broadly defined as an organization that delivers electric and gas utility services to end users, including, but not limited to, investor-owned, publicly-owned, cooperatively-owned, and third-party energy efficiency utilities.

5 Many energy efficiency programs have an average life cycle cost of $0.03/kilowatt-hour (kWh) saved, which is 50 to 75 percent of the typical cost of new power sources (ACEEE, 2004; EIA, 2006). The cost of energy efficiency programs varies by program and can include higher cost programs and options with lower costs to a utility such as modifying rate designs.

6 See Chapter 6: Energy Efficiency Program Best Practices for more information on leading programs.

7 Data refer to EIA 2006 new power costs and gas prices in 2015 compared to electric and gas program costs based on leading energy efficiency programs, many of which are discussed in Chapter 6: Energy Efficiency Program Best Practices.

8 Based on leading energy efficiency programs, many of which are discussed in Chapter 6: Energy Efficiency Program Best Practices.

9 These estimates are based on assumptions of average program spending levels by utilities or other program administrators, with conservatively high numbers for the cost of energy efficiency programs. See highlights of some of these programs in Chapter 6: Energy Efficiency Program Best Practices, Tables 6-1 and 6-2.

10 These economic and environmental savings estimates are extrapolations of the results from regional program to a national scope. Actual savings at the regional level vary based on a number of factors. For these estimates, avoided capacity value is based on peak load reductions de-rated for reductions that do not result in savings of capital investments. Emissions savings are based on a marginal on-peak generation fuel of natural gas and marginal off-peak fuel of coal; with the on-peak period capacity requirement double that of the annual average. These assumptions vary by region based upon situation-specific variables. Reductions in capped emissions might reduce the cost of compliance.

11 This estimate of the funding required assumes 2 percent of revenues across electric utilities and 0.5 percent across gas utilities. The estimate also assumes that energy efficiency is delivered at a total cost (utility and participant) of $0.04 per kWh and $3 per million British thermal units (MMBtu), which are higher than the costs of many of today's programs.

12 This estimate is provided as an indicator of underinvestment and is not intended to establish a national funding target. Appropriate funding levels for programs should be established at the regional, state, or utility level. In addition, energy efficiency investments by customers, businesses, industry, and government also contribute to the larger economic and environment benefits of energy efficiency.

13 One example of energy efficiency's ability to meet load growth is the Northwest Power Planning Council's Fifth Power Plan which uses energy conservation and efficiency to meet a targeted 700 MW of forecasted capacity between 2005 and 2009 (NWPCC, 2005).

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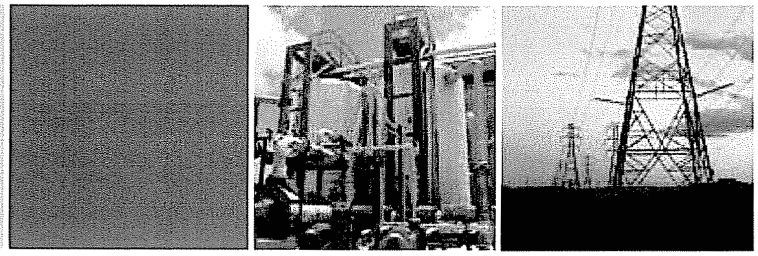
1: Introduction and Background



Overview

We currently face a number of challenges in securing affordable, reliable, secure, and clean energy to meet our nation's growing energy demand. Demand is outpacing supply, costs are rising, and concerns for the environment are growing.

Improving the energy efficiency[1] of our homes, businesses, schools, governments, and industries – which consume more than 70 percent of the energy used in the country—is one of the most constructive, cost-effective ways to address these challenges. Greater investment in energy efficiency programs across the country could help meet our growing electricity and natural gas demand, save customers billions of dollars on their energy bills, reduce emissions of air pollutants and greenhouse gases, and contribute to a more secure, reliable, and low-cost energy system. Despite this opportunity, energy efficiency remains an under-utilized resource in the nation's energy portfolio.

There are many ways to increase investment in cost-effective energy efficiency including developing building codes and appliance standards, implementing government leadership efforts, and educating the public through programs such as ENERGY STAR®.[2] Another important area is greater investment in organized energy efficiency programs that are managed by electric and natural gas providers, states, or third-party administrators. Energy efficiency programs already contribute to the energy mix in many parts of the country and have delivered significant savings and other benefits. Despite the benefits, these programs face hurdles in many areas of the country. Identifying and removing these barriers is a focus of this effort.

October 2005
Excerpt from Letter From Co-Chairs to the National Action Plan for Energy Efficiency Leadership Group

Energy efficiency is a critically under-utilized resource in the nation's energy portfolio. Those states and utilities that have made significant investments in energy efficiency have lowered the growth for energy demand and moderated their energy costs. However, many hurdles remain that block broader investments in cost-effective energy efficiency.

That is why we have agreed to chair the Energy Efficiency Action Plan. It is our hope that with the help of leading organizations like yours, we will identify and overcome these hurdles.

Through this Action Plan, we intend to identify the major barriers currently limiting greater investment by utilities in energy efficiency. We will develop a series of business cases that will demonstrate the value and contributions of energy efficiency and explain how to remove these barriers (including regulatory and market challenges). These business cases, along with descriptions of leading energy efficiency programs, will build upon practices already in place across the country.

Diane Munns
President, NARUC
Member, Iowa Utilities Board

Jim Rogers
President and CEO
Duke Energy

To drive a sustainable, aggressive national commitment to energy efficiency through gas and electric utilities, utility regulators, and partner organizations, more than 50 leading organizations joined together to develop this National Action Plan for Energy Efficiency. The Action Plan is co-chaired by Diane Munns, Member of the Iowa

[1] Energy efficiency refers to using less energy to provide the same or improved level of service to the energy consumer in an economically efficient way. The term energy efficiency as used here includes using less energy at any time, including at times of peak demand through demand response and peak shaving efforts.

[2] See EPA 2006 for a description of a broad set of policies being used at the state level to advance energy efficiency.

Utilities Board and President of the National Association of Regulatory Utility Commissioners, and Jim Rogers, President and Chief Executive Officer of Duke Energy. The Leadership Group includes representatives from a broad set of stakeholders, including electric and gas utilities, state utility commissioners, state air and energy agencies, energy service providers, energy consumers, and energy efficiency and consumer advocates. This effort is facilitated by the U.S. Department of Energy (DOE) and the U.S. Environmental Protection Agency (EPA). The National Action Plan for Energy Efficiency:

- Identifies key barriers limiting greater investment in energy efficiency,
- Reviews sound business practices for removing these barriers and improving the acceptance and use of energy efficiency relative to energy supply options, and
- Outlines recommendations and options for overcoming these barriers.

In addition, members of the Leadership Group are committing to act within their own organizations and spheres of influence to increase attention and investment in energy efficiency. Greater investment in energy efficiency cannot happen based on the work of one individual or organization alone. The Leadership Group recognizes that the joint efforts of the customer, utility, regulator, and partner organizations are needed to reinvigorate and increase the use of energy efficiency in America. As energy experts, utilities may be in a unique position to play a leadership role.

The rest of this introduction chapter establishes why now is the time to increase our investment in energy efficiency, outlines the approach taken in the National Action Plan for Energy Efficiency, and explains the structure of this report.

Why Focus on Energy Efficiency?

Energy Challenges

We currently face multiple challenges in providing affordable, clean, and reliable energy in today's complex energy markets:

- *Electricity demand* continues to rise. Given current energy consumption and demographic trends, DOE projects that U.S. energy consumption will increase by more than one-third by the year 2025. Electric power consumption is expected to increase by almost 40 percent, and total fossil fuel use is projected to increase similarly (EIA, 2005). At work and at home, we continue to rely on more energy-consuming devices. This growth in demand stresses current systems and requires substantial new investments in system expansions.
- *High energy prices.* Our demand for natural gas to heat our homes, for industrial and business uses, and for power plants is straining the available gas supply in North America and putting upward pressure on natural gas prices. Many household budgets are being strained by higher energy costs, leaving less money available for other household purchases and needs; this situation is particularly harmful for low-income households. Consumers are looking for ways to manage their energy bills. Higher energy bills for industry are reducing the nation's economic competitiveness and placing U.S. jobs at risk. Higher energy prices also raise the financial risk associated with the development of new natural gas-fired power plants, which had been expected to make up more than 60 percent of capacity additions over the next 20 years (EIA, 2005). Coal prices are also increasing and contributing to higher electricity costs.
- *Energy system reliability.* Events such as the Northeast electricity blackout of August 2003 and Hurricanes Katrina and Rita in 2005 highlighted the vulnerability of our energy system to disruptions. This led to an

increased focus on energy reliability and its economic and human impacts, as well as national security concerns using fossil fuel more efficiently and increasing energy supply diversity.

- *Transmission systems* are overburdened in some places, limiting the flow of economical generation and, in some cases, shrinking reserve margins of the electricity grid to inappropriately small levels. This situation can cause reliability problems and high electricity prices in or near congested areas.

- *Environmental concerns.* Energy demand continues to grow as national and state regulations are being implemented to significantly limit the emissions of air pollutants, such as sulfur dioxide (SO_2), nitrogen oxides (NO_X), and mercury, to protect public health and the environment. Many existing base load generation plants are aging and significant retrofits are needed to ensure old generating units meet these emissions regulations. In addition, emissions of greenhouse gases continue to increase.

Addressing these issues will require billions of dollars in investments in new power plants, gas rigs, transmission lines, pipelines, and other infrastructure, notwithstanding the difficulty of building new energy infrastructure in dense urban and suburban locations even with current energy efficiency investment. The decisions we make now regarding our energy supply and demand can either help us deal with these challenges more effectively or complicate our ability to secure a more stable, economical energy future.

Benefits of Energy Efficiency

Greater investment in energy efficiency can help us tackle these challenges. Energy efficiency is already a key component in the nation's energy resource mix in many parts of the country, and experience shows that energy efficiency programs can lower customer energy bills; cost less than, and help defer, new energy production; provide environmental benefits; and spur local economic development. Some of the major benefits of energy efficiency include:

- *Lower energy bills, greater customer control, and greater customer satisfaction.* Well-designed programs can provide opportunities for all customer classes to adopt energy savings measures and reduce their energy bills.[3] These programs can help customers make sound energy use decisions, increase control over their energy bills with savings of 5 to 30 percent, and empower them to manage their energy usage. Customers often express greater satisfaction with electricity and natural gas providers where energy efficiency is offered.

- *Lower cost than supplying new generation only from new power plants.* Well-designed energy efficiency programs are saving energy at an average cost of one-half of the typical cost of new power sources and about one-third of the cost of providing natural gas.[4] When integrated into a long-term energy resource plan, energy efficiency could help defer investments in new plants and lower the total energy system cost.

- *Modular and quick to deploy.* Energy efficiency programs can be ramped up over a period of one to three years to deliver sizable savings. These programs can also be targeted to congested areas with high prices to bring relief where it might be difficult to deliver new supply in the near term.

- *Significant energy savings.* Well-designed energy efficiency programs are delivering energy savings each year on the order of 1 percent of total electric and natural gas sales.[5] These programs are helping to offset 20 to 50 percent of expected growth in energy

[3] See Chapter 6: Energy Efficiency Program Best Practices for more information on leading programs

[4] Based on new power costs and gas prices in 2015 (EIA, 2006) compared to electric and gas program costs based on leading energy programs, many of which are discussed in Chapter 6: Energy Efficiency Program Best Practices

[5] Based on leading energy efficiency programs, many of which are discussed in Chapter 6: Energy Efficiency Program Best Practices

demand in some areas without compromising the end users' activities and economic well-being (Nadel, et al., 2004; EIA, 2006).

- *Environmental benefits.* Cost-effective energy efficiency offers environmental benefits related to reduced demand, such as reduced air pollution and greenhouse gas emissions, lower water use, and less environmental damage from fossil fuel extraction. Energy efficiency is an attractive option for generation owners in advance of requirements to reduce greenhouse gas emissions.

- *Economic development.* Greater investment in energy efficiency helps build jobs and improve state economies. Energy efficiency users often redirect their bill savings toward other activities that increase local and national employment, with a higher employment impact than if the money had been spent to purchase energy (York and Kushler, 2005; NYSERDA, 2004). Many energy efficiency programs create construction and installation jobs, with multiplier impacts on other employment and local economies (Sedano et al., 2005). Local investments in energy efficiency can offset energy imports from out-of-state, improving the state balance of trade. Lastly, energy efficiency investments usually create long-lasting infrastructure changes to building, equipment and appliance stocks, creating long-term property improvements that deliver long-term economic value (Innovest, 2002).

- *Energy security.* Energy efficiency reduces the level of U.S. per capita energy consumption, thus decreasing the vulnerability of the economy and individual consumers to energy price disruptions from natural disasters and attacks upon domestic and international energy supplies and infrastructure.

Decades of Experience With Energy Efficiency

Utilities and their regulators began recognizing the potential benefits of improving efficiency and reducing demand in the 1970s and 1980s. These "demand-side management" (DSM) approaches meet increased demands for electricity or natural gas by managing the demand on the customer's side of the meter rather than increasing or acquiring more supplies. Planning processes, such as "least-cost planning" or "integrated resource planning," have been used to evaluate DSM programs on par with supply options and allow investment in DSM programs when they cost less than new supply options.

DSM program spending exceeded $2 billion a year (in 2005 dollars) in 1993 and 1994 (York and Kushler, 2005). In the late 1990s, funding for utility-sponsored energy efficiency was reduced in about half of the states due to changed regulatory structures and increased political and regulatory pressures to hold down electricity prices. This funding has partially recovered with new

Long Island Power Authority's (LIPA) Clean Energy Program Drives Economic Development, Customer Savings, and Environmental Quality Enhancements

LIPA started its Clean Energy Initiative in 1999 and has invested $229 million over the past 6 years. LIPA's portfolio of energy efficiency programs from 1999 to 2005 produced significant energy savings, emissions reductions and stimulated economic growth on Long Island:

- 296 megawatts (MW) peak demand savings
- 1,348 gigawatt-hours (GWh) cumulative savings
- Emissions reductions of:
  - Greater than 937,402 tons of carbon dioxide (CO_2)
  - Greater than 1,334 tons of NO_X
  - Greater than 4,298 tons of SO_2
- $275 million in customer bill savings and rebates
- $234 million increase in net economic output on Long Island
- 4,500 secondary jobs created

Source: LIPA, 2006

policies and funding mechanisms (see Figure 1-1) implemented to ensure that some level of cost-effective energy efficiency was pursued.

Notwithstanding the policy and regulatory changes that have affected energy efficiency program funding, wide scale, organized energy efficiency programs have now been operating for decades in certain parts of the country. These efforts have demonstrated the following:

- *Energy efficiency programs deliver significant savings.* In the mid-1990s, based on the high program funding levels of the early 1990s, electric utilities estimated program savings of 30 gigawatts (the output of about 100 medium-sized power plants) and more than 60 million megawatt-hours (MWh).
- *Energy efficiency programs can be used to meet a significant portion of expected load growth.* For example:
    - — The Pacific Northwest region has met 40 percent of its growth over the past two decades through energy efficiency programs (see Figure 1-2).
    - — California's energy efficiency goals, adopted in 2004 by the Public Utilities Commission, are to

Puget Sound Energy's (PSE) Resource Plan Includes Accelerated Conservation to Minimize Risks and Costs

PSE's 2002 and 2005 Integrated Resource Plans (IRPs) found that the accelerated development of energy efficiency minimizes both costs and risks. As a result, PSE significantly expanded its energy efficiency efforts. PSE is now on track to save 279 average MW (aMW) between 2006 and 2015, more than the company had saved between 1980 and 2004. The 279 aMW of energy efficiency represents nearly 10 percent of its forecasted 2015 sales.

Source: Puget Sound Energy, 2005

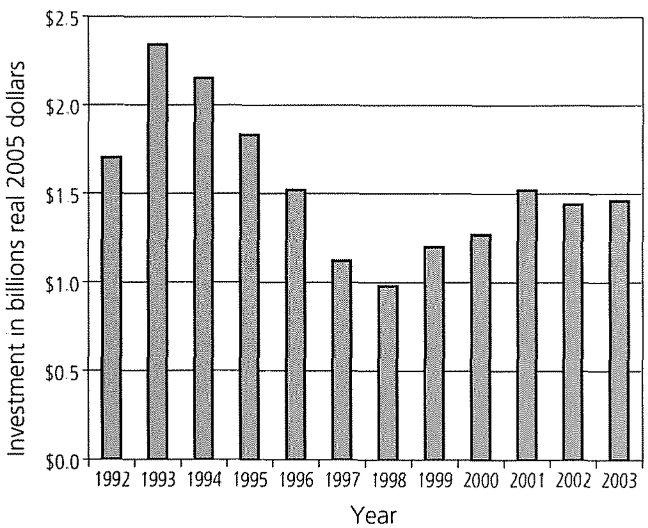
Connecticut's Energy Efficiency Programs Generate Savings of $550 Million in 2005

In 2005, the Connecticut Energy Efficiency Fund, managed by the Energy Conservation Management Board, invested $80 million in energy efficiency. This investment is expected to produce $550 million of bill savings to Connecticut electricity consumers. In addition, the 2005 programs, administered by Northeast Utilities and United Illuminating, resulted in:

- 126 MW peak demand reduction
- 4,398 GWh lifetime savings
- Emissions reductions of:
    - — Greater than 2.7 million tons of CO_2
    - — Greater than 1,702 tons of NO_X
    - — Greater than 4,616 tons of SO_2
- 1,000 non-utility jobs in the energy efficiency industry

Source: CECMB, 2006

Figure 1-1: Energy Efficiency Spending Has Declined



Source: Data derived from ACEEE 2005 Scorecard (York and Kushler, 2005) adjusted for inflation using U.S. Department of Labor Bureau of Labor Statistics Inflation Calculator use energy efficiency to displace more than half of future electricity load growth and avoid the need to build three large (500 MW) power plants.

- *Energy efficiency is being delivered cost-competitively with new supply.* Programs across the country are demonstrating that energy efficiency can be delivered at a cost of 2 to 4 cents per kilowatt-hour (kWh) and a cost of \$1.30 to \$2.00 per lifetime million British thermal units (MMBtu) saved.

- *Energy efficiency can be targeted to reduce peak demand.* A variety of programs address the peak demand of different customer classes, lowering the strain on existing supply assets (e.g., pipeline capacity, transmission and distribution capacity, and power plant capability), allowing energy delivery companies to better utilize existing assets and deferring new capital investments.

- *Proven, cost-effective program models are available to build upon.* These program models are available for almost every customer class, both gas and electric.

Southern California Edison's (SCE) Energy Efficiency Investments Provide Economic and Environmental Savings

SCE's comprehensive portfolio of energy efficiency programs for 2006 through 2008 will produce:

- 3 percent average bill reduction by 2010
- 3.5 billion kWh of energy savings
- 888 MW of demand savings
- 20.5 million tons of CO_2 emission reductions
- 5.5 million tons of NO_X emission reductions
- Energy saved at a cost of less than 4.1 cents/kWh

Source: *Southern California Edison*, 2006

New York State's Aggressive Energy Efficiency Programs Help Power the Economy As Well As Reduce Energy Costs

New York State Energy Research and Development Authority's (NYSERDA's) portfolio of energy efficiency programs for the period from 1999 to 2005 produced significant energy savings, as well as stimulated economic growth and jobs, and reduced energy prices in the state:

- 19 billion kWh/year of energy savings
- 4,166 added jobs/year (created/retained) from 1999 to 2017
- \$244 million/year in added total economic growth from 1999 to 2017
- \$94.5 million in energy price savings over three years

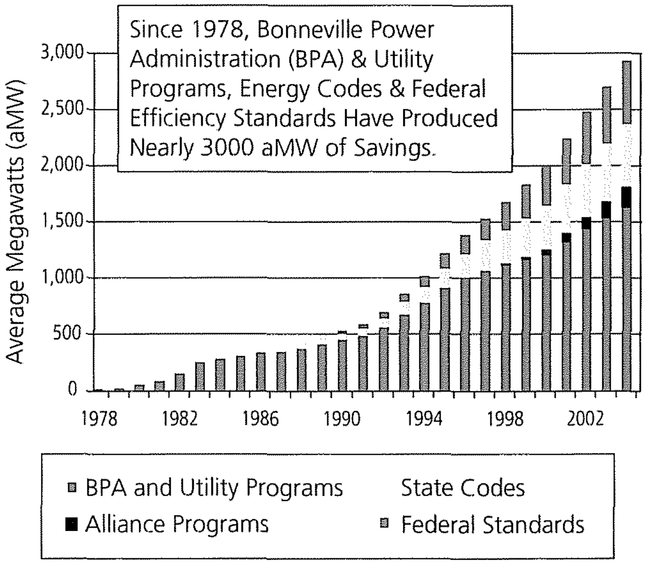
Source: NYSERDA, 2006

National Case for Energy Efficiency

Improving the energy efficiency of homes, businesses, schools, governments, and industries—which consume more than 70 percent of the energy used in the country — is one of the most constructive, cost-effective ways to address the nation's energy challenges. Many of these buildings and facilities are decades old and will consume the majority of the energy to be used in these sectors for years to come. State and regional studies have found that adoption of economically attractive, but as yet untapped, energy efficiency could yield more than 20 percent savings in total electricity demand nationwide by 2025. Depending on the underlying load growth, these savings could help cut load growth by half or more compared to current forecasts (Nadel et al., 2004; SWEEP, 2002; NEEP, 2005; NWPCC, 2005; WGA, 2006). Similarly, energy efficiency targeted at direct natural gas use could lower natural gas demand growth by 50 percent (Nadel et al., 2004). Furthermore, studies also show that significant reductions in energy consumption can be achieved quickly (Callahan, 2006) and at low costs for many years to come.

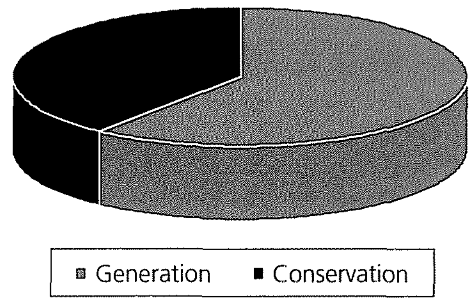
Figure 1-2: Energy Efficiency Has Been a Resource in the Pacific Northwest for the Past Two Decades

Pacific Northwest Energy Efficiency Achievements 1978 - 2004



Source: Eckman, 2005

Energy Efficiency Met Nearly 40 Percent of Pacific Northwest Regional Firm Sales Growth Between 1980 to 2003



Capturing this energy efficiency resource would offer substantial economic and environmental benefits across the country. Widespread application of energy efficiency programs that already exist in some regions[6] could deliver a large part of these potential savings. Extrapolating the results from existing programs to the entire country would yield over the next 10 to 15 years[7]:

- Energy bill savings of nearly $20 billion annually.
- Net societal benefits of more than $250 billion.[8]
- Avoided need for 20,000 MW (40 new 500 MW-power plants).
- Avoided annual air emissions of more than 200 million tons of CO_2, 50,000 tons of SO_2, and 40,000 tons of NO_X.

These benefits illustrate the magnitude of the benefits cost-effective energy efficiency offers. They are estimated based on (1) assumptions of average program spending levels by utilities or other program administrators that currently sponsor energy efficiency programs and (2) conservatively high estimates for the cost of the energy efficiency programs themselves (see Table 1-1).[9] They are not meant as a prescription; there are differences in opportunities and costs for energy efficiency that need to be addressed at the regional, state, and utility level to design and operate effective programs.

6 See highlights of some of these programs in Chapter 6: Energy Efficiency Program Best Practices, Tables 6-1 and 6-2.

7 These economic and environmental savings estimates extrapolate the results from regional programs to a national scope. Actual savings at the regional level vary based on a number of factors. For these estimates, avoided capacity value is based on peak load reductions de-rated for reductions that do not result in savings of capital investments. Emission savings are based on a marginal on-peak generation fuel of natural gas and marginal off-peak fuel of coal, with the on-peak period capacity requirement double that of the annual average. These assumptions vary by region based upon situation-specific variables. Reductions in capped emissions might reduce the cost of compliance.

8 Net present value (NPV) assuming 5 percent discount rate.

9 This estimate of the funding required assumes 2 percent of revenues across electric utilities and 0.5 percent across gas utilities. The estimate also assumes that energy efficiency is delivered at a total cost (utility and participant) of $0.04 per kWh and $3 per MMBtu, which are higher than the costs of many of today's programs.

Table 1-1. Summary of Benefits for National Energy Efficiency Efforts

Program Cost	Electric	Natural Gas	Total
Utility Program Spending (% of utility revenue)	2.0%	0.5%	
Total Cost of Efficiency (customer & utility)	$35/MWh	$3/MMBtu	
Cost of Efficiency (customer)	$15/MWh	$2/MMBtu	
Average Annual Cost of Efficiency ($MM)	$6,800	$1,200	
Total Cost of Efficiency (NPV, $MM)	$140,000	$25,000	$165,000
Efficiency Spending - Customer (NPV, $MM)	$60,000	$13,000	$73,000
Efficiency Program Spending - Utility (NPV, $MM)	$80,000	$13,000	$93,000
Resulting Savings	**Electric**	**Natural Gas**	**Total**
Net Customer Savings (NPV, $MM)	$277,000	$76,500	$353,500
Annual Customer Savings $MM	*$18,000*	*$5,000*	*$23,000*
Net Societal Savings (NPV, $MM)	$270,000	$74,000	$344,000
Annual Net Societal Savings ($MM)	*$17,500*	*$5,000*	*$22,500*
Decrease in Revenue Requirement (NPV, $MM)	$336,000	$89,000	$425,000
Annual Decrease in Revenue Requirement ($MM)	*$22,000*	*$6,000*	*$28,000*
Energy Savings	**Electric**	**Natural Gas**	**Total**
Percent of Growth Saved, Year 15	61%	52%	
Percent of Consumption Saved, Year 15	12%	5%	
Peak Load Reduction, Year 15 (De-rated)[1]	34,000 MW		
Energy Saved, Year 15	588,000 GWh	1,200 BcF	
Energy Saved (cumulative)	9,400,000 GWh	19,000 BcF	
Emission Reductions	**Electric**	**Natural Gas**	**Total**
CO2 Emission Reduction (1,000 Tons), Year 15	338,000	72,000	410,000
NOx Emission Reduction (Tons), Year 15	67,000	61,000	128,000
Other Assumptions	**Electric**	**Natural Gas**	
Load Growth (%)	2%	1%	
Utility NPV Discount Rate	5%	5%	
Customer NPV Discount Rate	5%	5%	
EE Project Life Term (years)	15	15	

Source: Energy Efficiency Benefits Calculator developed for the National Action Plan for Energy Efficiency, 2006.

NPV = net present value; $MM = million dollars

[1] De-rated peak load reduction based on the coincident peak load reduced multiplied by the percent of growth-related capital expenditures that are saved. Peak load reductions in unconstrained areas are not counted.

As a nation we are passing up these savings by substantially underinvesting in energy efficiency. One indicator of this underinvestment is the level of energy efficiency program funding across the country. Based on the effectiveness of current energy efficiency programs operated in certain parts of the country, the funding necessary to yield the economic and environmental benefits presented above is approximately four times the funding levels for organized efficiency programs today (less than $2 billion per year). Again, this is one indicator of underinvestment and not meant to be a national funding target. Appropriate funding levels need to be established at the regional, state, or utility level based on the cost-effective potential for energy efficiency as well as other factors.

The current underinvestment in energy efficiency is due to a number of well-recognized barriers. Some key barriers arise from choices concerning regulation of electric and natural gas utilities. These barriers include:

- *Market barriers*, such as the well-known "split-incentive" barrier, which limits home builders' and commercial developers' motivation to invest in new building energy efficiency because they do not pay the energy bill, and the transaction cost barrier, which chronically affects individual consumer and small business decision-making.

- *Customer barriers*, such as lack of information on energy saving opportunities, lack of awareness of how energy efficiency programs make investments easier through low-interest loans, rebates, etc., lack of time and attention to implementing efficiency measures, and lack of availability of necessary funding to invest in energy efficiency.

- *Public policy barriers*, which often discourage efficiency investments by electric and natural gas utilities, transmission and distribution companies, power producers and retail electric providers. Historically these organizations have been rewarded more for building infrastructure (e.g., power plants, transmission lines, pipelines) and increasing energy sales than for helping their customers use energy wisely even when the energy-saving measures might cost less.[10]

- *Utility, state, and region planning barriers*, which do not allow energy efficiency to compete with supply-side resources in energy planning.

- *Energy efficiency program barriers*, which limit investment due to lack of knowledge about the most effective and cost-effective energy efficiency program portfolios, programs for overcoming common market barriers to energy efficiency, or available technologies.

While a number of energy efficiency policies and programs contribute to addressing these barriers such as building codes, appliance standards, and state government leadership programs, energy efficiency programs organized through electricity and gas providers also encourage greater energy efficiency in the homes, buildings, and facilities that exist today that will consume the majority of the energy used in these sectors for years to come.

[10] Many energy efficiency programs have an average lifecycle cost of $0 03/kWh saved, which is 50-75% of the typical cost of new power sources (ACEEE, 2004, EIA, 2006)

The National Action Plan for Energy Efficiency

To drive a sustainable, aggressive national commitment to energy efficiency through gas and electric utilities, utility regulators, and partner organizations, more than 50 leading organizations joined together to develop this National Action Plan for Energy Efficiency. The Leadership Group members (Table 1-2) have developed this National Action Plan for Energy Efficiency Report, which:

- Reviews the barriers limiting greater investment in energy efficiency by gas and electric utilities and partner organizations.
- Presents sound business strategies that are available to overcome these barriers.
- Documents a set of business cases showing the impacts on key stakeholders as utilities under different circumstances increase energy efficiency programs.
- Presents best practices for energy efficiency program design and operation.
- Presents policy recommendations and options for spurring greater investment in energy efficiency by utilities and energy consumers.

The report chapters address four main policy and program areas (see Figure 1-3):

- *Utility Ratemaking and Revenue Requirements.* Lost sales from the expanded use of energy efficiency have a negative effect on the financial performance of electric and natural gas utilities, particularly those that are investor-owned under conventional regulation. Cost-recovery strategies have been designed and implemented to successfully "decouple" utility financial health from electricity sales volumes to remove financial disincentives to energy efficiency, and incentives have been developed and implemented to make energy efficiency investments as financially rewarding as capital investments.

The goal of the National Action Plan for Energy Efficiency is to create a sustainable, aggressive national commitment to energy efficiency through gas and electric utilities, utility regulators, and partner organizations.

The Leadership Group:

- Recognizes that utilities and regulators have critical roles in creating and delivering energy efficiency programs to their communities.
- Recognizes that success requires the joint efforts of the customer, utility, regulator, and partner organizations.
- Will work across their spheres of influence to remove barriers to energy efficiency.
- Commits to take action within their own organization to increase attention and investment in energy efficiency.

Leadership Group Recommendations:

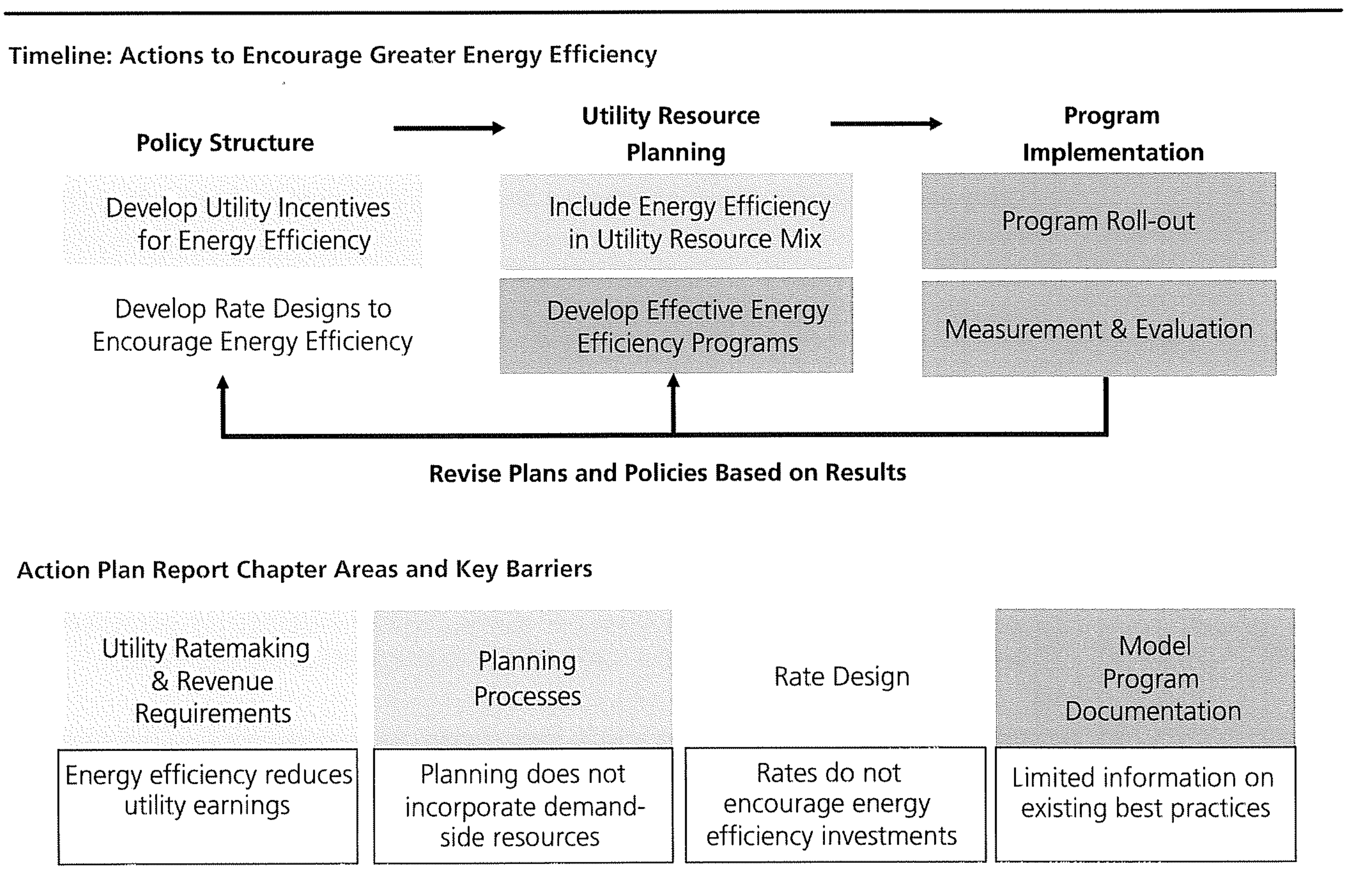
- Recognize energy efficiency as a high-priority energy resource.
- Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource.
- Broadly communicate the benefits of and opportunities for energy efficiency.
- Promote sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective.
- Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments.

- *Planning Processes.* Energy efficiency, along with other customer-side resources, are not fully integrated into state and utility planning processes that identify the need to acquire new electricity and natural gas resources.

- *Rate Design.* Some regions are successfully using rate designs such as time-of-use (TOU) or seasonal rates to more accurately reflect the cost of providing electricity and to encourage customers to consume less energy.

- *Energy Efficiency Program Best Practices Documentation.* One reason given for slow adoption of energy efficiency is a lack of knowledge about the most effective and cost-effective energy efficiency program options. However, many states and electricity and gas providers are successfully operating energy efficiency programs across end-use sectors and customer classes, including residential, commercial, industrial, low-income, and small business. These programs employ a variety of approaches, including providing public information and training, offering financing and financial incentives, allowing energy savings bidding, and offering performance contracting.

Figure 1-3: National Action Plan for Energy Efficiency Report Addresses Actions to Encourage Greater Energy Efficiency

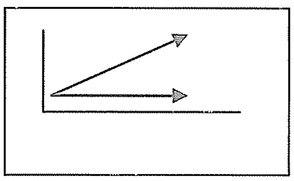


Business Cases for Energy Efficiency

A key element of the National Action Plan for Energy Efficiency is exploring the benefits of energy efficiency and the mechanisms and policies that might need to be modified so that each of the key stakeholders can benefit from energy efficiency investments. A key issue is that adoption of energy efficiency saves resources and utility costs, but also reduces utility sales. Therefore, the effect on utility financial health must be carefully evaluated. To that end, the Leadership Group offers an Energy Efficiency Benefits Calculator (Calculator) that evaluates the financial impact of energy efficiency on its major stakeholders—utilities, customers, and society. The Calculator allows stakeholders to examine different efficiency and utility cases with transparent input assumptions.

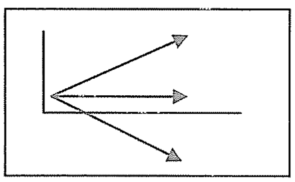
The business cases presented in Chapter 4 of this report show the impact of energy efficiency investments upon sample utility's financial health and earnings, upon customer energy bills, and upon social resources such as net efficiency costs and pollutant emissions. In general, the impacts of offering energy efficiency programs versus not offering efficiency follow the trends and findings illustrated below from the customer, utility and society perspectives.

Utility Perspective. Energy efficiency affects utility revenues, shareholder earnings, and costs associated with capital investments. The utility can be financially neutral to investments in energy efficiency, at a minimum, or encourage greater investment through the implementation of a variety of decoupling, ratemaking, and incentives policies. These policies can ensure that shareholder returns and earnings could be the same or increased. Utility investment in infrastructure and contractual obligations for energy procurement could be reduced, providing a favorable balance sheet impact.



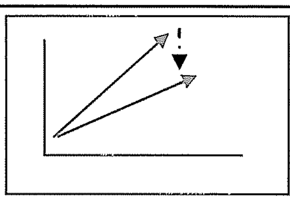
Utility Returns – No Change or Increase

Utility earnings remain stable or increase if decoupling or the use of shareholder incentives accompanies an energy efficiency program. Without incentives, earnings might be lower because effective energy efficiency will reduce the utility's sales volume and reduce the utility's rate base, and thus the scope of its earnings.



Change in Utility Earnings – Results Vary

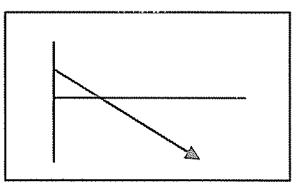
Depending on the inclusion of decoupling and/or shareholder incentives, utility earnings vary. Utility earnings increase if decoupling or shareholder incentives are included. If no incentives, earnings might be lower due to reduced utility investment.



Peak Load Growth and Associated Capital Investment – Decreases

Capital investments in new resources and energy delivery infrastructure are reduced because peak capacity savings are captured due to energy efficiency measures.

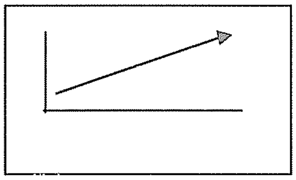
Customer Perspective. Customers' overall bills will decrease with energy efficiency because lower energy usage offsets potential rate increases to cover the cost of offering the efficiency program.



Customer Bills – Decrease

Total customer bills decline over time as a result of investment in cost-effective energy efficiency programs as customers save due to lower energy consumption. This decline follows an initial rise in customer bills reflecting the cost of energy efficiency programs, which will then reduce costs over many years.

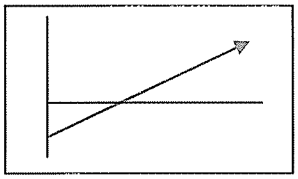
Customer Perspective (continued)



Customer Rates – Mild Increase[12]

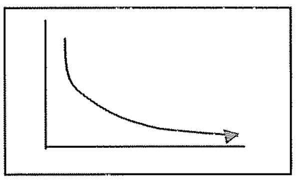
Rates might increase slightly to cover the cost of the energy efficiency program.

Community or Society Perspective. From a broad community/society perspective, energy efficiency produces real savings over time. While initially, energy efficiency can raise energy costs slightly to finance the new energy efficiency investment, the reduced bills (as well as price moderation effects) provide a rapid payback on these investments, especially compared to the ongoing costs to cover the investments in new energy production and delivery infrastructure costs. Moreover, the environmental benefits of energy efficiency continue to grow. The Calculator evaluates the net societal savings, utility savings, emissions reductions, and the avoided growth in energy demand associated with energy efficiency.



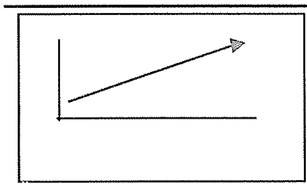
Net Resources Savings – Increases

Over time, as energy efficiency programs ramp up, cumulative energy efficiency savings lead to cost savings that exceed the energy efficiency program cost.



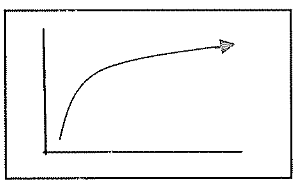
Total Resource Cost (TRC) per Unit - Declines

Total cost of providing each unit of energy (MWh, MMBtu gas) declines over time because of the impacts of energy savings, decreased peak load requirements, and decreased costs during peak periods. Well-designed energy efficiency programs can deliver energy at an average cost less than that of new power sources.



Emissions and Cost Savings – Increases

Efficiency prevents or avoids producing many annual tons of emissions and emission control costs.



Growth Offset by EE – Increases

As energy efficiency programs ramp up, the percent of growth that is offset by energy efficiency climbs and then levels as cumulative savings as a percent of demand growth stabilizes.

12 The changes shown in the business cases indicate a change from what would have otherwise occurred. This change does not include a one-time infrastructure investment in the assumptions, but it does include smooth capital expenditures. Energy efficiency will moderate prices of fossil fuels. The fuel price reductions from an aggressive energy efficiency program upon fuel prices have not been included and could result in an overall rate reduction.

About This Report

The National Action Plan for Energy Efficiency is structured as follows:

Chapter 2: *Utility Ratemaking & Revenue Requirements*

- Reviews mechanisms for removing disincentives for utilities to consider energy efficiency.
- Reviews the pros and cons for different strategies to reward utility energy efficiency performance, including the use of energy efficiency targets, shared savings approaches, and shareholder/company performance incentives.
- Reviews various funding options for energy efficiency programs.
- Presents recommendations and options for modifying policies to align utility incentives with the delivery of cost-effective energy efficiency and providing for sufficient and stable program funding to deliver energy efficiency where cost effective.

Chapter 3: *Energy Resource Planning Processes*

- Reviews state and regional planning approaches, including Portfolio Management and Integrated Resource Planning, which are being used to evaluate a broad array of supply and demand options on a level playing field in terms of their ability to meet projected energy demand.
- Reviews methods to quantify and simplify the value streams that arise from energy efficiency investments—including reliability enhancement/congestion relief, peak demand reductions, and greenhouse gas emissions reductions—for direct comparison to supply-side options.
- Presents recommendations and options for making a strong, long-term commitment to cost-effective energy efficiency as a resource.

Chapter 4: *Business Case for Energy Efficiency*

- Outlines the business case approach used to examine the financial implications of enhanced energy efficiency investment on utilities, consumers, and society.
- Presents case studies for eight different electric and natural gas utility situations, including different ownership structures, gas and electric utilities, and different demand growth rates.

Chapter 5: *Rate Design*

- Reviews a variety of rate design structures and their effect in promoting greater investment in energy efficiency by the end-user.
- Presents recommended strategies that encourage greater use of energy efficiency through rate design.

Chapter 6: *Energy Efficiency Program Best Practices*

- Reviews and presents best practices for operating successful energy efficiency programs at a portfolio level, addressing issues such as assessing energy efficiency potential, screening energy efficiency programs for cost-effectiveness, and developing a portfolio of approaches.
- Provides best practices for successful energy efficiency programs across end-use sectors, customer classes, and a broad set of approaches.
- Documents the political and administrative factors that lead to program success.

Chapter 7: *Report Summary*

- Summarizes the policy and program recommendations and options.

For More Information

Visit the National Action Plan for Energy Efficiency Web site: *www.epa.gov/cleanenergy/eeactionplan.htm* or contact:

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Table 1-2. Members of the National Action Plan for Energy Efficiency

Co-Chairs

Diane Munns	Member President	Iowa Utilities Board National Association of Regulatory Utility Commissioners
Jim Rogers	President and Chief Executive Officer	Duke Energy

Leadership Group

Barry Abramson	Senior Vice President	Servidyne Systems, LLC
Angela S. Beehler	Director of Energy Regulation	Wal-Mart Stores, Inc.
Bruce Braine	Vice President, Strategic Policy Analysis	American Electric Power
Jeff Burks	Director of Environmental Sustainability	PNM Resources
Kateri Callahan	President	Alliance to Save Energy
Glenn Cannon	General Manager	Waverly Light and Power
Jorge Carrasco	Superintendent	Seattle City Light
Lonnie Carter	President and Chief Executive Officer	Santee Cooper
Mark Case	Vice President for Business Performance	Baltimore Gas and Electric
Gary Connett	Manager of Resource Planning and Member Services	Great River Energy
Larry Downes	Chairman and Chief Executive Officer	New Jersey Natural Gas (New Jersey Resources Corporation)
Roger Duncan	Deputy General Manager, Distributed Energy Services	Austin Energy
Angelo Esposito	Senior Vice President, Energy Services and Technology	New York Power Authority
William Flynn	Chairman	New York State Public Service Commission
Jeanne Fox	President	New Jersey Board of Public Utilities
Anne George	Commissioner	Connecticut Department of Public Utility Control
Dian Grueneich	Commissioner	California Public Utilities Commission
Blair Hamilton	Policy Director	Vermont Energy Investment Corporation
Leonard Haynes	Executive Vice President, Supply Technologies, Renewables, and Demand Side Planning	Southern Company
Mary Healey	Consumer Counsel for the State of Connecticut	Connecticut Consumer Counsel
Helen Howes	Vice President, Environment, Health and Safety	Exelon
Chris James	Air Director	Connecticut Department of Environmental Protection
Ruth Kinzey	Director of Corporate Communications	Food Lion
Peter Lendrum	Vice President, Sales and Marketing	Entergy Corporation
Rick Leuthauser	Manager of Energy Efficiency	MidAmerican Energy Company
Mark McGahey	Manager	Tristate Generation and Transmission Association, Inc.
Janine Migden-Ostrander	Consumers' Counsel	Office of the Ohio Consumers' Counsel
Richard Morgan	Commissioner	District of Columbia Public Service Commission
Brock Nicholson	Deputy Director, Division of Air Quality	North Carolina Air Office
Pat Oshie	Commissioner	Washington Utilities and Transportation Commission
Douglas Petitt	Vice President, Government Affairs	Vectren Corporation

Bill Prindle	Deputy Director	American Council for an Energy-Efficient Economy
Phyllis Reha	Commissioner	Minnesota Public Utilities Commission
Roland Risser	Director, Customer Energy Efficiency	Pacific Gas and Electric
Gene Rodrigues	Director, Energy Efficiency	Southern California Edison
Art Rosenfeld	Commissioner	California Energy Commission
Jan Schori	General Manager	Sacramento Municipal Utility District
Larry Shirley	Division Director	North Carolina Energy Office
Michael Shore	Senior Air Policy Analyst	Environmental Defense
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Deb Sundin	Director, Business Product Marketing	Xcel Energy
Dub Taylor	Director	Texas State Energy Conservation Office
Paul von Paumgartten	Director, Energy and Environmental Affairs	Johnson Controls
Brenna Walraven	Executive Director, National Property Management	USAA Realty Company
Devra Wang	Director, California Energy Program	Natural Resources Defense Council
Steve Ward	Public Advocate	State of Maine
Mike Weedall	Vice President, Energy Efficiency	Bonneville Power Administration
Tom Welch	Vice President, External Affairs	PJM Interconnection
Jim West	Manager of *energy right* & Green Power Switch	Tennessee Valley Authority
Henry Yoshimura	Manager, Demand Response	ISO New England Inc.

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Donald Gilligan	President	National Association of Energy Service Companies
Chuck Gray	Executive Director	National Association of Regulatory Utility Commissioners
John Holt	Senior Manager of Generation and Fuel	National Rural Electric Cooperative Association
Joseph Mattingly	Vice President, Secretary and General Counsel	Gas Appliance Manufacturers Association
Kenneth Mentzer	President and Chief Executive Officer	North American Insulation Manufacturers Association
Christina Mudd	Executive Director	National Council on Electricity Policy
Ellen Petrill	Director, Public/Private Partnerships	Electric Power Research Institute
Alan Richardson	President and Chief Executive Officer	American Public Power Association
Steve Rosenstock	Manager, Energy Solutions	Edison Electric Institute
Diane Shea	Executive Director	National Association of State Energy Officials
Rick Tempchin	Director, Retail Distribution Policy	Edison Electric Institute
Mark Wolfe	Executive Director	Energy Programs Consortium

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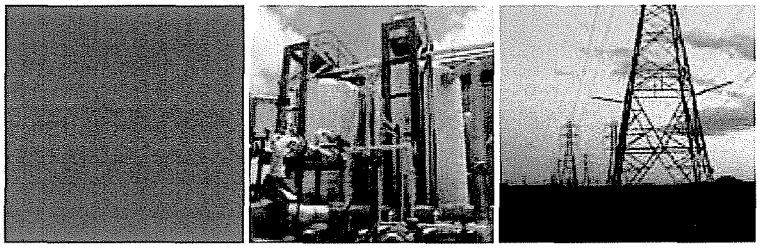
2: Utility Ratemaking & Revenue Requirements



While some utilities manage aggressive energy efficiency programs as a strategy to diversify their portfolio, lower costs, and meet customer demand, many still face important financial disincentives to implementing such programs. Regulators working with utilities and other stakeholders, as well as boards working with publicly owned utilities, can establish or reinforce several policies to help address these disincentives, including overcoming the throughput incentive, ensuring program cost recovery, and defining shareholder performance incentives.

Overview

The practice of utility regulation is, in part, a choice about how utilities make money and manage risk. These regulatory choices can guide utilities toward or away from investing in energy efficiency, demand response, and distributed generation (DG). Traditional ratemaking approaches have strongly linked a utility's financial health to the volume of electricity or gas sold via the ratemaking structure, creating a disincentive to investment in cost-effective demand-side resources that reduce sales. The ratemaking structure and process establishes the rates that generate the revenues that gas and electric utilities, both public and private, can recover based on the just and reasonable costs they incur to operate the system and to procure and deliver energy resources to serve their customers.

Alternate financial incentive structures can be designed to encourage utilities to actively promote implementation of energy efficiency when it is cost effective to do so. Aligning utility and public interest aims by disconnecting profits and fixed cost recovery from sales volumes, ensuring program cost recovery, and rewarding shareholders can "level the playing field" to allow for a fair, economically based comparison between supply- and demand-side resource alternatives and can yield a lower cost, cleaner, and reliable energy system.

This chapter explores the utility regulatory approaches that limit greater deployment of energy efficiency as a resource in U.S. electricity and natural gas systems. Generally, it is within the power of utility commissions and utilities to remove these barriers.[1] Eliminating the throughput incentive is one way to remove a disincentive to invest in efficiency. Offering shareholder incentives will further encourage utility investment. Other disincen-

Leadership Group Recommendations Applicable to Utility Ratemaking and Revenue Requirements

- Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments.
- Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource.
- Broadly communicate the benefits of and opportunities for energy efficiency.
- Provide sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective.

A more detailed list of options specific to the objective of promoting energy efficiency in ratemaking and revenue requirements is provided at the end of this chapter.

[1] In some cases, state law limits the latitude of a commission to grant ratemaking or earnings flexibility. Removing barriers to energy efficiency in these states faces the added challenge of amending statutes

tives for energy efficiency include a short-term resource acquisition horizon and wholesale market rules that do not capture the system value of energy efficiency. After an introduction to these barriers and solutions, this chapter will report on successful efforts in states to implement these solutions. The chapter closes with a set of recommendations for pursuing the removal of these barriers.

This chapter refers to utilities as integrated energy companies selling electricity as well as delivering it. Many of these concepts, however, also apply to states that removed retail electricity sales responsibilities from utilities—turning the utility into an electric transmission and distribution company without a retail sales function.

Barriers and Solutions to Effective Energy Efficiency Deployment

Common disincentives for utilities to invest more in cost-effective energy efficiency programs include the "throughput incentive," the lack of a mechanism for utilities to recover the costs of and provide funding for energy efficiency programs, and a lack of shareholder and other performance incentives to compete with those for investments in new generation.

Traditional Regulation Motivates Utilities to Sell More: The Throughput Incentive

Rates change with each major "rate case," the traditional and dominant form of state-level utility ratemaking.[2] Between rate cases, utilities have a financial incentive to increase retail sales of electricity (relative to forecast or historic levels, which set "base" rates) and to maximize the "throughput" of electricity across their wires. This incentive exists because there is often a significant incremental profit margin on incremental sales. When rates are reset, the throughput incentive resumes with the new base. In jurisdictions where prices are capped for an extended time, the utility might be particularly anxious to grow sales to add revenue to cover cost increases that might occur during the freeze.

With traditional ratemaking, there are few mechanisms to prevent "over-recovery" of costs, which occurs if sales are higher than projected, and no way to prevent "under-recovery," which can happen if forecast sales are too optimistic (such as when weather or regional economic conditions deviate from forecasted or "normal" conditions).[3]

This dynamic creates an automatic disincentive for utilities to promote energy efficiency, because those actions will reduce the utility's net income—even if energy efficiency is clearly established and agreed-upon as a less expensive means to meet customer needs as a least-cost resource and is valuable to the utility for risk management, congestion reduction, and other reasons (EPA, 2006). The effect of this disincentive is exacerbated in the case of distribution-only utilities, because the revenue impact of electricity sales reduction is disproportionately larger for utilities without generation resources. While some states have ordered utilities to implement energy efficiency, others have questioned the practicality of asking a utility to implement cost-effective energy efficiency when their financial self-interest is to have greater sales.

Several options exist to help remove this financial barrier to greater investment in energy efficiency:

Decouple Sales from Profits and Fixed Cost Recovery
Utilities can be regulated or managed in a manner that allows them to receive their revenue requirement with less linkage to sales volume. The point is to regulate utilities such that reductions in sales from consumer-funded energy

[2] Public power utilities and cooperative utilities have their own processes to adjust rates that do not require state involvement

[3] Over-recovery means that more money is collected from consumers in rates than is needed to pay for allowed costs, including return on investment. This happens because average rates tend to collect more for sales in excess of projected demand than the marginal cost to produce and deliver the electricity for those increased sales. Likewise, under-recovery happens if sales are less than the amount used to set rates (Moskovitz, 2000).

Utility and Industry Structure and Energy Efficiency

Publicly and Cooperatively Owned Utilities Compared With Investor-Owned Utilities

The throughput incentive affects municipal and cooperative utilities in a distinctive way. Public power and co-ops and their lenders are concerned with ensuring that income covers debt costs, while they are not concerned about "profits." Available low-cost financing for co-ops sometimes comes with restrictions that limit its use to power lines and generation, further diminishing interest in energy efficiency investments.

Natural Gas vs. Electric Utilities

Natural gas and electric utilities both experience the throughput incentive under traditional ratemaking. Natural gas utilities operate in a more competitive environment than do electric utilities because of the non-regulated alternative fuels, but this situation can cut either way for energy efficiency. For some gas utilities, energy efficiency is an important customer service tool, while in other cases, it is just seen as an imposed cost that competitors do not have. Natural gas companies in the United States also generally see a decline in sales due to state-of-the-art efficiencies in gas end uses, a phenomenon not seen by electric companies. Yet cost-effective efficiency opportunities for local gas distribution companies remain available.

Restructured vs. Traditional Markets

The transition to retail electric competition threw open for reconsideration all assumptions about utility structure. The effects on energy efficiency have been strongly positive and negative. The throughput incentive is stronger for distribution-only companies with no generation and transmission rate base. Price caps, which typically are imposed in a transition to retail competition, diminish utility incentive to reduce sales because added revenue helps cope with new costs. Price caps also discourage utilities from adding near-term costs that can produce a long-term benefit, such as energy efficiency. As a result, energy efficiency is often disconnected from utility planning. On the other hand, several states have provided stable funding for energy efficiency as part of the restructuring process.

High-Cost vs. Low-Cost States

Energy efficiency has been more popular in high-cost states. Low-cost states tend to see energy efficiency as more expensive than their supplies from hydroelectric and coal sources, though there are exceptions where efficiency is seen as a low-cost incremental resource and a way to meet environmental goals. Looking forward, all states face similar, higher cost options for new generation, suggesting that the current resource mix will be less important than future resource options in considering the value of new energy efficiency investments.

efficiency, building codes, appliance standards, and distributed generation are welcomed, and not discouraged.

For example, if utility revenues were connected to the number of customers, instead of sales, the utility would experience different incentives and might behave quite differently. Under this approach, at the conclusion of a conventional revenue requirement proceeding, a utility's revenues per customer could be fixed. An automatic adjustment to the revenue requirement would occur to account for new or departing customers (a more reliable driver of costs than sales). An alternative to the revenue per customer approach is to use a simple escalation formula to forecast the fixed cost revenue requirement over time.

Under this type of rate structure, a utility that is more efficient and reduces its costs over time through energy efficiency will be able to increase profits. Furthermore, if sales are reduced by any means (e.g., efficiency, weather, or economic swings) revenues and profits will not be affected.

This approach eliminates the throughput disincentive and does not require a commission resolution of the amount of lost revenues associated with energy efficiency (see Table 2-1). A critical element of revenue decoupling is a true-up of actual results to forecasted results. Rates would vary up or down reflecting a balancing account for total authorized revenue requirements and actual revenues from electricity or gas consumed by customers. The true-up is fundamental to accomplish decoupling profits and fixed cost revenues from sales volumes. Annual adjustments have been typical and can be modeled in the Energy Efficiency Benefits Calculator (see Chapter 4: Business Case for Energy Efficiency), but a quarterly or monthly adjustment might be preferred. The plan may also include a deadband, meaning that modest deviations from the forecast would produce no change in rates, while larger deviations will result in a rate change. The plan might also share some of the deviations between customers and the utility. The magnitude of rate changes at any one time can be capped if the utility and regulators agree to defer the balance of exceptional changes to be resolved later. Prudence reviews should be unaffected by a decoupling plan. A decoupling plan would typically last a few years and could be changed to reflect new circumstances and lessons learned. Decoupling has the potential to lower the risk of the utility, and this feature should lead to consumer benefits through an overall lower cost of capital to the utility.[4]

Decoupling through a revenue per customer cap is presently more prevalent in natural gas companies, but can be a sound tool for electric companies also. Rate design need not be affected by decoupling (see Chapter 5: Rate Design for rate design initiatives that promote energy efficiency), and a shift of revenues from the variable portion of rates to the fixed portion does not address the throughput incentive. The initial revenue requirement would be determined in a routine rate case, the revenue per customer calculation would flow from the same billing determinants used to set rates. Service performance measures can be added to assure that cost reductions result from efficiency rather than service reductions. Some state laws limit the use of balancing accounts and true-ups, so legislative action would be necessary to enable decoupling in those states.

A decoupling system can be simple or complex, depending on the needs of regulators, the utility, or other parties and the value of a broad stakeholder process leading up to a decoupling system (Kantor, 2006). As the text box addressing lessons learned suggests, it is important to establish the priorities that the system is being created to address so it can be as simple as possible while avoiding unintended consequences. Additionally, it is important to evaluate any decoupling system to ensure it is performing as expected.[5]

Shifting More Utility Fixed Costs Into Fixed Customer Charges

Traditionally, rates recover a portion of the utility's fixed costs through volumetric rates, which helps service remain affordable. To better assure recovery of capital asset costs with reduced dependence on sales, state utility commissions could reduce variable rates and increase the fixed rate component, often referred to as the fixed charge or customer charge. This option might be particularly relevant in retail competition states because wires-only electric utilities have relatively high proportions of fixed costs. This shift is attractive to some natural gas systems experiencing sales volume attrition due to improved furnace efficiency and other trends. This shift reduces the throughput incentive for distribution companies and is an alternative to decoupling. There are some limiting concerns, including the effect a reduction in the variable charge might have on consumption and consumers' motivation to practice energy efficiency, and the potential for high using consumers to benefit from the change while low-using customers pay more.

[4] The lowering of a gas utility's cost of capital because of the reduced risk introduced by a revenue decoupling mechanism was recently affirmed by Barone (2006)

[5] Two recent papers discuss decoupling in some detail: Costello, 2006 and NERA, 2006

The First Wave of Decoupling and Lessons Learned

In the early 1990s, several state commissions and utilities responded to the throughput incentive by creating decoupling systems. In all cases, decoupling was discontinued by the end of the decade. The reasons for discontinuation provide guidance to those considering decoupling today and indicate that the initial idea was good, but that the execution left important issues unaddressed.

In the case of California, decoupling was functioning well, using forecasted revenues and true-ups to actuals, but the move to retail competition precipitated its end in 1996 (CPUC, 1996). Following the energy crisis of 2000-2001, California recognized the importance of long-term energy efficiency investments and reinstated mechanisms to eliminate the throughput incentive.

Puget Sound Energy in Washington adopted a decoupling plan in 1990. There were several problems. The split between variable power costs (recovered via a true-up based on actual experience) and fixed costs (recovered based on a revenue-per-customer calculation) was wrong. While customer numbers (and revenue) were increasing, new investments in transmission were not needed so the fixed cost part of the plan over-recovered. Meanwhile, new generation from independent generators was too expensive, and this added power cost (minus a prudence disallowance, which further complicated the scene) was passed to ratepayers. Unlike the current California decoupling method, there was no reasonable forecast over time for power costs. Risk of power cost increases was insufficiently shared. The results were a big rate increase and anger among customers. In retrospect, risk allocation and the split of fixed and variable costs were incompatible to the events that followed and offer a useful lesson to future attempts. The true-up process and the weather normalization process worked well. The power costs that ignited the controversy over the decoupling plan would have been recoverable in rates under the traditional system. A recent effort to restore decoupling with Puget foundered over a dispute about whether the allowed return on equity during a prior rate case should be changed if decoupling was reinstated (Jim Lazar, personal communication, October 21, 2005).

Central Maine Power also adopted a decoupling plan at the beginning of the 1990s. The plan was ill-equipped, however, to account for an ensuing steep economic downturn that reduced sales by several percentage points. Unfortunately, this effect far outweighed any benefits from energy efficiency. The true-ups called for in the plan were onerous due to the dip in sales, and authorities decided to delay them in hopes that the economy would turn around. When that did not happen, the rate change was quite large and was attributed to the decoupling plan, even though most of the rate increase was due to reduced sales and would have occurred anyway. A lesson from this experience is to not let the period between true-ups go on too long and to consider more carefully what happens if market prices, the economy, the weather, or other significant drivers are well outside expected ranges.

In both the Puget and Central Maine cases, responsibility for large rate increases was misassigned to the decoupling plan, when high power costs from independent power producers (Puget) or general economic conditions (Central Maine) were primarily responsible. That said, serious but correctable flaws in the decoupling plans left consumers exposed to more risk than was necessary.

Provide Utilities the Profit Lost Through Efficiency

Another way to address the throughput incentive is to calculate the profits foregone to successful energy efficiency. Lost Revenue Adjustment Mechanisms (LRAM) allow a utility to directly recoup the "lost" profits and contributions to fixed costs associated with not selling additional units of energy because of the success of energy efficiency programs in reducing electricity consumption. The amount of lost profit can be estimated by multiplying the fixed portion of the utility's prices by the energy savings from energy efficiency programs or the energy generated from DG, based on projected savings or ex post impact evaluation studies. The amount of lost estimated profits is then directly returned to the utility's shareholders. Some states have adopted these mechanisms either through rate cases or add-ons to the fuel adjustment clause calculations.

Experience has shown that LRAM can allow utilities to recover more profits than the energy efficiency program

Table 2-1. Options to Mitigate the Throughput Incentive: Pros and Cons

Policy	Pros	Cons
Traditional cost of service plus return regulation	• Familiar system for regulators and utilities. • Rate changes follow rate cases (except for fuel/purchased gas adjustment clause states).	• Reduced sales reduce net income and contributions to fixed costs. • Sales forecasts can be contentious. • Harder to connect good utility performance to a financial consequence. Risks outside control of utility might be assigned to the utility.
Decoupling (use of a forecast of revenue or revenue per customer, with true-ups to actual results during a defined timeframe)	• Removes sales incentive and distributed resource disincentives. • Authorized fixed costs covered by revenue. • All beneficial actions and policies that reduce sales (distributed generation, energy efficiency programs, codes and standards, voluntary actions by customers, demand response) can be promoted by the utility without adversely affecting net income or coverage of fixed costs. Opportunity to easily reward or penalize utilities based on performance. • True-ups from balancing accounts or revenue per customer are simple. • Easy to add productivity factors, inflation adjustments, and performance indicators with rewards and penalties that can be folded into the true-up process. • Reduces volatility of utility revenue resulting from many causes. Risks from abnormal weather, economic performance, or energy markets can be allocated explicitly between customers and the utility.	• Lack of experience. Viewed by some as a more complex process. • Quality of forecasts is very important. • Some consumer advocates are uncomfortable with rate adjustments outside rate case or familiar fuel adjustment clause. • Frequent rate adjustments from true-ups are objectionable to those favoring rate stability who worry about accountability for rate increases. • Process of risk allocation can cause decoupling plan to break down. Connection between reconstituted risks and cost of capital can cause impasse. • Many issues to factor into the decoupling agreement. Past experience with decoupling indicates that it can be hard to "get it right," though these experiences suggest solutions.
Lost revenue adjustment	• Restores revenue to utility that would have gone to earnings and coverage of fixed costs but is lost by energy efficiency. • Diminishes the throughput disincentive for specific qualifying programs.	• Any sales reductions from efficiency initiatives outside qualifying programs are not addressed, leaving the throughput incentive in place. • Historically contentious, complex process to decide on lost revenue adjustment. Potentially rewards under-performing energy efficiency programs.
Independent energy efficiency administration	• Administration of energy efficiency is assigned to an entity without the conflict of the throughput incentive.	• Utility can still promote load building. Programs that would reduce sales outside the activities of the independent administrator might still be discouraged due to the throughput incentive.

actually saved because the lost profit is based on projected, rather than actual, energy savings. Resolving LRAM in rate cases has been contentious in some states. Furthermore, because utilities still earn increased profits on additional sales, this approach still discourages utilities from implementing additional energy efficiency or supporting independent energy efficiency activities. A comparison of decoupling and the LRAM approach is provided in Table 2-1.

A variation is to roughly estimate the amount of lost profits and make a specified portion (50 to 100 percent) available to the utility to collect based on its performance at achieving certain program goals. This approach is simpler and more constructive than a commission docket to calculate lost revenue. It provides a visible way for the utility to earn back lost profits with program performance and achievements consistent with the public interest. This system translates well into employee merit pay systems, and the goals can fit nicely into management objectives reported to shareholders, a utility's board of directors, or Governors. Public interest groups appreciate the connection to performance.

Non-Utility Administration

Several states, such as Oregon, Vermont and New York, have elected to relieve utilities from the task of managing energy efficiency programs. In some cases, state government has taken on this responsibility, and in others, a third party was created or hired for this purpose. The utility still has the throughput incentive, so while efficiency administration might be without conflict, the utility may still engage in load-building efforts contrary to the messages from the efficiency programs. Addressing the throughput incentive remains desirable even where non-utility administration is in place. Non-utility energy efficiency administration can apply to either electricity or natural gas. Where non-utility energy efficiency administration is in place, cooperation with the utility remains important to ensure that the customer receives good service (Harrington, 2003).

Wholesale Power Markets and the Throughput Incentive

In recent years, wholesale electric power prices have increased, driven by increases in commodity fuel costs. In many parts of the country, these increases have created a situation in which utilities with generation or firm power contracts that cost less than clearing prices might make a profit if they can sell excess energy into the wholesale market. Some have questioned whether or not the situation of utilities seeing wholesale profits from reduced retail sales diminishes or removes the throughput incentive.

Empirically, these conditions do not appear to have moved utilities to accelerate energy efficiency program deployment. In states in which generation is divested from the local utility, the companies serving retail customers see no change to the throughput incentive. There is little to suggest how these market conditions will persist or change. In the absence of a more definitive course change, evidence suggests that the recent trend should not dissuade policymakers and market participants from addressing the throughput incentive.

Recovering Costs / Providing Funding for Energy Efficiency Programs

Removing the throughput incentive is a necessary step in addressing the barriers many utilities face to investing more in energy efficiency. It is unlikely to be sufficient by itself in promoting greater investment, however, because under traditional ratemaking, utilities might be unable to cover the costs of running energy efficiency programs.[6] To ensure funds are available for energy efficiency, policy-makers can utilize and establish the following mechanisms with cooperation from stakeholders:

Revenue Requirement or Procurement Funding

Policy-makers and regulators can set clear expectations that utilities should consider energy efficiency as a resource in their resource planning processes, and it should spend money to procure that resource as it would

[6] See Chapter 3. Energy Resource Planning Processes for discussion of utility resource planning budgets being used to fund energy efficiency

for other resources. This spending would be part of the utility revenue requirement and would likely appear as part of the resource procurement spending for all resources needed to meet consumer demand in all hours. In retail competition states, the default service provider, the distribution company, or a third party can handle the responsibility of acquiring efficiency resources.

Spending Budgets

To reduce regulatory disputes and create an atmosphere of stability among utility managers, trade allies, and customers, the legislature or regulator can determine a budget level for energy efficiency spending—generally a percentage of utility revenue. This budget level would be set to achieve some amount of the potentially available, cost-effective, program opportunities. The spending budget allows administrator staff, trade allies, and consumers to count on a baseline level of effort and reduces the likelihood of spending disruptions that erode customer expectations and destroy hard-to-replace market infrastructure needed to deliver energy efficiency. Unfortunately, spending budgets are sometimes treated as a maximum spending level even if more cost-effective efficiency can be gained. Alternatively, a spending budget can be treated as a minimum if policymakers also declare efficiency to be a resource. In that event, additional cost-effective investments would be recovered as part of the utility revenue requirement.

Savings Target

An alternative to minimum spending levels is a minimum energy savings target. This alternative could be policy-driven (designed for consistency to obtain a certain percentage of existing sales or forecasted growth, or as an Energy Efficiency Portfolio Standard [EEPS]) or resource-driven (changing as system needs dictate). Efficiency budgets can be devised annually to achieve the targets. The use of savings targets does not address how money is collected from customers, or how program administration is organized. For more information on how investments are selected, see Chapter 3: Energy Resource Planning Processes.

Clear, Reliable, and Timely Energy Efficiency Cost Recovery System

Utilities value a clear and timely path to cost recovery, and a well-functioning regulatory process should provide that. Such a process contributes to a stable regulatory atmosphere that supports energy efficiency programs. Cost recovery can be linked to program performance (as discussed in the next section) so that utilities would be responsible for prudent spending of efficiency funds.

The energy efficiency program cost recovery issue is eliminated from the utility perspective if a non-utility administrative structure is used; however, this approach does not eliminate the throughput incentive. Furthermore, funding still needs to be established for the non-utility administrator.

Tariff Rider for Energy Efficiency

A tariff rider for energy efficiency allows for a periodic rate adjustment to account for the difference between planned costs (included in rates) and actual costs.

System Benefits Charge

In implementing retail competition, several states added a separate charge to customer bills to collect funds for energy efficiency programs; several other states have adopted this idea as well. A system benefits charge (SBC) is designed to provide a stable stream of funds for public purposes, like energy efficiency. SBCs do have disadvantages. If the funds enter the purview of state government, they can be vulnerable to decisions to use the funds for general government purposes. Also, the charge appears to be an add-on to bills, which can irritate some consumers. This distinct funding stream can lead to a disconnection in resource planning between energy efficiency and other resources. Regulators and utilities might need to take steps to ensure a comprehensive planning process when dealing with this type of funding.[7]

[7] This device might also pool funds for other public benefit purposes, such as renewable energy system deployment and bill assistance for low-income consumers.

Providing Incentives for Energy Efficiency Investment

Some suggest that if energy efficiency is a cost-effective resource, utilities should invest in it for that reason, with no reason for added incentives. Others say that for effective results, incentives should be considered because utilities are not rewarded financially for energy efficiency resources as they are for supply-side resources. This section reviews options for utility incentives to promote energy efficiency.

When utilities invest in hard assets, they depreciate these costs over the useful lives of the assets. Consumers pay a return on investment for the un-depreciated balance of costs not yet recovered, which spreads the rate effect of the asset over time. Utilities often do not have any opportunity to earn a return on energy efficiency spending, as they do with hard assets. This lack of opportunity for profit can introduce a bias against efficiency investment. Incentives for energy efficiency should be linked to achieving performance objectives to avoid unnecessary expenditures, and be evaluated by regulators based on their ability to produce cost-effective program performance. Performance objectives can also form the basis of penalties for inferior program performance. Financial incentives for utilities should represent revenues above those that would normally be recovered in a revenue requirement from a rate case.

Energy Efficiency Costs: Capitalize or Expense?

In most jurisdictions, energy efficiency costs are expensed, which means all costs incurred for energy efficiency are placed into rates during the year of the expense. When a utility introduces an energy efficiency program, or makes a significant increase or decrease in energy efficiency spending, rates must change to collect all annual costs. An increase in rates might be opposed by consumer advocates and other stakeholders, especially if parties disagree on whether the energy efficiency programs are cost-effective.

To moderate the rate effect of efficiency, regulators could capitalize efficiency costs, at least in part.[8] Capitalizing helps the utility by allowing for cost recovery over time but can cost consumers more than expensing in the long run. Some efficiency programs can meet short term rate-oriented cost-effectiveness tests if costs are capitalized. However, if the choice is made to capitalize, the regulator still has to decide the appropriate amortization period for program costs, balancing concern for immediate rate impacts and long term costs.[9] Capitalizing energy efficiency investments may be limited by the magnitude of "regulatory assets" that is appropriate for a utility. Bond ratings might decline if the utility asset account has too many assets that are not backed by physical capital. The limit on capitalized efficiency investment varies depending on the rest of the utility balance sheet.

Some argue that capitalizing energy efficiency is too costly and that rate effects from expensing are modest. Others note that in some places, capitalizing energy efficiency is the only way to deal with transitional rate effects and can provide a match over time between the costs and benefits of the efficiency investments (Arthur Rosenfeld, personal communication, February 20, 2006).

In some cases, it might be appropriate to consider encouraging unregulated utility affiliates to invest in and benefit from energy efficiency and other distributed resources.

Bonus Return, Shared Savings

To encourage energy efficiency investments over supply investments, regulators can authorize a return on investment that is slightly higher (e.g., 5 percent) for energy efficiency investments or offer a bonus return on equity investment for superior performance. Another approach is to share a percentage of the energy savings value, perhaps 5 to 20 percent, with the utility. A shared savings system has the virtue of linking the magnitude of the

[8] Capitalizing energy efficiency also reinforces the idea of efficiency as a substitute to supply and transmission.

[9] Iowa and Vermont initially capitalized energy efficiency spending, but transitioned to expense in the late 1990s.

reward with the level of program performance. A variation is to hold back some of the funds allocated to energy efficiency for award to shareholders for achieving energy efficiency targets. Where this incentive is used, the holdback can run between 3 and 8 percent of the program budget. Some of these funds can be channeled to employees to reward their efforts (Arthur Rosenfeld, personal communication, February 20, 2006; Plunkett, 2005).

Bonus returns, shared savings, and other incentives can raise the total cost of energy efficiency. However, if the incentives are well-designed and effective, they will encourage the utility to become proficient at achieving energy efficiency savings. The utility might be motivated to provide greater savings for consumers through more cost-effective energy efficiency.

Energy Efficiency Lowers Risk

Energy efficiency can help the financial ratings of utilities if it reduces the risks associated with regulatory uncertainty, long-term investments in gas supply and transport and electric power and transmission, and the risks associated with fossil fuel market prices that are subject to volatility and unpredicted price increases. By controlling usage and demand, utilities can also control the need for new infrastructure and exposure to commodity markets, providing risk management benefits. To the extent that a return on efficiency investments is likely and the chance of a disallowance of associated costs is minimized, investors will be satisfied. Decoupling tends to stabilize actual utility revenues, providing a better match to actual cost, which should further benefit utility bond ratings.

Reversing a Short-Term Resource Acquisition Focus: Focus on Bills, Not Just Rates

Policy-makers tend to focus on electric rates because they can be easily compared across states. They become a measure for business-friendliness, and companies consider rate levels in manufacturing siting and expansion decisions. But rates are not the only measure of service. A short-term focus on low rates can lead to costly missed investment opportunities and higher overall costs of electricity service over the long run.

Over the long term, energy efficiency benefits can extend to all consumers. Eventually, reduced capital commitments and lower energy costs resulting from cost-effective energy efficiency programs benefit all consumers and lower overall costs to the economy, freeing customer income for more productive purposes, like private investment, savings, and consumption. Improved rate stability and risk management from limited sales growth tends to improve the reputation of the utility. Incentives and removing the throughput incentive make it easier for utilities to embrace stable or declining sales.

A commitment to energy efficiency means accepting a new cost in rates over the short-term to gain greater system benefits and lower long-term costs, as is the case with other utility investments. State and local political support with a measure of public education might be needed to maintain stable programs in the face of persistent immediate pressure to lower rates.

Related Issues With Wholesale Markets and Long-Term Planning

Regulatory factors can hinder greater investment in cost-effective energy efficiency programs. These factors include the demand-side of the wholesale market not reacting to supply events like shortages or wholesale price spikes, and, for the electric sector, a short-term generation planning horizon, especially in retail competition states. In addition, transmission system planning by regional transmission organizations (RTOs) and utilities tends to focus on wires and supply solutions, not demand resources like efficiency. The value of sustained usage reductions through energy efficiency, demand response and distributed generation is not generally considered, nor compensated for in wholesale tariffs. These are regulatory choices and are discussed further in Chapter 3: Energy Resource Planning Processes.[10]

[10] Planning and rate design implications are more thoroughly discussed in Chapters 3: Energy Resource Planning Processes and Chapter 5: Rate Design.

Energy Efficiency Makes Wholesale Energy Markets Work Better

In the wholesale market venue, the value of energy efficiency would be revealed by a planning process that treats customer load as a manageable resource like supply and transmission, with investment in demand-side solutions in a way that is equivalent to (not necessarily the same as) supply and transmission solutions. Demand response and efficiency can be called forth that specifically reduces demand at peak times or in other strategic ways, or that reduces demand year-round.

Declare Energy Efficiency a Resource

To underscore the importance of energy efficiency, states can declare in statute or regulatory policy that energy efficiency is a resource and that utilities should factor energy efficiency into resource planning and acquisition. States concerned with risks on the supply side can also go one step further and designate that energy efficiency is the preferred resource.

Link Energy and Environmental Regulation

Environmental policy-makers have observed that energy efficiency is an effective and comparatively inexpensive way to meet tightening environmental limits to electric power generation, yet this attribute rarely factors into decisions by utility regulators about deployment of energy efficiency. This issue is discussed further in Chapter 3: Energy Resource Planning Processes.

State and Regional Examples of Successful Solutions to Energy Efficiency Deployment

Numerous states have previously addressed or are currently exploring energy efficiency electric and gas incentive mechanisms. Experiments in incentive regulation occurred through the mid-1990s but generally were overtaken by events leading to various forms of restructuring. States are expressing renewed interest in incentive regulation due to escalating energy costs and a recognition that barriers to energy efficiency still exist. Many state experiences are highlighted in the following text and Table 2-2.

Addressing the Throughput Disincentive

Direction Through Legislation

New Mexico offers a bold statutory statement directing regulation to remove barriers to energy efficiency: "It serves the public interest to support public utility investments in cost-effective energy efficiency and load management by removing any regulatory disincentives that might exist and allowing recovery of costs for reasonable and prudently incurred expenses of energy efficiency and load management programs" (New Mexico Efficient Use of Energy Act of 2005).

Decoupling Net Income From Sales

California adopted decoupling for its investor-owned companies as it restored utility responsibility for acquiring all cost-effective resources. The state has also required these companies to pursue all cost-effective energy efficiency at or near the highest levels in the United States. A balancing account collects forecasted revenues, and rates are reset periodically to adjust for the difference between actual revenues and forecasts. Because some utility cost changes are factored into most decoupling systems, rate cases can become less frequent, because revenues and costs track more closely over time.[11]

[11] See, for example, orders in California PUC docket A02-12-027. http://www.cpuc.ca.gov/proceedings/A0212027.htm. Oregon had used this method successfully for PacifiCorp, but when the utility was acquired by Scottish Power, the utility elected to return to the more familiar regulatory form.

Maryland and **Oregon** have decoupling mechanisms in place for natural gas. In **Maryland**, Baltimore Gas and Electric has operated with decoupling for more than seven years, and Washington Gas recently adopted decoupling, indicating that regulators view decoupling as a success.[12] In **Oregon**, Northwest Natural Gas has a similar decoupling mechanism in place.[13]

The inherently cooperative nature of decoupling is demonstrated by utilities and public interest advocates agreeing on a system that addresses public and private interests. In all these instances, no rate design shift was needed to implement decoupling—the change is invisible to customers. A new proposal for **New Jersey** Natural Gas would adopt a system similar to those in use in Oregon and Maryland.

See Table 2-2 for additional examples of decoupling.

Reducing Cost Recovery Through Volumetric Charges

After **New York** moved to retail competition and separated energy commodity sales from the electricity delivery utility, the distribution utilities' rates were modified to increase fixed cost recovery through per-customer charges, and to decrease the magnitude of variable, volumetric rates. Removing fixed generation costs, as these

Table 2-2. Examples of Decoupling

State	Type of Utility	Key Features	Related Rate Design Shifts?	Political/Administrative Factors
California	Investor-owned electric and gas	Balancing account to collect forecasted revenue; annual true-up.	No	Driven by commission, outcome of energy crisis; consensus oriented.
	http://www.epa.gov/cleanrgy/pdf/keystone/PrusnekPresentation.pdf http://www.cpuc.ca.gov/Published/Final_decision/15019.htm			
Maryland	Investor-owned gas only	Revenue per customer cap; monthly true-up.	No	Revenue stability primary motive of utility; frequent true-ups.
	http://www.energetics.com/madri/pdfs/timmerman_101105.pdf http://www.bge.com/vcmfiles/BGE/Files/Rates%20and%20Tariffs/Gas%20Service%20Tariff/Brdr_3.doc			
Oregon	Investor-owned gas only at present; investor-owned electric in the past	Revenue per customers cap; annual true-up.	No	Revenue stability primary motive of utility; renewed in 2005.
	http://www.raponline.org/Pubs/General/OregonPaper.pdf http://www.advisorinsight.com/pub/indexes/600_mi/nwn_ir.htm http://www.nwnatural.com/CMS300/uploadedFiles/24190ai.pdf http://apps.puc.state.or.us/orders/2002ords/02-633.pdf			
New Jersey	Investor-owned gas (proposed)	Revenue per customer.	No	Explicit intent of utility to promote energy efficiency and stabilize fixed cost recovery.
	http://www2.njresources.com/news/trans/newsrpt.asp?Year=2005 (see 12/05/05)			
Vermont	Investor-owned electric (proposed)	Forecast revenue cap and costs; balancing account and true-ups.	No	Legislative change promoted utility proposal; small utility looking for stability.
	http://www.greenmountainpower.biz/atyourservice/2006ratefiling.shtml			

[12] BG&E's "Monthly Rate Adjustment" tariff rider is downloadable at http://www.bge.com/portal/site/bge/menuitem.6b0b25553d65180159c031e0da6176a0/

[13] The full agreement can be found in Appendix A of Order 02-634, available at http://apps.puc.state.or.us/orders/2002ords/02-634.pdf. See also Hansen and Braithwait (2005) for an independent assessment of the Northwest Natural Gas decoupling plan prepared for the commission.

assets were divested, dampened the effects on consumers. In combination with tracking and deferral mechanisms to protect the utility from unanticipated costs and savings, the utilities have little incentive to increase electric sales.

Using a Lost Revenue Adjustment

Minnesota provided Xcel Energy with lost revenue adjustments for energy efficiency through 1999, and then moved to a performance-based incentive. **Iowa** currently provides utilities with lost revenue adjustments for energy efficiency. **Connecticut** allows lost revenue recovery for all electric energy efficiency. **Massachusetts** allows lost revenue recovery for all gas energy efficiency, requiring the accumulated lost revenues to be recovered within three years to prevent large accumulated balances. **Oregon** allows lost revenue recovery for utility efficiency programs. Lost revenue adjustments have been removed in many states because of their cost to consumers. **New Jersey** is in the midst of a transition to a state-run administrator and provides lost revenue for utility-run programs in the meantime.

Non-Utility Administration

Several states have taken over the administration of energy efficiency, including **Wisconsin** (Focus on Energy), **Maine** (Efficiency Maine), **New Jersey**, and **Ohio**. In other states, a third party has been set up to administer programs, including **Vermont** (Efficiency Vermont) and **Oregon** (Energy Trust of Oregon). The **New York** State Energy Research and Development Authority (NYSERDA), a public authority, fits into both categories. There is no retail competition in Vermont or Wisconsin; this change was based entirely on an expectation of effectiveness. **Oregon** combines natural gas and electric efficiency programs, but only for the larger companies in each sector. Statewide branding of energy efficiency programs is a dividend of non-utility administration. **Connecticut** introduced an aspect of non-utility administration by vesting its Energy Conservation Management Board, a state board including state officials, utility managers, and others, with responsibility to approve energy efficiency plans and budgets.

Recovering Costs / Providing Funding for Energy Efficiency Programs

Revenue Requirement

When energy efficiency programs first began, they were funded as part of a utility revenue requirement. In many states, like Iowa, this practice has continued uninterrupted. In California, retail competition interrupted this method of acquiring energy efficiency, but since 2003, California is again funding energy efficiency along with other resources through the revenue requirement, a practice known there as "procurement funding." California also funds energy efficiency through SBC funding.

Capitalizing Energy Efficiency Costs

Oregon allows capitalization of costs, and the small electrics do so. Washington, Vermont, and Iowa capitalized energy efficiency costs when programs began in the 1980s to moderate rate effects. **Vermont**, for example, amortized program costs over five years. In the late 1990s, however, as program spending declined, these states ended the practice of capitalizing energy efficiency costs, electing to expense all costs. Currently, **Vermont** stakeholders are discussing how to further increase efficiency spending beyond the amount collected by the SBC, and they are reconsidering moderating new rate effects through capitalizing costs.

Spending Budgets, Tariff Riders, and System Benefits Charges

Several states have specified percentages of net utility revenue or a specific charge per energy unit to be spent for energy efficiency resources. **Massachusetts**, for example, specifies 2.5 mills per kilowatt-hour (kWh) (while spending for natural gas energy efficiency is determined case by case). In **Minnesota**, there is a separate percentage designated for electric (1.5 percent of gross operating revenues) and for natural gas (0.5 percent) utilities. **Vermont** adopted a statewide SBC for its vertically integrated electric sector, while its gas energy efficiency costs remain embedded in the utility revenue requirement. Strong statutory protections guard funds from government appropriation. Wisconsin requires a charge, but leaves the commission to determine the appropriate level for each utility. There is a history of SBC funds being used for general government within the state; 2005 legislation apparently intended to make funding more secure (Wisconsin Act 141 of 2005).

The **New York** commission chose to establish an annual spending budget for its statewide effort (exclusive of the public authorities and utilities), increasing it to $150 million in 2001 and to $175 million in 2006. **Washington** tariffs include a rider that allows adjustment of rates to recover energy efficiency costs that diverge from amounts included in rates, with annual true-ups.

Providing Incentives for Energy Efficiency Investment

Performance Incentives

In **Connecticut**, the two electric utilities managing energy efficiency programs are eligible for "performance management fees" tied to performance goals approved by the regulators, including lifetime energy savings, demand savings, and other measures. Incentives are available for a range of outcomes from 70 to 130 percent of pre-determined goals. In 2004, the two utilities collectively reached 130 percent of their energy savings goals and 124 percent of their demand savings goals. They received performance management fees totaling $5.27 million. The 2006 joint budget anticipates $2.9 million in performance incentives.

In 1999, the **Minnesota** Commission adopted performance incentives for the electric and natural gas investor-owned utilities that began at 90 percent of performance targets and are awarded for up to 150 percent of target levels. Performance targets for Minnesota utilities spending more than the minimum spending requirement are adjusted to the minimum spending level for purposes of calculating the performance incentive.

Rhode Island and **Massachusetts** offer similarly structured incentives. **Rhode Island** sets aside roughly 5 percent of the efficiency budget for performance incentives. This amount is less than the amount that would probably be justified if a lost revenue adjustment were used. A collaborative group of stakeholders recommends performance indicators and levels to qualify for incentives. In **Massachusetts**, utilities achieving performance targets earn 5 percent on money spent for efficiency (in addition to being able to expense efficiency costs).

Efficiency Vermont operates under a contract with the **Vermont** Public Service Board. The original contract called for roughly 3 percent of the budget for efficiency programs to be held back and paid if Efficiency Vermont meets a variety of performance objectives.

Shared Savings

Before retail competition, **California** used a shared savings approach, in which the utilities received revenue equal to a portion of the savings value produced by the energy efficiency programs. A similar mechanism might be reinstated in 2006 (Arthur Rosenfeld, personal communication, February 20, 2006).

Bonus Rate of Return

Nevada allows a bonus rate of return for demand-side management that is 5 percent higher than authorized rates of return for supply investments. Regulations specify programs that qualify and the process to account for qualifying investments (Nevada Regulation of Public Utilities Generally, 2004).

Lower Risk of Disallowance Through Multi-Stakeholder Collaborative

California, **Rhode Island**, and other states employ stakeholder collaboratives to resolve important program and administrative issues and to provide settlements to the regulator.

See Table 2-3 for additional examples of incentives for energy efficiency investments.

Table 2-3. Examples of Incentives for Energy Efficiency Investments

State	Type of Utility	Key Features	Political/Administrative Factors
California	Investor-owned electric	Shared savings	Encouraged by energy commission and utilities. Incentive proportionate to value of savings; no cap.
	http://www.raponline.org/Conferences/Minnesota/Presentations/PrusnekCAEEMinnesota.pdf		
Connecticut	Investor-owned electric	Performance incentives	Part of retail competition bargain; incentive limited to a percentage of program budget; simple to compare results to performance goals.
	http://www.state.ct.us/dpuc/ecmb/index.html		
Massachusetts, Rhode Island	Investor-owned electric	Performance incentives	Part of retail competition bargain; incentive limited to a percentage of program budget; simple to compare results to performance goals.
	http://www.mass.gov/dte/electric/04-11/819order.pdf (Docket 04-11) http://www.ripuc.org/eventsactions/docket/3463_NEC-2004DSMSettle(9.12.03).pdf		
Minnesota	Investor-owned electric and natural gas	Performance incentives	Utility-specific plan arising to resolve other regulatory issues; incentive awarded on a sliding scale of performance compared with goals; decoupling not authorized by statute.
	http://www.raponline.org/Pubs/RatePayerFundedEE/RatePayerFundedMN.pdf		
Nevada	Investor-owned electric	Bonus rate of return on equity	Process to establish bonus is statutory.
	See http://www.leg.state.nv.us/NAC/NAC-704.html#NAC704Sec9523		
Vermont	Efficiency utility	Performance incentives	Incentive structure set by contract; result of bargain between commission and third-party efficiency provider.
	http://www.state.vt.us/psb/eeucontract.html		

Regulatory Drivers for Efficiency in Resource Planning and Energy Markets

Declare Energy Efficiency a Resource

In **New Mexico**, the legislature has declared a goal of "decreasing electricity demand by increasing energy efficiency and demand response, and meeting new generation needs first with renewable and distributed generation resources, and second with clean fossil-fueled generation." (New Mexico Efficient Use of Energy Act of 2005)

In **California**, the state has made it very clear that energy efficiency is the most important resource (California SB 1037, 2005). After the crises of 2000 and 2001, state leaders used energy efficiency to dampen demand growth and market volatility. An Energy Action Plan, adopted in 2003 by the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), and the power authority, developed a "loading order" for new electric resources; the Energy Action Plan has been revised but the energy efficiency preference remains firm. The intent of the loading order is to "decreas(e) electricity demand by increasing energy efficiency and demand response, and meeting new generation needs first with renewable and distributed generation resources, and second with clean fossil-fueled generation" (CEC, 2005). As a result, utilities are acquiring energy efficiency in amounts well in excess of those that would be procured with the SBC alone. Further, the utilities are integrating efficiency into their resource plans and using efficiency to solve resource problems.

Clarifying the primary regulatory status of efficiency makes it clear that sympathetic regulation and cost recovery policies are important. **California** has adopted decoupling of net income and sales for its investor-owned utilities to remove regulatory barriers to a full financial commitment to energy efficiency.

One device for implementing this policy is an energy efficiency supply curve. The CEC created such a curve based on an assessment of energy efficiency potential to provide guidance as it reintroduced energy efficiency procurement expectations for the utilities in 2003. Furthermore, the CPUC cooperated with the CEC to set energy savings targets for each of the California investor-owned utilities based on an assessment of cost-effectiveness potential.

A different approach to declaring energy efficiency a resource is to establish a portfolio or performance standard for energy efficiency. In 2005, **Pennsylvania** and **Connecticut** included energy efficiency in their resource portfolio standards. Requiring all retail sellers to acquire sufficient certificates of energy savings will allocate revenue to efficiency providers in an economically efficient way (Pennsylvania Alternative Energy Portfolio Standards Act of 2004; Connecticut Act Concerning Energy Independence of 2005).

As an outcome of its electric restructuring law, **Texas** is using energy efficiency as a resource to reduce demand. Texas' spending for energy efficiency is intended to produce savings to meet 10% of forecasted electric demand growth. Performance is exceeding this level.

Consider Energy Efficiency As a System Reliability Solution

In New England, Independent System Operator New England (ISO-NE) faced a reliability problem in southwest **Connecticut**. A transmission line to solve the problem was under development, but would not be ready in time. New central station generation could not be sited in this congested area. Because the marketplace was not providing a solution, ISO-NE issued a Request for Proposal (RFP) for any resources that would address the reliability problem and be committed for four years. One energy efficiency bid was selected—a commercial office building lighting project worth roughly 5 megawatts (MW). Conditions of the award were very strict about availability of the capacity savings. This project will help to demonstrate how energy efficiency does deliver capacity. While ISO-NE deemed the RFP an emergency step that it would not undertake routinely, this process demonstrates that energy efficiency can be important to meeting reliability goals and can be paid for through federal jurisdictional tariffs.

Other states, including **Indiana**, **Vermont**, and **Minnesota** direct that energy efficiency be considered as an alternative when utilities are proposing a power line project (Indiana Resource Assessment, 1995; Vermont Section 248; Minnesota Certificate of need for large energy facility, 2005.)

Key Findings

This chapter reviews opportunities to make energy efficiency an attractive business prospect by modifying electric and gas utility regulation, and by the way that utilities collect revenue and make a profit. Key findings of this chapter indicate:

- There are real financial disincentives that hinder all utilities in their pursuit of energy efficiency as a resource, even when it is cost-effective and would lead to a lower cost energy system. Regulation, which is a key source of these disincentives, can be modified to remove these barriers.

- Many states have experience in addressing financial disincentives in the following areas:

  — Overcoming the throughput incentive.

  — Providing reliable means for utilities to recover energy efficiency costs.

  — Providing a return on investment for efficiency programs that is competitive with the return utilities earn on new generation.

  — Addressing the risk of program costs being disallowed and other risks.

  — Recognizing the full value of energy efficiency to the utility system.

Recommendations and Options

The National Action Plan for Energy Efficiency Leadership Group offers the following recommendations as ways to overcome many of the barriers to energy efficiency in utility ratemaking and revenue requirements, and provides a number of options for consideration by utilities, regulators, and stakeholders *(as presented in the Executive Summary)*:

Recommendation: Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments. Successful energy efficiency programs would be promoted by aligning utility incentives in a manner that encourages the delivery of energy efficiency as part of a balanced portfolio of supply, demand, and transmission investments. Historically, regulatory policies governing utilities have more commonly compensated utilities for building infrastructure (e.g., power plants, transmission lines, pipelines) and selling energy, while discouraging energy efficiency, even when the energy-saving measures might cost less. Within the existing regulatory processes, utilities, regulators, and stakeholders have a number of opportunities to create the incentives for energy efficiency investments by utilities and customers. A variety of mechanisms have already been used. For example, parties can decide to provide incentives for energy efficiency similar to utility incentives for new infrastructure investments, and provide rewards for prudent management of energy efficiency programs.

Options to Consider:

- Addressing the typical utility throughput incentive and removing other regulatory and management disincentives to energy efficiency.

- Providing utility incentives for the successful management of energy efficiency programs.

Recommendation: Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource. Energy efficiency programs are most successful and provide the greatest benefits to stakeholders when appropriate policies are established and maintained over the long-term. Confidence in long-term stability of the program will help maintain energy efficiency as a dependable resource compared to supply-side resources, deferring or even avoiding the need for other infrastructure investments, and maintain customer awareness and support.

Options to Consider:

- Establishing funding requirements for delivering long-term, cost-effective energy efficiency.

- Designating which organization(s) is responsible for administering the energy efficiency programs.

Recommendation: Broadly communicate the benefits of and opportunities for energy efficiency. Experience shows that energy efficiency programs help customers save money and contribute to lower cost energy systems. But these benefits are not fully documented nor recognized by customers, utilities, regulators, or policymakers. More effort is needed to establish the business case for energy efficiency for all decision-makers and to show how a well-designed approach to energy efficiency can benefit customers, utilities, and society by (1) reducing customers' bills over time, (2) fostering financially healthy utilities (e.g., return on equity, earnings per share, and debt coverage ratios unaffected), and (3) contributing to positive societal net benefits overall. Effort is also necessary to educate key stakeholders that although energy efficiency can be an important low-cost resource to integrate into the energy mix, it does require funding, just as a new power plant requires funding.

Options to Consider:

- Establishing and educating stakeholders on the business case for energy efficiency at the state, utility, other appropriate level addressing customer, utility, and societal perspectives.

- Communicating the role of energy efficiency in lowering customer energy bills, and system costs and risks over time.

Recommendation: Provide sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective. Energy efficiency programs require consistent and long-term funding to effectively compete with energy supply options. Efforts are necessary to establish this consistent long-term funding. A variety of mechanisms have been, and can be used, based on state, utility, and other stakeholder interests. It is important to ensure that the efficiency program providers have sufficient long-term funding to recover program costs, and implement the energy efficiency measures that have been demonstrated to be available and cost-effective. A number of states are now linking program funding to the achievement of energy savings.

Options to Consider:

- Deciding on, and committing to, a consistent way for program administrators to recover energy efficiency costs in a timely manner.
- Establishing funding mechanisms for energy efficiency from among the available options, such as revenue requirement or resource procurement funding, SBCs, rate-basing, shared-savings, incentive mechanisms, etc.
- Establishing funding for multi-year periods.

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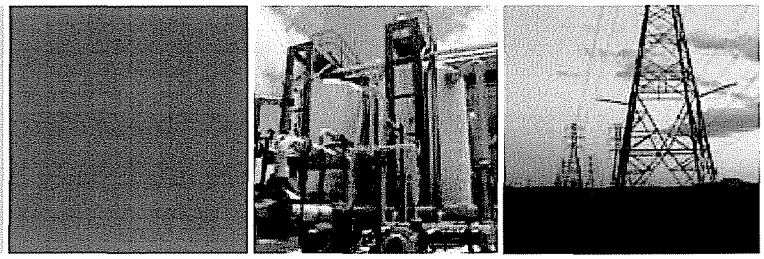
3: Energy Resource Planning Processes



Including energy efficiency in the resource planning process is essential to realizing its full value and setting resource savings and funding targets accordingly. Many utilities, states, and regions are estimating and verifying the wide range of benefits from energy efficiency and are successfully integrating energy efficiency into the resource planning process. This chapter of the National Action Plan for Energy Efficiency Report discusses the barriers that obstruct incorporating energy efficiency in resource planning and presents six regional approaches to demonstrate how those barriers have been successfully overcome.

Overview

Planning is a core function of all utilities: large and small, natural gas and electric, public and private. The decisions made in planning affect customer costs, reliability of service, risk management, and the environment. Many stakeholders are closely involved and participate in planning processes and related decisions. Active participants often include utilities, utility regulators, city councils, state and local policy-makers, regional organizations, environmental groups, and customer groups. Regional planning processes organized through regional transmission organizations (RTOs) also occur with the collaborations of utilities and regional stakeholders.

Different planning processes are employed within each utility, state, and region. Depending on a utility's purpose and context (e.g., electric or gas utility, vertically integrated or restructured), different planning decisions must be made. Local and regional needs also affect planning and resource requirements and the scope of planning processes. Further, the role of states and regions in planning affects decisions and prescribes goals for energy portfolios, such as resource priority, fuel diversity, and emissions reduction.

Through different types of planning processes, utilities analyze how to meet customer demands for energy and capacity using supply-side resource procurement (including natural gas supply contracts and building new generation), transmission, distribution, and demand-side resources (including energy efficiency and demand response). Such planning often requires iteration and testing to find the combination of resources that offer maximum value over a range of likely future scenarios, for the short- and long-term. The value of each of these resources is determined at the utility, local, state and regional level, based on area-specific needs and policy direction. In order to fully integrate the value of all resources into planning—including energy efficiency—resource value and benefits must be determined early in the planning process and projected over the life of the resource plan.

Planning processes focus on two general areas: (1) energy-related planning, such as electricity generation and wholesale energy procurement; and (2) capacity-related planning, such as construction of new pipelines, power plants, or electric transmission and distribution projects. The value of energy efficiency can be integrated into resource planning decisions for both of these areas.

Leadership Group Recommendations Applicable to Energy Resource Planning Processes

- Recognize energy efficiency as a high-priority energy resource.
- Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource.
- Broadly communicate the benefits of, and opportunities for, energy efficiency.
- Provide sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective.

A more detailed list of options specific to the objective of promoting energy efficiency in resource planning processes is provided at the end of this chapter.

This chapter identifies common challenges for integrating energy efficiency into existing planning processes and describes examples of successful energy efficiency planning approaches that are used in six regions of the country. Finally, this chapter summarizes ways to address barriers, and offers recommendations and several options to consider for specific actions that would facilitate incorporation of energy efficiency into resource planning.

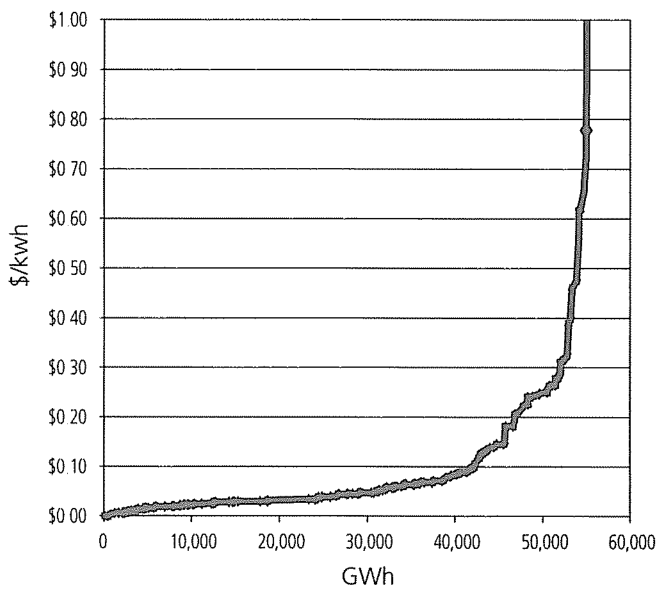
Challenges to Incorporating Energy Efficiency Into Planning

The challenges to incorporating energy efficiency into resource planning have common themes for a wide range of utilities and markets. This section describes these challenges in the context of two central questions: A) determining the value of energy efficiency in the resource planning, and B) setting energy efficiency targets and allocating budgets, which are guided by resource planning, as well as regulatory and policy decisions.

Determining the Value of Energy Efficiency

It is generally accepted that well-designed efficiency measures provide measurable resource savings to utilities. However, there are no standard approaches on how to appropriately quantify and incorporate those benefits into utility resource planning. Also, there are many different types of energy efficiency programs with different characteristics and target customers. Energy efficiency can include utility programs (rebates, audits, education, and outreach) as well as building efficiency codes and standards improvements for new construction. Each type of program has different characteristics that should be considered in the valuation process. The program information gathered in an energy efficiency potential study can be used to create an energy efficiency supply curve, as illustrated in Figure 3-1.

Figure 3-1. Energy Efficiency Supply Curve - Potential in 2011 (Levelized Cost in $/kilowatt-hours [kWh] Saved)



Source: McAuliffe, 2003

Common Challenges to Incorporating Energy Efficiency Into Planning
A. Determining the Value of Energy Efficiency
Energy Procurement
Estimating energy savings
Valuing energy savings
Capacity & Resource Adequacy
Estimating capacity savings
Valuing capacity benefits
Factors in achieving benefits
Other Benefits
Incorporating non-energy benefits
B. Setting Targets and Allocating Budget
Quantity of EE to implement
Estimating program effectiveness
Institutional difficulty in reallocating budget
Cost expenditure timing vs. benefits
Ensuring program costs are recaptured

The analysis commonly used to value energy efficiency compares the costs of energy efficiency resources to the costs of the resources that are displaced by energy efficiency. The sidebar shows the categories of benefits for electric and gas utilities that are commonly evaluated. The approach is to forecast expected future costs with and without energy efficiency resources and then estimate the level of savings that energy efficiency will provide. This analysis can be conducted with varying levels of sophistication depending on the metrics used to compare alternative resource plans. Typically, the evaluation is made based on the expected cost difference; however, "portfolio" approaches also evaluate differences in cost variance and reliability, which can provide additional rationale for including energy efficiency as a resource.

The resource benefits of energy efficiency fall into two general categories:

(1) Energy-related benefits that affect the procurement of wholesale electric energy and natural gas, and delivery losses.

(2) Capacity-related benefits that affect wholesale electric capacity purchases, construction of new facilities, and system reliability.

The energy-related benefits of energy efficiency are relatively easy to forecast. Because utilities are constantly adjusting the amount of energy purchased, short-term deviations in the amount of energy efficiency achieved can be accommodated. The capacity-related benefits occur when construction of a facility needed to reliably serve customers can be delayed or avoided because the need has already been met. Therefore, achieving capacity benefits requires much more certainty in the future success of energy efficiency programs (particularly the measures targeting peak loads) and might be harder to achieve in practice. However, the ability to provide capacity benefits has been a focus in California, the Pacific Northwest, and other regions, and it should become easier to assess capacity savings as more programs gain experience, and capacity savings are measured and verified. Current methods for estimating energy benefits and capacity benefits are presented here.

Estimating Energy Benefits

Estimating energy benefits requires established methods for estimating the quantity of energy savings and the benefits of these savings to the energy system.

- *Estimating Quantity of Energy Savings.* Savings estimates for a wide variety of efficiency measures have been well studied and documented. Approaches to estimate the level of free-riders and program participants who would have implemented the energy efficiency on their own have been established. Similarly, the expected useful lives of energy efficiency measures and their persistence are commonly evaluated and included in the analysis. Detailed databases of efficiency measures have been developed for several regions, including California and the Pacific Northwest. However, it is often necessary to investigate and validate the methods and assumptions behind those estimates to build consensus around measured savings that all stakeholders find credible. Savings estimates can be verified through measurements and load research. Best practices for measurement and verification (M&V) are discussed in more detail in Chapter 6: Energy Efficiency Program Best Practices.

Benefits of Energy Efficiency in Resource Planning

	Electricity	Natural Gas
Energy-related benefits	Reduced wholesale energy purchases	Reduced wholesale natural gas purchases
	Reduced line losses	Reduced losses and unaccounted for gas
	Reduced air emissions	Reduced air emissions
Capacity-related benefits	Generation capacity/ resource adequacy/ regional markets	Production and liquified natural gas facilities
	Operating reserves and other ancillary services	Pipeline capacity
	Transmission and distribution capacity	Local storage and pressure
Other benefits	Market price reductions (consumer surplus)	
	Lower portfolio risk	
	Local/in-state jobs	
	Low-income assistance and others	

- *Quantifying Value of Energy Savings.* The most readily available benchmark for the value of energy savings is the prevailing price of wholesale electricity and natural gas. Even for a vertically integrated utility with its own production, energy efficiency might decrease the need to make market purchases; or if the utility has excess energy, energy efficiency can allow the utility to sell more into the market. In cases when the market prices are not appropriate benchmarks (because of contract limitations on reselling energy or limited market access), contract prices or production costs can be used. In addition, the value of losses and other variable costs associated with energy delivery can be quantified and are well known.

The challenge that remains is in forecasting future energy costs beyond the period when market data are available or contracts are in place. Long-run forecasts vary in complexity from a simple escalation rate to market-based approaches that forecast the cost of new resource additions, to models that simulate the system of existing resources (including transmission constraints) and evaluate the marginal cost of operating the system as new generation is added to meet the forecasted load growth. Most utilities have an established approach to forecast long-term market prices, and the same forecasting technique and assumptions should be used for energy efficiency as are used to evaluate supply-side resource options. In addition to a forecast of energy prices, some regions include the change in market prices as a result of energy efficiency. Estimating these effects requires modeling of complex interactions in the energy market. Furthermore, reduced market prices are not necessarily a gain from a societal perspective, because the gains of consumers result in an equal loss to producers; therefore, whether to include these savings is a policy decision.

Estimating Capacity Benefits

Estimating capacity benefits requires estimating the level of capacity savings and the associated benefits. If energy efficiency's capacity benefits are not considered in the resource plan, the utility will overinvest in capital assets, such as power plants and transmission and distribution, and underinvest in energy efficiency.

- *Estimating Capacity Savings.* In addition to energy savings, electric efficiency reduces peak demand and the need for new investments in generation, transmission, and distribution infrastructure. Natural gas efficiency can reduce the need for a new pipeline, storage, liquefied natural gas (LNG) facility, or other investments necessary to maintain pressure during high-load periods. Because of the storage and pressure variation possible in the natural gas system, capacity-related costs are not as extreme in the natural gas system as they are for electricity. In both cases, estimating reductions of peak demand is more difficult for electricity than it is for natural gas, and timing is far more critical. For peak demand savings to actually be realized, the targeted end-use load reductions must occur, and the efficiency measure must provide savings coincident with the utility's peak demand. Therefore, different energy efficiency measures that reduce load at different times of day (e.g., commercial vs. residential lighting) might have different capacity values. Area- and time-specific marginal costing approaches have been developed to look at the value of coincident peak load reductions, which have significantly higher value during critical hours and in constrained areas of the system (see sidebar on page 3-5).

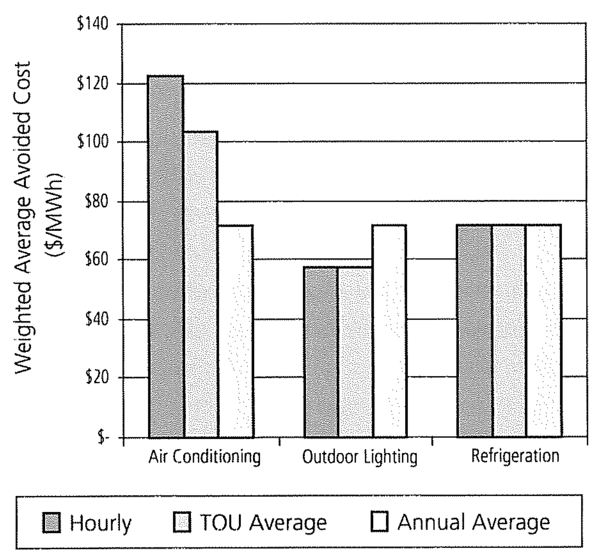
A critical component of the resource planning process, whether focused on demand- or supply-side resources, is accurate, unbiased load forecasting. Inaccurate load forecasts either cause excessive and expensive investment in resources if too aggressive, or create costly shortages if too low. Similarly, tracking and validation of energy efficiency programs are important for increasing the accuracy of estimates of their effects in future resource plans.

Estimating the capacity savings to apply to load growth forecasts requires estimating two key factors. The first is determining the amount of capacity reduced by energy efficiency during critical or peak hours. The second factor is estimating the "equivalent reliability" of the load reduction. This measure captures both the probability that the savings will actually occur, and that the savings will occur during system-constrained hours. Applying estimates of equivalent reliability to various types of resources allows comparison on an equal basis with traditional capacity investments. This approach is similar in concept to the equivalent capacity factor used to compare renewable resources such as wind and solar with traditional fossil-fueled generation. In markets where capacity is purchased, "counting" rules for different resource types determine the equivalent reliability. The probability that savings will actually occur during peak periods is easier to estimate with some certainty for a large number of distributed efficiency measures (e.g., air conditioners) as opposed to a limited number of large, centralized measures (e.g., water treatment plants).

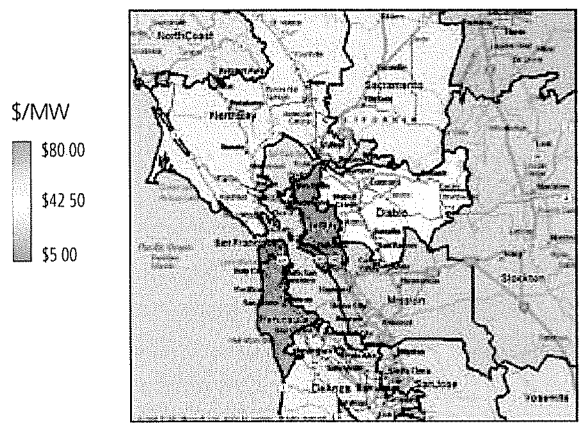
California Avoided Costs by Time and Location

California is a good example of the effect of area and time-differentiation for efficiency measures that have dramatically different impact profiles. The average avoided cost for efficiency (including energy and capacity cost components) in California is $71/megawatt-hour (MWh). Applying avoided costs for each of six time of use (TOU) periods (super-peak, mid-peak and off-peak for summer and winter seasons) increases the value of air conditioning to $104/MWh or 45 percent and lowers the value of outdoor lighting to $57/MWh or 20 percent. Refrigeration, with its consistent load profile throughout the day and year, is unaffected. Applying avoided costs by hour captures the extreme summer peak prices and increases the value of air conditioning savings still further to $123/MWh. Incorporating hourly avoided costs increases the total benefits of air conditioning load reduction by more than $50/MWh. This type of hourly analysis is currently being used in California's avoided cost proceedings for energy efficiency.

Comparison of Avoided Costs for Three Implementation Approaches



Greater San Francisco Bay Area Avoided Distribution Costs



Avoided distribution capacity costs are also estimated by region in California. The Greater San Francisco Bay Area region is shown above in detail. In San Francisco and Oakland, avoided capacity costs are low because those areas are experiencing little load growth and have little need for new distribution investment. The Stockton area, on the other hand, is experiencing high growth and has significant new distribution infrastructure requirements.

- *Valuing Capacity Benefits.* The value of capacity benefits lies in the savings of not having to build or purchase new infrastructure, or make payments to capacity markets for system reliability. Because reliability of the nation's energy infrastructure is critical, it is difficult to make the decision to defer these investments without some degree of certainty that the savings will be achieved. Disregarding or undervaluing the transmission and generation capacity value of energy efficiency can, however, lead to underinvestment in energy efficiency. Realizing energy efficiency's capacity savings requires close coordination between efficiency and resource planners[1] to ensure that specific planned investments can actually be deferred as a result of energy efficiency programs. In the long term, lower load levels will naturally lead to lower levels of infrastructure requirements without a change in existing planning processes.

Targeted implementation of energy efficiency designed to defer or eliminate traditional reliability investments in the short term (whether generation, transmission, or distribution) requires that energy efficiency ramp up in time to provide sufficient peak load savings before the new infrastructure is needed. States with existing efficiency programs can use previous experience to estimate future adoption rates. In states that do not have previous experience with energy efficiency, however, the adoption rate of efficiency measures is difficult to estimate, making it hard to precisely quantify the savings that will be achieved by a certain date. Therefore, if the infrastructure project is critical for reliability, it is difficult to rely on energy as an alternative. The value of the targeted reductions and project deferrals can also be a challenge to quantify because of the uncertainty in the future investment needs and costs. However, there are examples of how to overcome this challenge, such as the Bonneville Power Administration (BPA) transmission planning process (described later). Vermont Docket 7081 is another collaborative process—initiated at the direction of the legislature—that is working on a new transmission planning process that will explicitly incorporate energy efficiency (Vermont Public Service Board, 2005). Both BPA and Vermont Docket 7081 stress the need to start well in advance of the need for reductions to allow the energy efficiency program to be developed and validated. In addition, by starting early, conventional alternatives can serve as a back-stop if needed. Starting early is also easier organizationally if alternatives are initiated before project proponents are vested in building new transmission lines.

The deferral of capacity expenditures can produce the same reliability level for customers. In cases when an energy efficiency program changes the expected reliability level (either higher or lower), the value to customers must be introduced as either a benefit or cost. A typical approach is to use the customer's Value of Lost Load (VOLL) as determined through Value of Service (VOS) studies and multiply by the expected change in customer outage hours. However, VOS studies based on customer surveys typically show wide-ranging results and are often difficult to substantiate.

In regions with established capacity markets, the valuation process is easier because the posted market prices are the value of capacity. The approach to value these benefits is therefore similar to the market price forecasting approach described to value energy benefits. Regional planning processes can also include energy efficiency in their resource planning. Regional electricity planning processes primarily focus on developing adequate resources to meet regional reliability criteria as defined in each of the North American Electric Reliability Council (NERC) regions. Establishing capacity and ancillary service market rules that allow energy efficiency and customer load response to participate can bring energy efficiency into the planning process. For example, Independent System Operator New England (ISO-NE) Demand Resources Working Group will be including

[1] The transmission planning process requires collaboration of regional stakeholders including transmission owners, utilities, and regulators. Distribution planning departments of electric utilities typically make the decisions for distribution-level and local transmission facilities. Planning and development of high-voltage transmission facilities on the bulk-supply system is done at the independent system operator (ISO)/RTO and North American Electric Reliability Council (NERC) regional levels. At a minimum, transmission adequacy must uphold the established NERC reliability standards.

energy efficiency and demand response as qualifying resources for the New England Forward Capacity Market. Another example is PJM Interconnection (PJM), which has recently made its Economic Load Response Program a permanent feature of the PJM markets (in addition to the Emergency Load Response Program that was permanently established in 2002) and has recently opened its Synchronized and Non-Synchronized Reserve markets to demand response providers.

Other Benefits

Energy efficiency provides several types of non-energy benefits not typically included in traditional resource planning. These benefits include environmental improvement, support for low-income customers, economic development, customer satisfaction and comfort, and other potential factors such as reduced costs for bill collection and service shut-offs, improvements in household safety and health, and increased property values. As an economic development tool, energy efficiency attracts and retains businesses, creates local jobs, and helps business competitiveness and area appeal.

Environmental benefits, predominantly air emissions reductions, might or might not have specific economic value, depending on the region and the pollutant. The market price of energy will include the producer's costs of obtaining required emission allowances (e.g., nitrogen oxides [NO_X], sulfur dioxide [SO_2]), and emission reduction equipment. Emissions of carbon dioxide (CO_2), also are affected by planning decisions of whether to consider the value of unregulated emissions. The costs of CO_2 were included in California's assessment of energy efficiency on the basis that these costs might become priced in the future and the expected value of future CO_2 prices should be considered when making energy efficiency investments.[2] Even without regulatory policy guidance, several utilities incorporate the estimated future costs of emissions such as CO_2 into their resources planning process to control the financial risks associated with future regulatory changes.[3] For example, Idaho Power Company includes an estimated future cost of CO_2 emissions in its resource planning, and in determining the cost-effectiveness of efficiency programs.

Many of these benefits do not accrue directly to the utility, raising additional policy and budgeting issues regarding whether, and how, to incorporate those benefits for planning purposes. Municipal utilities and governmental agencies have a stronger mandate to include a wider variety of non-energy benefits in energy efficiency planning than do investor-owned utilities (IOUs). Regulators of IOUs might also determine that these benefits should be considered. Many of the benefits are difficult to quantify. However, non-energy benefits can also be considered qualitatively when establishing the overall energy efficiency budget, and in developing guidelines for targeting appropriate customers (e.g., low income or other groups).

Setting Energy Efficiency Targets and Allocating Budget

One of the biggest barriers to energy efficiency is developing a budget to fund energy efficiency, particularly at utilities or in states that haven't had significant programs, historically. This is a not strictly a resource planning issue, but a regulatory, policy, and organizational issue as well. The two main organizational approaches for funding energy efficiency are resource planning processes, which establish the energy efficiency budget and targets within the planning process, and public goods-funded charges, which create a separate budget to support energy efficiency through a rate surcharge. There are successful examples of both approaches, as well as examples that use both mechanisms (California, BPA, PacifiCorp, and Minnesota).

Setting targets for energy efficiency resource savings and budgets is a collaborative process between resource planning staff, which evaluates cost-effectiveness, and other key stakeholders. Arguably, all energy efficiency

[2] California established a cost of $8/ton of CO2 in 2004, escalating at 5% per year (CPUC, 2005)

[3] For further discussion, see Bokenkamp, et al., 2005

measures identified as cost effective in an integrated resource plan (IRP) should be implemented.[4] In practice, a number of other factors must be considered. For example, the achievable level of savings and costs, expertise and labor, and ability to ramp up programs also affects the size, scope, and mix of energy efficiency programs. All of these considerations, plus the cost-effectiveness of energy efficiency, should be taken into account when establishing the funding levels for energy efficiency. The funding process might also require an iterative process that describes the alternative plans to regulators and other stakeholders. Some jurisdictions use a policy directive such as "all cost-effective energy efficiency" (California) while others allocate a fixed budget amount (New York), specify a fixed percentage of utility revenue (Minnesota and Oregon), or a target load reduction amount (Texas).

Implementation of a target for electric and gas energy savings, or Energy Efficiency Resources Standard (EERS) or Energy Efficiency Portfolio Standard (EEPS), such as the Energy Efficiency Goal adopted in Texas (PUCT Subst. R. §25.181), is an emerging policy tool adopted or being considered in a number of states (ACEEE, 2006). Some states have adopted standards with flexibility for how utilities meet such targets, such as savings by end users, improvements in distribution system efficiency, and market-based trading systems.

Resource Planning Process

If energy efficiency is considered as a resource, then the appropriate amount of energy efficient funding will be allocated through the utility planning process, based on cost-effectiveness, portfolio risk, energy and capacity benefits, and other criteria. Many utilities find that a resource plan that includes energy efficiency yields a lower cost portfolio, so overall procurement costs should decline more than the increase in energy efficiency program costs, and the established revenue requirement of the utility will be sufficient to fund the entire supply and demand-side resource portfolio.

A resource planning process that includes energy efficiency must also include a mechanism to ensure cost-recovery of energy efficiency spending. Most resource planning processes are collaborative forums to ensure that stakeholders understand and support the overall plan and its cost recovery mechanism. In some cases, utility costs might have to be shifted between utility functions (e.g., generation and transmission) to enable cost recovery for energy efficiency expenditures. For example, transmission owners might not see energy efficiency as a non-wires solution to transmission system deficiencies because it is unclear to what extent energy efficiency costs can be collected in the Federal Energy Regulatory Commission (FERC) transmission tariff. Therefore, even if energy efficiency is less costly than the transmission upgrade, it is unclear whether the transmission upgrade budget can be shifted to energy efficiency and still collected in rates. Another challenge for collecting efficiency funding in the transmission tariff is allocation of energy efficiency costs across multiple transmission owners, particularly if energy efficiency costs are incurred by a single transmission owner, while transmission costs are shared among several owners.

These examples demonstrate that in order to implement integrated resource planning, the regulatory agency responsible for determining rates must allow rates designed to support transmission, distribution, or other functions to be used for efficiency. The transmission companies in Connecticut have been allowed to include reliability-driven energy efficiency in tariffs, although this is noted as an emergency situation not to be repeated as a normal course of business. These interactions between regulatory policy and utility resource planning demonstrate that utilities cannot be expected to act alone in increasing energy efficiency through their planning process.

Public Purpose- or System Benefits Charge-Funded Programs

One way to fund energy efficiency is to develop a separate funding mechanism, collected in rates, to support

[4] Established cost-effectiveness tests, such as the total resource cost (TRC) test, are commonly used to determine the cost-effectiveness of energy efficiency programs. Material from Chapter 6: Energy Efficiency Program Best Practices describes these tests in more detail.

investment in energy efficiency. In deregulated markets with unbundled rates, this mechanism can appear as a separate customer charge, often referred to as a system benefits charge (SBC). Establishing a public purpose charge has the advantage of ensuring policy-makers that there is an allocation of funding towards energy efficiency, and can be necessary in deregulated markets where the delivery company cannot capture the savings of energy efficiency. This approach separates the energy efficiency budget from the resource planning process, however.

Developing a new rate surcharge or expanding an existing surcharge also raises many of the questions addressed in Chapter 2: Utility Ratemaking & Revenue Requirements. For example, are the customer segments paying into SBCs receiving a comparable level of energy efficiency assistance in return, or are the increases a cross-subsidy? Often, industrial customers prefer to implement their own efficiency rather than contribute to a pool. Also, if the targets are used to set shareholder incentives, the incentives should be appropriate for the aggressiveness of the program. Additionally, because the targeted budget allocation in public purpose-funded programs is often set independently of the utility's overall resource planning process (and is not frequently changed), utilities might not have funding available to procure all cost-effective savings derived from energy efficiency measures. This type of scenario can result in potentially higher costs for customers than would occur if each cost-effective efficiency opportunity were pursued.

Overcoming Challenges: Alternative Approaches

Successful incorporation of energy efficiency into the resource planning process requires utility executives, resource planning staff, regulators, and other stakeholders to value energy efficiency as a resource, and to be committed to making it work within the utility or regional resource portfolio. To illustrate approaches to overcoming these barriers, we highlight several successful energy efficiency programs by California, the New York State Energy Research and Development Authority (NYSERDA), BPA, Minnesota, Texas, and PacifiCorp. The energy efficiency programs in these six regions demonstrate several different ways to incorporate energy efficiency into planning processes; in each example, the economics generally work well for efficiency programs.

The primary driver of energy efficiency in planning is the low levelized cost of energy savings. Table 3-1 shows the reported levelized cost of electricity and natural gas efficiency from three of the regions surveyed. The reported utility cost of efficiency ranges between $0.01/kilowatt-hour (kWh) and $0.03/kWh for Pacific Gas & Electric (PG&E), NYSERDA, and the Northwest Power and Conservation Council (NWPCC). When including both utility program costs and customer costs, the range is $0.03/kWh to $0.05/kWh. The range of reported benefits for electric energy efficiency is from $0.06/kWh to $0.08/kWh. For natural gas, only P&GE reported specific natural gas efficiency measures; these show similarly low levelized costs relative to benefits.

Table 3-1: Levelized Costs and Benefits From Four Regions

	Electric ($/kWh)			Natural Gas ($/therm)		
	Utility Cost	Utility & Customer Cost	Benefit	Utility Cost	Utility & Customer Cost	Benefit
PG&E [1]	0.03	0.05	0.08	0.28	0.56	0.81
NYSERDA [2]	0.01	0.03	0.06	N/A	N/A	N/A
NWPCC [3]	0.024	N/A	0.060	N/A	N/A	N/A
Texas [4]	0.025 [5]	N/A	0.060 [6]	N/A	N/A	N/A

1 PG&E, 2005

2 NYSERDA, 2005

3 NWPCC, 2005

4 Calculated based on Texas Utility Avoided Cost (PUCT Substantive Rule §25.18 of 2000). $0.0268/kWh for energy and $78.50/kW-year for capacity converted to $/kWh based on assumption of 10-year measure life, load factor of 26.4 percent, which is calculated from Texas' 2004 efficiency-based reductions of 193 MW of peak demand and 448 GWh of energy (Frontier Associates, 2005).

5 Based on 2004 spending of $87 million, 448 GWh annual. Assumed life of 10 years (PUCT Substantive Rule §25.181 of 2000).

6 Based on Public Utility Commission of Texas (PUCT) Deemed Avoided Costs of $0.0268/kWh for energy and $78.50/kW-year for capacity, 448GWh and 193MW of peak load reduction.

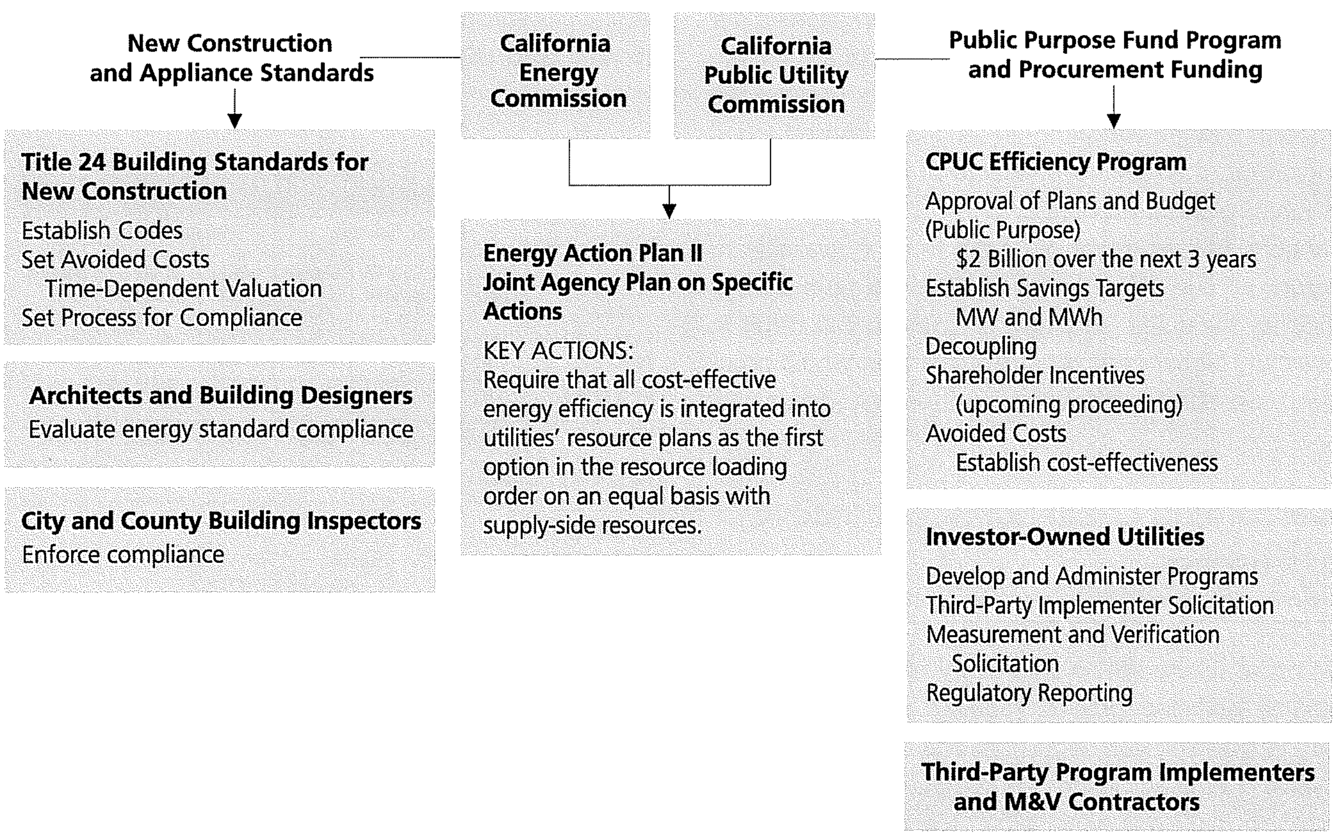
California

California has had a continued commitment to energy efficiency since the late 1970s. Two major efforts are currently being coordinated in the state that address energy use in new buildings as well as efficiency upgrades in existing buildings. Figure 3-2 shows the policy structure, with the California Energy Commission (CEC) leading the building codes and standards process, and the California Public Utility Commission (CPUC) leading the IOU and third-party administered efficiency programs. Jointly, the agencies publish the Energy Action Plan that explicitly states a goal to integrate "all cost-effective energy efficiency." Recently, the CPUC approved an efficiency budget of $2 billion over the next three years to serve a population of approximately 35 million.

The process for designing and implementing efficiency programs in California by the IOUs is to develop the programs (either by the utility or through third-party solicitation), evaluate cost-effectiveness, establish and gain approval for the program funding, and evaluate the program's success through M&V. Figure 3-2 illustrates this approach.

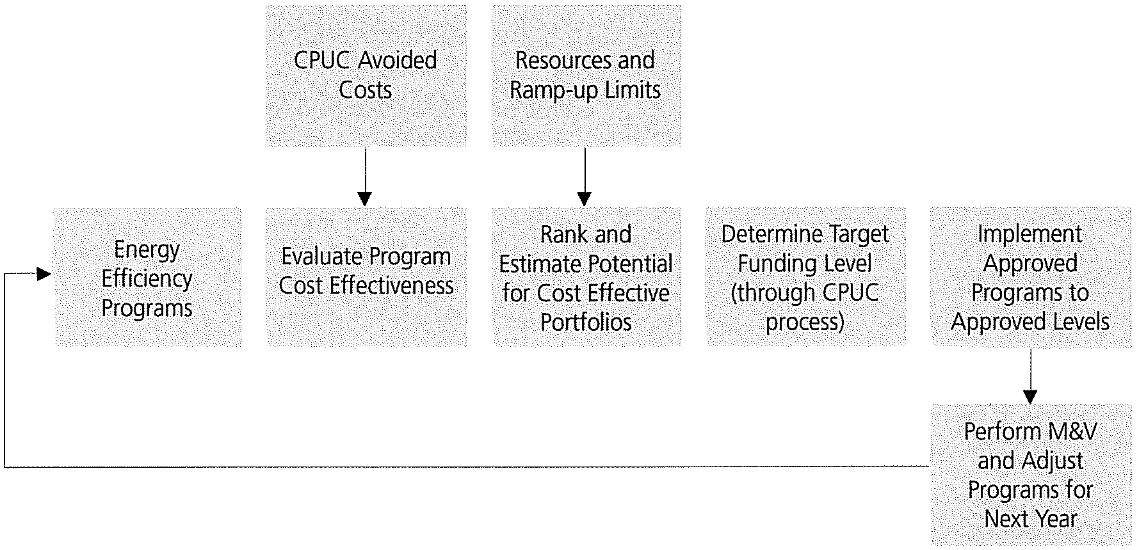
Table 3-2 describes how California addresses barriers for incorporating energy efficiency in planning for the IOU process.

Figure 3-2. California Efficiency Structure Overview



Source: Energy and Environmental Economics, Inc.

Figure 3-3. California Investor-Owned Utility (IOU) Process



Source: Energy and Environmental Economics, Inc.

Table 3-2. Incorporation of Energy Efficiency in California's Investor-Owned Utilities' Planning Processes

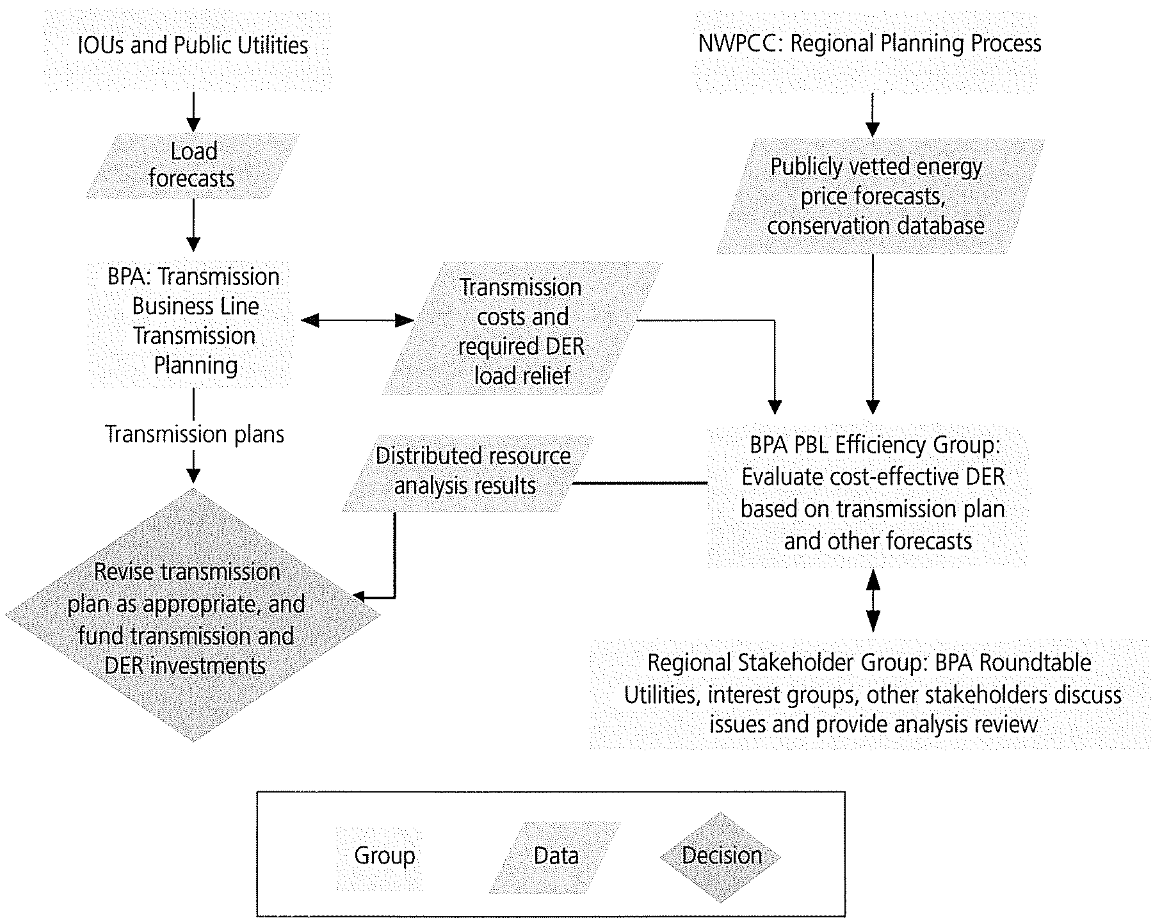
Barriers	California CPUC-Administered Programs
A. Determining the Value of Energy Efficiency	
Energy Procurement	
Estimated energy savings	Customer adoption rates are forecast into the energy efficiency plans with monthly or quarterly reporting of program success for tracking.
Valuing energy savings	Energy savings are based on market prices of future electricity and natural gas, adjusted by loss factors. Emission savings are based on expected emission rates of marginal generating plants in each hour (electricity) or emissions for natural gas.
Capacity & Resource Adequacy	
Estimating capacity savings	Capacity savings are evaluated using the load research data for each measure.
Valuing capacity benefits	Each capacity-related value is estimated by climate zone of the state and incorporated into an "all-in" energy value. Transmission and distribution capacity for electricity is allocated based on weather in each climate zone, and by season for natural gas. California's energy market (currently) includes both energy and capacity so there is no explicit capacity value for electric generation.
Factors in achieving benefits	Capacity benefits are based on the best forecast of achieved savings. There is no explicit link between forecasted benefits of energy efficiency and actual capacity savings.
Other Benefits	
Incorporating non-energy benefits	Non-energy benefits are considered in the development of the portfolio of energy efficiency, but not explicitly quantified in the avoided cost calculation.
B. Setting Targets and Allocating Budget	
Quantity of energy efficiency to implement	CPUC has approved budget and targets for the state's efficiency programs, which are funded through both a public purpose charge and procurement funding.
Estimating program effectiveness	A portion of the public purpose funds are dedicated to evaluation, measurement, and verification with the goal of improving the understanding and quantification of savings and benefit estimates.
Institutional difficulty in reallocating budget	By using public purpose funds, budget doesn't have to be reallocated from other functions for energy efficiency.
Cost expenditure timing vs. benefits	Capacity benefits are based on the best forecast of achieved savings.
Ensuring the program costs are recaptured	CPUC requires that the utilities integrate energy efficiency into their long-term procurement plans to address this issue.

Bonneville Power Administration Transmission Planning and Regional Roundtable

In the Northwest, BPA has been leading an industry roundtable to work with distribution utilities, local and state government, environmental interests, and other stakeholders to incorporate energy efficiency and other distributed energy resources (DER) into transmission planning. DER includes energy efficiency as well as distribution generation and other nonwires solutions. Figure 3-4 illustrates the analysis approach and data sources. Within BPA, the Transmission Business Line (TBL) works with the energy efficiency group in Power Business Line (PBL) to develop an integrated transmission plan. The process includes significant stakeholder contributions in both input data assumptions (led by NWPCC) and in reviewing the overall analysis at the roundtable.[5]

Table 3-3 describes how BPA works with stakeholders to address barriers for incorporating energy efficiency in planning processes.

Figure 3-4. BPA Transmission Planning Process



Source: Energy and Environmental Economics, Inc.

[5] NWPCC conducts regional energy efficiency planning. More information can be found at <http://www.nwcouncil.org>.

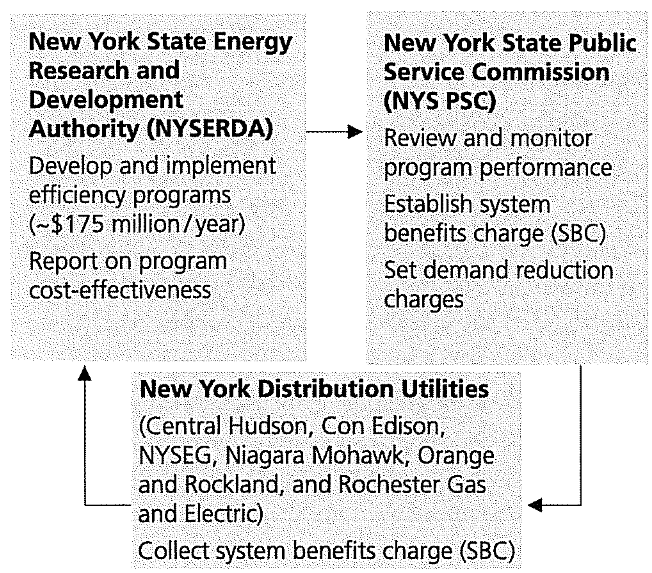
Table 3-3. Incorporation of Energy Efficiency in BPA's Planning Processes	
Barriers	**BPA-Administered Programs**
A. Determining the Value of Energy Efficiency	
Energy Procurement	
Estimated energy savings	The process uses the NWPCC database to define the measure impact and costs. NWPCC maintains a publicly available regional efficiency database that is well regarded and has its own process for stakeholder collaboration. Adoption rates are estimated based on a range of historical program success.
Valuing energy savings	Energy savings are valued based on the NWPCC long-run forecast of energy value for the region, plus marginal losses.
Capacity & Resource Adequacy	
Estimating capacity savings	Capacity savings are based on expected NWPCC efficiency measure coincident peak impacts.
Valuing capacity benefits	The deferral value of transmission investments is used to evaluate the transmission capacity value, which is the focus of these studies. The approach is to calculate the difference in present value revenue requirement before and after the energy efficiency investment (Present Worth Method).
Factors in achieving benefits	The BPA energy efficiency and transmission planning staff work together to ensure that the revised plan with Non-Construction Alternatives (NCAs) satisfies reliability criteria. Ultimately the decision to defer transmission and rely on NCAs will be approved by transmission planning.
Other Benefits	
Incorporating non-energy benefits	The analysis includes an evaluation of the environmental externalities, but no other non-energy benefits.
B. Setting Targets and Allocating Budget	
Quantity of energy efficiency to implement	The target for NCAs is established by the amount of load that must be reduced to defer the transmission line and maintain reliability. This target is driven by the load growth forecasts of the utilities in the region.
Estimating program effectiveness	BPA has been doing demonstrations and pilots of high-potential NCAs to refine the estimates of program penetration, cost, necessary timeline for achieving load reductions, customer acceptance, and other factors. The results of these pilots will help to refine the estimates used in planning studies.
Institutional difficulty in reallocating budget	If NCAs have lower cost than transmission, transmission capital budget will be reallocated to support NCA investments up to the transmission deferral value. Additional costs of NCAs that are justified based on energy value are supported by other sources (BPA energy efficiency, local utility programs, and customers).
Cost expenditure timing vs. benefits	Both transmission and NCAs require upfront investments so there is no significant time lag between costs and benefits. The transmission savings benefit is achieved concurrently with the decision to defer the transmission investment. Energy benefits, on the other hand, occur over a longer timeframe and are funded like other energy efficiency programs.
Ensuring the program costs are recaptured	By developing an internal planning process to reallocate budget, it is easier to ensure that the savings occur.

New York State Energy Research and Development Authority (NYSERDA)

In the mid-1990s, New York restructured the electric utilities and moved responsibility for implementing energy efficiency programs to the NYSERDA. The following figure shows an overview of the NYSERDA process. The programs are funded through the SBC funds (approximately $175 million per year), and NYSERDA reports on the program impact and cost-effectiveness to the New York State Public Service Commission (NYS PSC) annually.

Table 3-4 describes how NYSERDA addresses the barriers to implementing energy efficiency.

Figure 3-5. New York Efficiency Structure Overview



Source: Energy and Environmental Economics, Inc.

Table 3-4. Incorporation of Energy Efficiency in NYSERDA's Planning Processes	
Barriers	**NYSERDA-Administered Programs**
A. Determining the Value of Energy Efficiency	
Energy Procurement	
Estimating energy savings	NYSERDA internally develops estimates of savings for individual energy efficiency programs and the portfolio in aggregate. In addition, NYSERDA accounts for free-riders and spillover effects ("net to gross" ratio) when estimating energy savings. Savings estimates are verified and refined with an M&V program.
Valuing energy savings	A long-run forecast of electricity demand is developed using a production simulation model, which is then calibrated to market prices. An estimate of reduced market prices due to decreased demand is also included as a benefit.
Capacity & Resource Adequacy	
Estimating capacity savings	Similar to energy savings, capacity savings are estimated for individual energy efficiency programs and the portfolio in aggregate. Savings estimates are verified and refined with an M&V program.
Valuing capacity benefits	The value of generation capacity in New York is established by examining historical auction clearing prices in the NYISO's unforced capacity market. The baseline values are then escalated over time using a growth rate derived from NYSERDA's electric system modeling results. These capacity costs are used to value those NYSERDA programs that effectively lower system peak demand.
Factors in achieving benefits	The capacity value is included as the best estimate of future capacity savings by New York utilities. There is no direct link, however, between the forecasted savings and the actual change in utility procurement budgets.
Other Benefits	
Incorporating non-energy benefits	The cost-effectiveness of NYSERDA programs is estimated using four scenarios of increasing NEB levels from (1) energy savings benefits, (2) adding market price effects, (3) adding non-energy benefits, and (4) adding macro-economic effects of program spending.
B. Setting Energy Efficiency Targets	
Quantity of energy efficiency to implement	The overall size of the NYSERDA program is determined by the aggregate funding level established by the NYS PSC. NYSERDA, with advice from the SBC Advisory Group, recommends specific sub-program funding levels for approval by the staff at NYS PSC.
Estimating program effectiveness	NYSERDA prepares an annual report on program effectiveness including estimated and verified impacts and cost effectiveness, which is then reviewed by the SBC Advisory Group and submitted to the NYS PSC.
Institutional difficulty in reallocating budget	By establishing a separate state research and development authority to administer energy efficiency, the institutional problems of determining and allocating budget towards energy efficiency are eliminated. NYSERDA is supported primarily by SBCs collected by the utilities at the direction of NYS PSC.
Cost expenditure timing vs. benefits	Similarly, by funding the programs through an SBC, the customers are directly financing the program, thereby making the timing of benefits less important.
Ensuring the program costs are recaptured	Forecasts of savings are based on the best estimate of future savings. There is no direct link to ensure these savings actually occur.

Minnesota

The Minnesota legislature passed the Conservation Improvement Program (CIP) in 1982. State law requires that (1) electric utilities that operate nuclear-power plants devote at least 2 percent of their gross operating revenue to CIP, (2) other electric utilities devote at least 1.5 percent of their revenue, and (3) natural gas utilities devote at least 0.5 percent. Energy is supplied predominantly by two utilities: Xcel, which provides 49 percent of the electricity and 25 percent of the natural gas, and CenterPoint Energy, which provides 45 percent of the natural gas. Facilities with a peak electrical demand of at least 20 megawatts (MW) are permitted to opt out of CIP and avoid paying the program's rate adjustment in their electric and natural gas bills (10 facilities have done so). While the Minnesota Department of Commerce oversees the CIP programs of all utilities in the state, the department only has the authority to order changes in the programs of the IOUs.

Utilities are required to file an IRP every 2 years, using 5-, 10- and 15-year planning horizons to determine the need for additional resources. The statutory emphasis is on demand-side management (DSM) and renewable resources. A utility must first show why these resources will not meet future needs before proposing traditional utility investments. The plans are reviewed and approved by the Minnesota Public Utilities Commission. CIP is the

Table 3-5. Incorporation of Energy Efficiency in Minnesota's Planning Processes	
Barriers	**Minnesota-Administered Programs**
A. Determining the Value of Energy Efficiency	
Energy Procurement	
Estimating energy savings	Energy savings and avoided costs are determined independently by each utility, resulting in a wide range of estimates that are not consistent. Energy costs are considered a trade secret and not disclosed publicly.
Valuing energy savings	
Capacity & Resource Adequacy	
Estimating capacity savings	Capacity savings and avoided costs are determined independently by each utility, resulting in a wide range of estimates that are not consistent. Power plant, transmission, and distribution costs are considered trade secrets and are not disclosed publicly.
Valuing capacity benefits	
Factors in achieving benefits	There is no direct link between the forecasted capacity savings and the actual change in utility procurement budgets.
Other Benefits	
Incorporating non-energy benefits	Differences in the utilities' valuation methods produce varying estimates. In addition, the Department of Commerce incorporates an externality avoided cost in the electric societal cost benefit test, providing utilities with values in $/ton for several emissions, which the utilities translate to amounts in $/MWh based on each utility's emissions profile.
B. Setting Targets and Allocating Budget	
Quantity of energy efficiency to implement	The Department of Commerce approves budget and targets for each utility. Funding levels are determined by state law, which requires 0.5 percent to 2 percent of utility revenues be dedicated to conservation programs, depending on the type of utility.
Estimating program effectiveness	Program effectiveness is handled by each utility. Minnesota's IOUs rely on the software tools DSManager and BENCOST to measure electric and gas savings respectively.
Institutional difficulty in reallocating budget	Budget is not reallocated from other functions. Funding is obtained via a surcharge on customer bills.
Cost expenditure timing vs. benefits	By using a percentage of revenue set-aside, utility customers are directly financing the program; therefore timing of benefits is not critical.
Ensuring the program costs are recaptured	State law requires that each utility file an IRP with the Public Utilities Commission. The conservation plans approved by the Department of Commerce are the primary mechanism by which utilities meet conservation targets included in their IRPs.

primary mechanism by which the electric utilities achieve the conservation targets included in their IRPs.

The Department of Commerce conducts a biennial review of the CIP plan for each investor-owned utility. Interested parties may file comments and suggest alternatives before the department issues a decision approving or modifying the utility's plan. Utilities that meet or exceed the energy savings goals established by the Department of Commerce receive a financial bonus, which they are permitted to collect through a rate increase. Both electric utilities have exceeded their goals for the last several years. Table 3-5 describes how the Minnesota Department of Commerce addresses barriers to implementing energy efficiency.

Texas

Texas Senate Bill 7 (1999), enacted in the 1999 Texas legislature, mandates that at least 10 percent of an investor-owned electric utility's annual growth in electricity demand be met through energy efficiency programs each year. The Public Utility Commission of Texas (PUCT) Substantive Rule establishes procedures for meeting this legislative mandate, directing the transmission and distribution (T&D) utilities to hire third-party energy efficiency providers to deliver energy efficiency services to every customer class, using "deemed savings" estimates for each energy efficiency measure (PUCT, 2000). Approved program costs are included in the IOU's transmission and distribution rates, and expenditures are reported separately in the IOU's annual energy efficiency report to the PUCT. Actual energy and capacity savings are verified by independent experts chosen by the PUCT. Incentives are based on prescribed avoided costs, which are set by

Table 3-6. Incorporation of Energy Efficiency in Texas' Planning Processes	
Barriers	**Texas-Administered Programs**
A. Determining the Value of Energy Efficiency	
Energy Procurement	
Estimating energy savings	Energy savings are based on either deemed savings or through M&V. All savings estimates are subject to verification by a commission-appointed M&V expert.
Valuing energy savings	Avoided costs shall be the estimated cost of new gas turbine, which for energy was initially set in PUCT section 25.181-5 to be $0.0268 /kWh saved annually at the customer's meter.
Capacity & Resource Adequacy	
Estimating capacity savings	Capacity savings are based on either deemed savings or through M&V. All savings estimates are subject to verification by a commission-appointed M&V expert.
Valuing capacity benefits	Avoided costs shall be the estimated cost of new gas turbine, which for capacity was initially set in PUCT section 25.181-5 to be $78.5/kW saved annually at the customer's meter.
Other Benefits	
Incorporating non-energy benefits	Environmental benefits of up to 20 percent above the cost effectiveness standard can be applied for projects in an area that is not in attainment of ambient air quality standards.
B. Setting Energy Efficiency Targets	
Quantity of energy efficiency to implement	Senate Bill 7 (SB7) mandates that, beginning in 2004, at least 10 percent of an investor-owned electric utility's annual growth in electricity demand be met through energy efficiency programs each year (based on historic five-year growth rate for the firm). Funding for additional programs is available if deemed cost-effective.
Estimating program effectiveness	Each year, the utility submits to the PUCT an energy efficiency plan for the year ahead and an energy efficiency report for the past year. The plan must be approved by the commission, and the year-end report must include information regarding the energy and capacity saved. Also, independent M&V experts selected by the commission to verify the achieved savings as reported in each utility's report.
Institutional difficulty in reallocating budget	Funds required for achieving the energy efficiency goal are included in transmission and distribution rates, and energy efficiency expenditures are tracked separately from other expenditures.
Cost expenditure timing vs. benefits	By using a percentage of revenue set aside, utility customers directly finance the program; therefore timing of benefits is not critical.
Ensuring the program costs are recaptured	The annual energy efficiency report submitted by the IOU to the PUCT includes energy and capacity savings, program expenditures, and unspent funds. There is no verification that the estimated avoided costs are captured in utility savings.

the PUCT. El Paso Electric Company will be included in the program beginning with an efficiency target of 5 percent of growth in 2007 and 10 percent of growth in 2008.

The 2004 report on Texas' program accomplishments highlights the level of savings and success of the program: "In 2004, the investor-owned utilities in Texas achieved their statewide goals for energy efficiency once again. 193 MW of peak demand reduction was achieved, which was 36% above its goal of 142 MW. In addition, 448 gigawatt-hours (GWh) of demand eduction was achieved. These energy savings correspond to a reduction of 1,460,352 pounds of nitrogen oxide (NO_X) emissions. Incentives or rebates were provided to project sponsors to offset the costs of a variety of energy efficiency improvements. Two new energy efficiency programs were voluntarily introduced by the Texas utilities." Table 3-6 describes how Texas utilities address barriers to implementing energy efficiency.

PacifiCorp

PacifiCorp is an investor-owned utility with more than 8,400 MW of generation capacity that serves approximately 1.6 million retail customers in portions of Utah, Oregon, Wyoming, Washington, Idaho, and California. PacifiCorp primarily addresses its energy efficiency planning objectives as part of its IRP process. Efficiency-based measures are evaluated based on their effect on the overall cost of PacifiCorp's preferred resource portfolio, defined as the overall supply portfolio with the best balance of cost and risk.

Additionally, some states that are in PacifiCorp's service territory, such as Oregon and California, also mandate that the company allocate funds for efficiency under related statewide public goods regulations. "In Oregon, SB 1149 requires that investor-owned electric companies collect from all retail customers a public purpose charge equal to 3% of revenues collected from customers. Of this amount, 57% (1.7% of revenues) goes toward Class 2 [energy efficiency-based] demand side management (DSM). The Energy Trust of Oregon (ETO) was set up to determine the manner in which public purpose funds will be spent"(PacifiCorp, 2005). Using the IRP model to determine investment in energy efficiency, however, PacifiCorp allocates more money to efficiency than required by state statute.

As of the 2004 IRP, PacifiCorp planned to implement a base of 250 average megawatts (aMW) of energy efficiency, and to seek an additional 200 aMW of new efficiency programs if cost-effective options could be identified. PacifiCorp models the impact of energy efficiency as a shaped load reduction to their forecasted load, and computes the change in supply costs with, and without, the impact of DSM. This approach allows different types of DSM to receive different values based on the alternative supply costs in different parts of the PacifiCorp service territory. For example, the IRP plan indicates that "residential air conditioning decrements produce the highest value [in the East and West].

Table 3-7. Incorporation of Energy Efficiency in PacifiCorp's Planning Processes

Barriers	PacifiCorp-Administered Programs
A. Determining the Value of Energy Efficiency	
Energy Procurement	
Estimating energy savings	The load forecast in the IRP is reduced by the amount of energy projected to be saved by existing programs, existing programs that are expanded to other states, and new cost-effective programs that resulted from the 2003 DSM request for proposals (RFPs). These load decrements have hourly shapes based on the types of measures installed for each program.
Valuing energy savings	Efficiency-based (or Class 2) DSM programs are valued based on cost effectiveness from a utility cost test perspective, minimizing the present value revenue requirement. The IRP (using the preferred portfolio of supply-side resources) is run with and without these DSM decrements, and their value in terms of cost-savings is calculated as the difference in revenue requirements for that portfolio with and without these Class 2 load reductions.
Capacity & Resource Adequacy	
Estimating capacity savings	PacifiCorp explicitly evaluates the capacity value of dispatchable and price-based DSM, or 'Class 1' DSM, and the ability to hit target reserve margins in the system with these resources. The IRP resulted in a recommendation to defer three different supply-side projects. The capacity benefits of more traditional energy efficiency programs are not explicitly evaluated; however, the planned energy efficiency reductions are used to update the load forecast in the next year's IRP, which could result in additional deferrals.
Valuing capacity benefits	Capacity savings are valued at the forecasted costs of displaced generation projects. By integrating the evaluation of DSM into the overall portfolio, the value of energy efficiency is directly linked to specific generation projects. It does not appear that PacifiCorp evaluates the potential for avoided transmission and distribution capacity.
Other Benefits	
Incorporating non-energy benefits	Non-energy benefits are considered in the selection of a preferred portfolio of resources, but the non-energy benefits of efficiency are not explicitly used in the IRP.
B. Setting Energy Efficiency Targets	
Quantity of energy efficiency to implement	As part of the 2004 IRP, PacifiCorp determined that a base of 250 aMW of efficiency should be included in the goals for the next 10 years, and that an additional 200 aMW should be added if cost-effective programs could be identified.
Estimating program effectiveness	Measurement methodology for new projects is not explicitly identified in the IRP, but values from existing programs and the forecasted load shapes for PacifiCorp's customers will be used to predict benefits.
Institutional difficulty in reallocating budget	Funding is integrated into the overall process of allocating budget to resource options (both supply side and demand side), and faces only challenges associated with any resource option, namely proof of cost-effective benefit to the resource portfolio.
Cost expenditure timing vs. benefits	The IRP process for PacifiCorp seeks to gain the best balance of cost and risk using the present value of revenue requirements, which accounts for timing issues associated with any type of resource evaluated, including efficiency.
Ensuring the program costs are recaptured	Successive IRPs will continue to evaluate the cost-effectiveness of energy efficiency programs to determine their effect on overall costs of the resource portfolio.

Programs with this end use impact provide the most value to PacifiCorp's system because they reduce demand during the highest use hours of the year, summer heavy load hours. The commercial lighting and system load shapes with the highest load factors provide the lowest avoided costs." It does not appear that PacifiCorp recomputes the overall risk of its portfolio with increased energy efficiency. Table 3-7 describes how PacifiCorp addresses barriers to implementing energy efficiency.

Key Findings

This section describes the common themes in the approaches used to navigate and overcome the barriers to incorporating energy efficiency in the planning process. While there are many approaches to solving each issue, the following key findings stand out:

- *Cost and Savings Data for Energy Efficiency Measures Are Readily Available.* Given the long history of energy efficiency programs in several regions, existing resources to assist in the design and implementation of energy efficiency programs are widely available. Both California and the Northwest maintain extensive, publicly available online databases of energy efficiency measures and impacts: the Database for Energy Efficiency Resources (DEER) in California[6] and NWPCC Database in the Northwest.[7] DEER includes both electricity and natural gas measures while NWPCC contains only electricity measures. These databases incorporate a number of factors affecting savings estimates, including climate zones, building type, building vintage, and customer usage patterns. Energy efficiency and resource planning studies containing detailed information on efficiency measures are available for regions throughout the United States. It is often possible to adjust existing data for use in a specific utility service area with relatively straightforward assumptions.

- *Energy, Capacity, and Non-Energy Benefits Can Justify Robust Energy Efficiency Programs.* Energy savings alone are usually more than sufficient to justify and fund a wide range of efficiency measures for electricity and natural gas. However, the capacity and non-energy benefits of energy efficiency are important factors to consider in assessing energy efficiency measures on an equal basis with traditional utility investments. In practice, policy, budget, expertise, and human resources are the more limiting constraints to effectively incorporating energy efficiency into planning.

  — Estimating the quantity and value of energy savings is relatively straightforward. Well-established methods for estimating the quantity and value of energy savings have been used in many regions and forums. All of the regional examples for estimating energy and capacity savings for energy efficiency evaluate the savings for an individual measure using either measurements or engineering simulation, and then aggregate these by the expected number of customers who will adopt the measure. Both historical and forward market prices are readily available, particularly for natural gas where long-term forward markets are more developed.

  — Estimating capacity savings is more difficult, but challenges are being overcome. Capacity savings depend more heavily on regional weather conditions and timing of the peak loads and, therefore, are difficult to estimate. Results from one region do not readily transfer to another. Also, publicly available market data for capacity are not as readily available as for energy, even though the timing and location of the savings are critical. Because potential capacity savings are larger for electricity energy efficiency than natural gas, capturing capacity value is a larger issue for electric utilities. Production simulation can explicitly evaluate the change in power plant investment and impact of such factors as re-dispatch due to transmission constraints, variation in load growth,

[6] The DEER Web site, description, and history can be found at: http://www.energy.ca.gov/deer/. The DEER database of measures can be found at: http://eega.cpuc.ca.gov/deer/.

[7] The NWPCC Web site, comments, and efficiency measure definition can be found at: http://www.nwcouncil.org/comments/default.asp.

and other factors. But these models are analytically complex and planning must be tightly integrated with other utility planning functions to accurately assess savings. These challenges can and have been overcome in different ways in regions with a long track-record of energy efficiency programs (e.g., California, BPA, New York).

— Estimating non-energy benefits is an emerging approach in many jurisdictions. Depending on the jurisdiction, legislation and regulatory commission policies might expressly permit, and even require, the consideration of non-energy benefits in cost-effectiveness determinations. However, specific guidelines regarding the quantification and inclusion of non-energy benefits are still under discussion or in development in most jurisdictions. The consideration of both non-energy and capacity benefits of energy efficiency programs is relatively new, compared to the long history of valuing energy savings.

- *A Clear Path to Funding Is Needed to Establish a Budget for Energy Efficiency Resources.* There are three main approaches to funding energy efficiency investments: 1) utility resource planning processes, 2) public purpose funding, and 3) a combination of both. In a utility resource planning process, such as the BPA non-construction alternatives process, efficiency options for meeting BPA's objectives are compared to potential supply-side investments on an equal basis when allocating the available budget. In this type of resource planning process, budget is allocated to efficiency measures from each functional area according to the benefits provided by efficiency programs. The advantage of this approach is that the budget for efficiency is linked directly to the savings it can achieve; however, particularly in the case of capacity-related benefits, which have critical timing and load reduction targets to maintain reliability, it is a difficult process.

  The public purpose funding and SBC approaches in New York, Minnesota, and other states are an alternative to budget reallocation within the planning process. In California, funding from both planning processes and public purpose funding is used. Public purpose funds do not have the same direct link to energy savings, so programs might not capture all the savings attributed to the program. Funding targets might be set before available efficiency options have been explored, so if other cost-effective efficiency measures are later identified, additional funding might not be available. This situation can result in customer costs being higher than they would have been if all cost-effective efficiency savings opportunities had been supported. Using public purpose funding significantly simplifies the planning process, however, and puts more control over the amount of energy efficiency in the control of regulators or utility boards. As compared to resource planning, far less time and effort are required on the part of regulators or legislators to direct a specific amount of funding to cost-effective efficiency programs.

- *Integrate Energy Efficiency Early in the Resource Planning Process.* In order to capture the full value of deferring the need for new investments in capacity, energy efficiency must be integrated early in the planning process. This step will avoid sunk investment associated with longer lead-time projects. Efficiency should also be planned to target investments far enough into the future so that energy efficiency programs have the opportunity to ramp up and provide sufficient load reduction. This timeline will allow the utility to build expertise and establish a track record for energy efficiency, as well as be able to monitor peak load reductions. Starting early also allows time to gain support of the traditional project proponents before they are vested in the outcome.

Recommendations and Options

The National Action Plan for Energy Efficiency Leadership Group offers the following recommendations as ways to overcome many of the barriers to energy efficiency in resource planning, and provides a number of options for consideration for consideration by utilities, regulators and stakeholders *(as presented in the Executive Summary)*.

Recommendation: Recognize energy efficiency as a high priority energy resource. Energy efficiency has not been consistently viewed as a meaningful or dependable resource compared to new supply options, regardless of its demonstrated contributions to meeting load growth. Recognizing energy efficiency as a high-priority energy resource is an important step in efforts to capture the benefits it offers, and lower the overall cost of energy services to customers. Based on jurisdictional objectives, energy efficiency can be incorporated into resource plans to account for the long-term benefits from energy savings, capacity savings, potential reductions of air pollutants and greenhouse gases, as well as other benefits. The explicit integration of energy efficiency resources into the formalized resource planning processes that exist at regional, state, and utility levels can help establish the rationale for energy efficiency funding levels and for properly valuing and balancing the benefits. In some jurisdictions, these existing planning processes might need to be adapted or even created to meaningfully incorporate energy efficiency resources into resource planning. Some states have recognized energy efficiency as the resource of first priority due to its broad benefits.

Options to Consider.

- Establishing policies to establish energy efficiency as a priority resource.
- Integrating energy efficiency into utility, state, and regional resource planning activities.
- Quantifying and establishing the value of energy efficiency, considering energy savings, capacity savings, and environmental benefits, as appropriate.

Recommendation: Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource. Energy efficiency programs are most successful and provide the greatest benefits to stakeholders when appropriate policies are established and maintained over the long-term. Confidence in long-term stability of the program will help maintain energy efficiency as a dependable resource compared to supply-side resources, deferring or even avoiding the need for other infrastructure investments, and maintain customer awareness and support. Some steps might include assessing the long-term potential for cost-effective energy efficiency within a region (i.e., the energy efficiency that can be delivered cost-effectively through proven programs for each customer class within a planning horizon); examining the role for cutting-edge initiatives and technologies; establishing the cost of supply-side options versus energy efficiency; establishing robust M&V procedures; and providing for routine updates to information on energy efficiency potential and key costs.

Options to Consider:

- Establishing appropriate cost-effectiveness tests for a portfolio of programs to reflect the long-term benefits of energy efficiency.
- Establishing the potential for long-term, cost-effective energy efficiency savings by customer class through proven programs, innovative initiatives, and cutting-edge technologies.
- Establishing funding requirements for delivering long-term, cost-effective energy efficiency.
- Developing long-term energy saving goals as part of energy planning processes.
- Developing robust M&V procedures.
- Designating which organization(s) is responsible for administering the energy efficiency programs.
- Providing for frequent updates to energy resource plans to accommodate new information and technology.

Recommendation: Broadly communicate the benefits of, and opportunities for, energy efficiency. Experience shows that energy efficiency programs help customers save money and contribute to lower cost energy systems. But these benefits are not fully documented nor recognized by customers, utilities, regulators, or policymakers. More effort is needed to establish the business case for energy efficiency for all decision-makers and to show how a well-designed approach to energy efficiency can benefit customers, utilities, and society by (1) reducing customers' bills over time, (2) fostering financially healthy utilities (e.g., return on equity, earnings per share, and debt coverage ratios unaffected), and (3) contributing to positive societal net benefits overall. Effort is also necessary to educate key stakeholders that although energy efficiency can be an important low-cost resource to integrate into the energy mix, it does require funding just as a new power plant requires funding.

Options to Consider:

- Establishing and educating stakeholders on the business case for energy efficiency at the state, utility, and other appropriate level addressing customer, utility, and societal perspectives.

- Communicating the role of energy efficiency in lowering customer energy bills and system costs and risks over time.

Recommendation: Provide sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective. Energy efficiency programs require consistent and long-term funding to effectively compete with energy supply options. Efforts are necessary to establish this consistent long-term funding. A variety of mechanisms has been and can be used based on state, utility, and other stakeholder interests. It is important to ensure that the efficiency program providers have sufficient long-term funding to recover program costs and implement the energy efficiency measures that have been demonstrated to be available and cost-effective. A number of states are now linking program funding to the achievement of energy savings.

Options to Consider:

- Deciding on and committing to a consistent way for program administrators to recover energy efficiency costs in a timely manner.

- Establishing funding mechanisms for energy efficiency from among the available options, such as revenue requirements or resource procurement funding, SBCs, rate-basing, shared-savings, incentive mechanisms, etc.

- Establishing funding for multi-year periods.

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4: Business Case for Energy Efficiency

A well-designed approach to energy efficiency can benefit utilities, customers, and society by (1) fostering financially healthy utilities, (2) reducing customers' bills over time, and (3) contributing to positive societal net benefits overall. By establishing and communicating the business case for energy efficiency across utility, customer, and societal perspectives, cost-effective energy efficiency can be better integrated into the energy mix as an important low-cost resource.

Overview

Energy efficiency programs can save resources, lower utility costs, and reduce customer energy bills, but they also can reduce utility sales. Therefore, the effect on utility financial health must be carefully evaluated, and policies might need to be modified to keep utilities financially healthy (return on equity [ROE], earnings per share, debt coverage ratios unaffected) as they pursue efficiency. The extent of the potential economic and environmental benefits from energy efficiency, the impact on a utility's financial results, and the importance of modifying existing policies to support greater investment in these energy efficiency programs depend on a number of market conditions that can vary from one region of the country to another.

To explore the potential benefits from energy efficiency programs and the importance of modifying existing policies, a number of business cases have been developed. These business cases show the impact of energy efficiency investments on the utility's financial health and earnings, customer energy bills, and social resources such as net

Leadership Group Recommendation Applicable to the Business Case for Energy Efficiency

- Broadly communicate the benefits of and opportunities for energy efficiency.

A more detailed list of options specific to the objective of promoting the business case for energy efficiency is provided at the end of this chapter.

Key Findings From the Eight Business Cases Examined

- For both electric and gas utilities, energy efficiency investments consistently lower costs over time for both utilities and customers while providing positive net benefits to society. When enhanced by ratemaking policies to address utility financial barriers to energy efficiency, such as decoupling the utility's revenues from sales volumes, utility financial health can be maintained while comprehensive, cost-effective energy efficiency programs are implemented.
- The costs of energy efficiency and reduced sales volume might initially raise gas or electricity bills due to slightly higher rates from efficiency investment and reduced sales. However, as the efficiency gains help participating customers lower their energy consumption, the decreased energy use offsets higher rates to drive their total energy bills down. In the eight cases examined, average customer bills were reduced by 2 percent to 9 percent over a ten year period, compared to the no-efficiency scenario.
- Investment in cost-effective energy efficiency programs yield a net benefit to society—on the order of hundreds of millions of dollars in net present value (NPV) for the illustrative case studies (small- to medium-sized utilities).

efficiency costs and pollutant emissions. The business cases were developed using an Energy Efficiency Benefits Calculator (Calculator) that facilitates evaluation of the financial impact of energy efficiency on its major stakeholders—utilities, customers, and society. The Calculator allows users to examine efficiency investment scenarios across different types of utilities using transparent input assumptions (see Appendix B for detailed inputs and results).[1] Policies evaluated with the Calculator are discussed in more detail in Chapter 2: Utility Ratemaking & Revenue Requirements and Chapter 3: Energy Resource Planning Processes.

Eight business cases are presented to illustrate the impact of comprehensive energy efficiency programs on utilities, their customers, and society. The eight cases represent a range of utility types under different growth and investment situations. Each case compares the consequences of three scenarios—no energy efficiency programs without a decoupling mechanism, energy efficiency without decoupling, and energy efficiency with decoupling. Energy efficiency spending was assumed to be equal to 2 percent of electricity revenue and 0.5 percent of natural gas revenue across cases, regardless of the decoupling assumption; these assumptions are similar to many of the programs being managed in regions of the country today.[2] In practice, decoupling and shareholder incentives often lead to increased energy efficiency investments by utilities, increasing customer and societal benefits.

Business Cases Evaluated

Cases 1 and 2: Investor-Owned Electric and Natural Gas Utilities

- Case 1: Low-Growth
- Case 2: High-Growth

Cases 3 and 4: Electric Power Plant Deferral

- Case 3: Low-Growth
- Case 4: High-Growth

Cases 5 and 6: Investor-Owned Electric Utility Structure

- Case 5: Vertically Integrated Utility
- Case 6: Restructured Delivery-Only Utility

Cases 7 and 8: Publicly and Cooperatively Owned Electric Utilities

- Case 7: Minimum Debt Coverage Ratio
- Case 8: Minimum Cash Position

Table 4-1 provides a summary of main assumptions and results of the business cases.

Table 4-1 summarizes assumptions about the utility size, energy efficiency program, and each business case. All values shown compare the savings with and without energy efficiency over a 15-year horizon. The present value calculations are computed over 30 years, to account for the lifetime of the energy efficiency investments over 15 years.

1 The Calculator was designed to assess a wide variety of utility types using easily obtainable input data. It was not designed for applications requiring detailed data for specific applications such as rate setting, comparing different types of energy efficiency policies, cost-effectiveness testing, energy efficiency resource planning, and consumer behavior analysis

2 See Chapter 6: Energy Efficiency Program Best Practices for more information on existing programs.

3 Cumulative and NPV business case results are calculated using a 5 percent discount rate over 30 years to include the project life term for energy efficiency investments of 15 years. All values are in nominal dollars with NPV reported in 2007 dollars (year 1 = 2007). Consistent rates are assumed in year 0 and then adjusted by the Calculator for case-specific assumptions. Reductions in utility revenue requirement do not change with decoupling in the Calculator, but might in practice if decoupling motivates the utility to deliver additional energy efficiency. In these cases, societal benefits conservatively equals only the savings from reduced wholesale electricity purchases and capital expenditures minus utility and participant costs of energy efficiency. Energy efficiency program costs given in \$/megawatt-hour (MWh) for electric utilities and \$/million British thermal units (MMBtu) for gas utilities.

Table 4-1. Summary of Main Assumptions and Results for Each Business Case Analyzed[3]

	Case 1: Low Growth Electric Utility	Case 2: Low Growth Electric Utility	Case 3: Low Growth with 2009 Power Plant	Case 4: Low Growth with 2009 Power Plant	Case 5: Vertical Utility	Case 6: Delivery Utility	Case 7: Electric Public/Coop Debt Coverage Ratio	Case 8: Electric Public/Coop No Debt	Case 1: High Growth Gas Utility	Case 2: Low Growth Gas Utility
Utility Size										
Annual Revenue ($MM) - Year 0	$284	$284	$284	$284	$284	$284	$237	$237	$344	$344
Peak Load (MW) or Sales (BcF) - Year 0	600 MW	600 MW	600 MW	600 MW	600 MW	600 MW	600 MW	600 MW	33 BcF	33 BcF
Parameter Tested	Load Growth	Load Growth	Load Growth	Load Growth	Vertical Utility	Delivery Utility	Debt Coverage Ratio	Cash Position	Load Growth	Load Growth
Assumptions That Differ Between Cases										
Load Growth Assumption	1%	5%	1%	5%	2%	2%	2%	2%	0%	2%
Average Rate - Year 1	$0.12/MWh	$0.12/MWh	$0.12/MWh	$0.12/MWh	$0.12/MWh	$0.12/MWh	$0.10/MWh	$0.10/MWh	$1/therm	$1/therm
EE Program	EE Program Results do not change when decoupling is activated									
Cumulative Savings (EE vs No EE case)	8,105 GWh	8,105 GWh	8,105 GWh	8,105 GWh	8,105 GWh	8,105 GWh	6,754 GWh	6,754 GWh	31 BcF	31 BcF
Utility Spending as Percent of Revenue (%)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	0.5%	0.5%
Annual Utility Spending (NPV in $MM)	$70	$70	$70	$70	$70	$70	$58	$58	$21	$21
EE Project Life Term (years)	15	15	15	15	15	15	15	15	15	15
Percent of Growth Saved	142%	21%	142%	21%	66%	66%	55%	55%	410%	18%
Total Cost of EE in Year 0 ($/MWh or $/MMBtu)	$35.00	$35.00	$35.00	$35.00	$35.00	$35.00	$35.00	$35.00	$3.00	$3.00
Utility Cost in Year 0 ($/MWh or $/MMBtu)	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$1.50	$1.50
Customer Cost in Year 0 ($/MWh or $/MMBtu)	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$1.50	$1.50
Business Case Results (NPV in $MM)	Revenue Requirement and Net Societal Savings do not change with decoupling. Business Case results are the difference between the No EE and EE cases.									
Reduction in Revenue Requirement ($MM)	$396	$318	$476	$338	$372	$348	$288	$270	$211	$142
% of Total Revenue Requirement	5.5%	3.0%	6.0%	3.0%	4.1%	4.4%	4.0%	4.3%	3.8%	2.2%
Net Customer Savings - no decoupling ($MM)	$504	$372	$608	$375	$447	$437	$459	$266	$258	$156
% of Total Customer Bills	7.0%	3.5%	7.7%	3.3%	6.4%	5.6%	6.4%	4.2%	4.6%	2.4%
Net Customer Savings - decoupling ($MM)	$344	$266	$424	$286	$320	$296	$245	$226	$158	$90
% of Total Customer Bills	4.8%	2.5%	5.4%	2.5%	4.5%	3.8%	43.4%	3.6%	2.8%	1.4%
Net Societal Savings ($MM)	$289	$258	$332	$269	$282	$271	$225	$225	$143	$119
% of Total Societal Cost	237.5%	211.9%	272.6%	221.0%	6.7%	222.2%	222.2%	222.2%	338.0%	282.6%
Air Emission Savings	Air Emission Savings are the difference between No EE and EE cases and do not change when decoupling is activated									
1000 Tons CO_2	311	311	311	311	311	311	259	259	128	128
Tons NO_x	61	61	61	61	61	61	51	51	107	107

BcF = billion cubic feet; CO_2 = carbon dioxide; EE = energy efficiency; GWh = gigawatt-hour; NO_x = nitrous oxides; $MM = million dollars; MMBtu = million British thermal units; MWh = megawatt-hour; NPV = net present value

While these eight business cases are not comprehensive, they allow some generalizations about the likely financial implications of energy efficiency investments. These generalizations depend upon the three different perspectives analyzed:

- *Utility Perspective*. The financial health of the utility is modestly impacted because the introduction of energy efficiency reduces sales. If energy efficiency is accompanied with mechanisms to protect shareholders—such as a decoupling mechanism to buffer revenues and profits from sales volumes—the utility's financial situation can remain neutral to the efficiency investments.[4] This effect holds true for both public and investor-owned utilities.

- *Customer Perspective*. Access to energy efficiency drives customer bills down over time. Across the eight case studies, energy bills are reduced by 2 percent to 9 percent over a 10 to 15-year period. Even though the efficiency investment and decreased sales drives *rates* slightly higher, this increase is more than offset in average customer bills due to a reduction in energy usage.

- *Societal Perspective*. The monetary benefits from energy efficiency exceed costs and are supplemented by other benefits such as lower air emissions.

Generalizations may also be made about the impact of policies to remove the throughput incentive, such as decoupling mechanisms, across these business cases.[5] These generalizations include:

- *Utility Perspective*. Policies that remove the throughput incentive can provide utilities with financial protection from changes in throughput due to energy efficiency, by smoothing the utility's financial performance while lowering customer bills. Generally, the business case results show that a decoupling mechanism benefits utilities more if the energy savings from efficiency are a greater percent of load growth. Also, because small reductions in throughput have a greater effect on the financial condition of distribution utilities, decoupling generally benefits distribution utilities more than vertically integrated utilities. A utility's actual results will depend on the structure of its efficiency program, as well as the specific decoupling and attrition mechanisms.

- *Customer Perspective*. Decoupling generates more frequent, but smaller, rate adjustments over time because variations in throughput require periodic rate "true-ups." Decoupling leads to modestly higher rates earlier for customers, when efficiency account for a high percent of load growth. In all cases, energy efficiency reduces average customer bills over time, with and without decoupling.

- *Societal Perspective*. The societal benefits of energy efficiency are tied to the amount of energy efficiency implemented. Therefore, to the extent that decoupling encourages investment in energy efficiency, it is a positive from a societal perspective. Decoupling itself does not change the societal benefits of energy efficiency.

While these cases are a good starting point, each utility will have some unique characteristics, such as differences in fuel and other costs, growth rates, regulatory structure, and required capital expenditures. These and other inputs can be customized in the Calculator so users can consider the possible impacts of energy efficiency on their unique situations. The Calculator was developed to aid users in promoting the adoption of energy efficiency programs, and the results are therefore geared for education and outreach purposes.[6]

4 Though not modeled in these business case scenarios, incentive mechanisms can also be used to let shareholders profit from achieving efficiency goals, further protecting shareholders Such incentives can increase the utility and shareholder motivations for increased energy efficiency investment

5 The decoupling mechanism assumed by the Calculator is a "generic" balancing account that adjusts rates annually to account for reduced sales volumes, thereby maintaining revenue at target projections Differences in utility incentives that alternative decoupling mechanisms provide are discussed in Chapter 2: Utility Ratemaking & Revenue Requirements, but are not modeled. The decoupling mechanism does not protect the utility from cost variations.

6 The Calculator was designed to assess a wide variety of utility types using easily obtainable input data. It was not designed for applications requiring detailed data for specific applications such as rate setting, comparing different types of energy efficiency policies, cost effectiveness testing, energy efficiency resource planning, and consumer behavior analysis