



Chapter 6. Utility Planning and Incentive Structures

Public utility commission (PUC) long-term planning policies and utility incentive and rate structures play an important role in determining the attractiveness of investments in energy efficiency and clean distributed generation (DG). In most states, utility profits are reduced if they experience reduced energy sales as a result of aggressive investments in energy efficiency or customer-sited distributed generation. Most utilities can also lose an opportunity for additional revenue when investing in demand-side resources instead of new supply, transmission, and distribution. Rate structures, including exit fees, standby rates, and buyback rates, can create unintended barriers to distributed generation. State PUCs can achieve goals for low-cost, reliable energy markets while also supporting larger state clean energy efforts by removing existing utility disincentives.

This chapter provides an in-depth discussion of three policies that states have successfully used to address disincentives to create effective energy markets. The information presented about each policy is based on the experiences and best practices of states that are implementing the programs, as well as on other sources, including local, regional, and federal agencies and organizations; research foundations and nonprofit organizations; universities; and utilities.

Table 6.1 lists examples of states that have implemented these policies. States can refer to this table for an overview of the policies described in this chapter and to identify other states they may want to contact for additional information about their clean energy policies or programs. The *For More Information* column lists the *Guide to Action* section where each in-depth policy description is located.

Clean Energy Policies

Type of Policy	For More Information
State Planning and Incentive Structures	
Lead by Example	Section 3.1
State and Regional Energy Planning	Section 3.2
Determining the Air Quality Benefits of Clean Energy	Section 3.3
Funding and Incentives	Section 3.4
Energy Efficiency Actions	
Energy Efficiency Portfolio Standards	Section 4.1
Public Benefits Funds for Energy Efficiency	Section 4.2
Building Codes for Energy Efficiency	Section 4.3
State Appliance Efficiency Standards	Section 4.4
Energy Supply Actions	
Renewable Portfolio Standards	Section 5.1
PBFs for State Clean Energy Supply Programs	Section 5.2
Output-Based Environmental Regulations to Support Clean Energy Supply	Section 5.3
Interconnection Standards	Section 5.4
Fostering Green Power Markets	Section 5.5
Utility Planning and Incentive Structures	
Portfolio Management Strategies	Section 6.1
Utility Incentives for Demand-Side Resources	Section 6.2
Emerging Approaches: Removing Unintended Utility Rate Barriers to Distributed Generation	Section 6.3

In addition to these three policies, states are adopting a number of other policies that maximize the benefits of energy efficiency and clean energy

Table 6.1: Utility Planning and Incentive Structures

Policy	Description	State Examples	For More Information
Portfolio Management Strategies	Portfolio management strategies include energy resource planning approaches that place a broad array of supply and demand options on a level playing field when comparing and evaluating them in terms of their ability to meet projected energy demand and manage uncertainty.	CA, CT, IA, MT, NV, OR, PA, VT, Idaho Power, Northwest Power and Conservation Council, PacifiCorp, Puget Sound Energy	Section 6.1
Utility Incentives for Demand-Side Resources	A number of approaches—including decoupling and performance incentives—remove disincentives for utilities to consider energy efficiency and clean distributed generation equally with traditional electricity generation investments when making electricity market resource planning decisions.	AZ, CA, CT, ID, MA, MD, ME, MN, NY, NM, NV, OR, WA,	Section 6.2
Emerging Approaches: Removing Unintended Utility Rate Barriers to Distributed Generation	Electric and natural gas rates, set by Public Utility Commissions, can be designed to support clean DG projects and avoid unintended barriers, while also providing appropriate cost recovery for utility services on which consumers depend.	<i>Exit Fees:</i> IL, MA, CA <i>Standby Rates:</i> CA, NY <i>Gas Rates:</i> NY	Section 6.3

through planning and incentives approaches. These additional policies are addressed in other sections of the *Guide to Action*, as described as follows.

- *State and Regional Planning* activities identify opportunities to incorporate clean energy as a way to meet future load growth (see Section 3.2).
- *Funding and Incentives* describes additional ways states provide funding for clean energy supply through grants, loans, tax incentives, and other funding mechanisms (see Section 3.4).
- *Public Benefits Funds* are pools of resources used by states to invest in energy efficiency and clean energy supply projects and are typically created by levying a fee on customers' electricity bills (see Section 4.2, *PBFs for Energy Efficiency*; and Section 5.2, *PBFs for State Clean Energy Supply Programs*).

6.1 Portfolio Management Strategies

Policy Description and Objective

Summary

Some state public utility commissions (PUCs) require utilities to conduct portfolio management as a way to provide least-cost and stable electric service to customers over the long term. Portfolio management addresses other electric generation and transmission concerns, including reliability, safety, risk management, and environmental issues.

Portfolio management refers to the utility's energy resource planning and procurement strategies. These strategies, required by the state, cover both the generation of electricity and its transmission to customers. A successful portfolio management approach typically includes forecasting customer demand for electricity and resource supply, identifying and assessing a range of resource "portfolio" scenarios, and developing a plan for acquiring the preferred mix of resources.

An ideal portfolio is diversified; it provides many options to allow the utility to adapt to shifting market conditions, including:

- A variety of fuel sources such as coal, natural gas, nuclear power, and clean energy sources. Some states actively promote and sometimes require the use of clean energy sources for some of the electricity supplied to their customers.
- A variety of technologies for the generation and delivery of electricity.
- Programs that encourage customers to adopt energy efficiency measures.
- Financial incentive programs to encourage customers to reduce their consumption during peak demand periods.

Portfolio management refers to energy resource planning that incorporates a variety of energy resources, including supply-side (e.g., traditional and renewable energy sources) and demand-side (e.g., energy efficiency) options. The term "portfolio management" has emerged in recent years to describe resource planning and procurement in states that have restructured their electric industry. However, the approach can also include the more traditional integrated resource planning (IRP) approaches applied to regulated, vertically integrated utilities.

Portfolio management involves deliberately choosing among a variety of electricity products and contracts. The approach emphasizes diversity—diversity of fuels, diversity of technologies, and diversity of power supply contract durations. In its fullest form, energy efficiency and renewable generation are key strategy components.

Objective

States are requiring utilities to use portfolio management strategies to achieve a mix of resources that efficiently and reliably meet consumers' near- and long-term service needs in a manner that is consistent with environmental policy objectives. The most comprehensive portfolio management strategies consider demand- and supply-side resources and include clean energy as an important component of a diversified resource portfolio. Several states also consider rate structure issues and performance-based regulation to place energy efficiency and clean distributed generation (DG) on a level playing field with supply options (see Section 6.2, *Utility Incentives for Demand-Side Resources*).

Portfolio management strategies are used both in states where a regulated utility has an obligation to provide full service to customers and in "retail choice" states where the regulated entity's service might be restricted to distribution and default service.

Benefits

Portfolio management offers benefits through risk management and improved efficiency. Diversification is a key risk management strategy and can take the form of supply contract terms and conditions as well as supply from varied fuels, technologies, and a mix of generation resources. Additionally, diversification can result in a mix of transmission, demand-side resources, energy efficiency, and demand response. With diversification, each resource represents a relatively smaller proportion of the total electricity required to serve customers. This reduces price risks associated with a specific resource type, decreasing the possibility that customers will be exposed to a sudden increase in their electric rates.

Even though many portfolio management strategies are rooted in managing price risks for customers, environmental benefits flow naturally from portfolio management, particularly those strategies that ensure equal consideration of renewable generation and energy efficiency. For example, portfolio management delivers clean air benefits by shifting the focus of procurement from short-term, market-driven, fossil fuel-based prices to long-term, customer costs and customer bills by ensuring the consideration of energy efficiency and renewable generation resources. Portfolio management can also address additional benefits, including increased system reliability and reduced security risks.

Background

In the late 1980s and early 1990s, integrated resource planning (IRP) was common in the electric industry. With vertically integrated electric utilities responsible for generation, transmission, and distribution services for their customers, IRP was a useful tool for developing the most efficient resource portfolio. In 1992, 36 states had IRP requirements in place. After restructuring, the prevalence of ratepayer-funded energy efficiency programs declined significantly as the focus of resource planning shifted to short-term commitments. States either rescinded their IRP regulations or ceased requiring utilities to comply with them, in anticipation that customer choice would result in an optimal resource mix.

When customer choice did not deliver these benefits, some states and utilities began returning to IRP and portfolio management as a tool to ensure a variety of public policy goals, including clean, low-cost, reliable power. Having learned from previous experience, IRP policies today are more effective and vary greatly by state.

Some states are continuing to apply IRP regulations. Other states are requiring that a distribution company or other entity be responsible for acquiring a long-term, diverse resource portfolio to serve customers. In states served by regulated, vertically integrated utilities, portfolio management strategies are implemented through individual utilities' IRPs.

Some retail choice states, served by regulated distribution companies and competitive suppliers, are using portfolio management to stabilize and lower prices for default service consumers. To date, the primary focus of portfolio management in states with retail choice has been the management of costs and risks of supply contracts. Interested states that want to take a more expansive view of portfolio management are beginning to explore ways to incorporate clean energy into portfolio management.

States That Have Adopted Portfolio Management Strategies

Integrated Resource Planning

Several states currently have instituted IRP requirements, including California, Colorado, Hawaii, Idaho, Indiana, Minnesota, Oregon, and Washington. Many electric companies have developed detailed IRPs to guide their resource management and procurement practices in response to various state regulations. They include Avista Corporation, Idaho Power Corporation, PacifiCorp, Portland General Electric (PGE), Georgia Power Company, Duke Power, Xcel Energy, and Puget Sound Energy (PSE).

As vertically integrated facilities, these utilities own their generating assets. They use their IRPs to weigh the benefits of building their own generation plants against procuring energy from other entities. The plans also evaluate how best to balance peak versus

off-peak electric load requirements. In addition, they compare various supply- and demand-side options and contract and financial hedging options. Companies achieve these goals simultaneously by analyzing different scenarios. The IRPs detail fuel and electricity price information, customer demand forecasts, existing plant performance, other plant additions in the region, and legislative decisions.

Retail Choice Portfolio Management

As states have restructured the electric industry, they have struggled with the appropriate pace of transition from regulated full-service supply from integrated utilities to full retail choice in a competitive market. Originally, many states hoped that the majority of customers would select a competitive supplier. Many states also included provisions for default service, which would be procured through the regulated distribution company to supply customers who could not, or would not, find a supplier in the competitive market. These services were expected to provide a declining proportion of retail service.

Because the transition to competitive retail markets has been slower than anticipated, default services have taken on greater prominence as the main supply option for most customers with few competitive options. In fact, in restructured states, the majority of residential and small commercial customers continue to take electricity through their default service provider, despite the option to choose their supplier. This trend is expected to continue into the future, making the provision of default service an important element in meeting customers' service needs.

Consequently, to ensure least-cost and reliable supply for customers, several states have mandated portfolio management approaches for the provision of these noncompetitive services, as described in Table 6.1.1.

Some restructured states have adopted a particular aspect of portfolio management: laddering (or "dollar cost averaging") of generation contracts for default service procurement. This approach can offer greater price stability, supplier diversity, and flexibility to adapt to changing loads than a one-time procurement for the entire default service load.

Table 6.1.1: States That Use Diverse Contract Terms

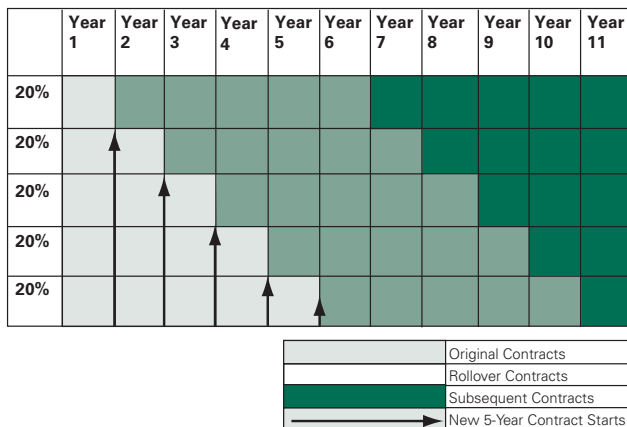
State	Procurement Rules for Default Service
Connecticut	Contracts are procured in overlapping pattern of fixed periods. The contracts must be for terms of not less than 6 months, unless shorter terms are justified.
Delaware	Delaware has proposed an approach similar to that used in New Jersey: a 3-year ladder of contracts.
Illinois	Illinois has proposed a mix of 1-, 3-, and 5-year contracts for its default service electric procurement.
Maryland	Utilities must attempt to obtain 1-, 2-, and 3-year contracts with 50% of load served through 1-year contracts.
New Jersey	There is a single annual auction date. Each year, 1/3 of the load is procured under fix-priced, 3-year contracts.
Washington, D.C.	Recommends that utilities' contract mix include contracts of at least 3 years for no less than 40% of the total load.

Source: Synapse 2005.

The objective of using such a laddered contract approach is that in each year only a fraction of the electric load is exposed to market price uncertainty. Figure 6.1.1 illustrates a basic five-year ladder. Utilities can also manage exposure to market price risk by executing a mix of contracts over short-, mid- and long-term contracts.

Additional tools beyond basic laddering might yield greater price and stability benefits for customers. For example, one enhancement that would promote clean energy would be a dedicated, renewable energy tranche. In other words, a portion of the load can be dedicated specifically to long-term renewable contracts. This would provide not only technology diversification, but also contract length diversification and more stable prices over the long run.

Figure 6.1.1: A Laddered Approach to Default Service Contracts Offers Flexibility and Price Stability



Source: Roschelle and Steinhurst 2004.

Non-State Jurisdictional Entities

While this section focuses on state policies pertaining to portfolio management, portfolio management strategies are a useful planning tool regardless of whether they are required by a state regulatory body or undertaken at the initiative of an individual company, municipal utility, or cooperative. They can be used in both private utilities and public power utilities. The strategies and approaches described in this section are applicable in a wide range of corporate structures and can be adapted to the circumstances of individual companies.

One of the most comprehensive portfolio management efforts takes place in the Pacific Northwest through the Northwest Power and Conservation Council. The Northwest Power and Conservation Council was created by Congress in 1980 as an interstate compact agency for the states of Idaho, Montana, Oregon, and Washington. The region is served by a federal power project (through the Bonneville Power Administration [BPA]), investor owned utilities (IOUs), municipal utilities, and power cooperatives.

The Northwest Power and Conservation Council periodically develops 20-year power plans to ensure an adequate, efficient, economical, and reliable power system and to address the impacts of the region's hydropower system on fish and wildlife. These power plans establish a regional context for the power planning of individual public and investor-owned utilities and provide information on the region's power system. Additionally, the plans offer broadly applicable resource strategies and methods to evaluate uncertainty and risk that can be used in individual companies' planning processes. The Northwest Power and Conservation Council's Fifth Plan is described in *State and Regional Examples*, on page 6-13.

The American Public Power Association (APPA) provides information for public power utilities regarding the inclusion of clean energy in energy portfolios. A 2004 APPA guidebook describes strategies other utilities have used to increase their percentage of renewable energy and provides a step-by-step process for considering renewable resources, especially wind and geothermal, in smaller public power system resource portfolios. Many publicly owned utilities develop IRPs. Examples of these include Seattle City Light, Tacoma Power, the Los Angeles Water and Power District, and the Sacramento Municipal Utility District.

Designing an Effective Portfolio Management Policy

State portfolio management policies, whether for vertically integrated utilities or distribution service providers, create a comprehensive planning and procurement process that levels the playing field for energy efficiency and clean energy supply. The regulated entity must then develop a plan for implementing the policy. This section describes the portfolio management process, including the planning process, participants, funding, timing and duration, and interaction with state practices.

Planning Process

Portfolio management typically involves a multi-step process of forecasting, resource identification, scenario analysis, and resource procurement, as described below.

Forecasting

A utility's first step in portfolio management is to forecast customer demand and resource supply over the planning horizon. Utilities include expected energy efficiency improvements outside of the utility's energy efficiency resources in their load forecasts. By forecasting demand and supply, a utility identifies the timing and magnitude of future resource needs.

Identifying Potential Resources

Next, the utility assesses the wide variety of supply and demand resources available to meet their identified needs. Supply-side resources include traditional sources such as power plants, purchasing from the wholesale spot market, purchasing short-term and long-term forward contracts, and purchasing derivatives to hedge against risk. Supply resources also include clean energy, such as renewable power. Demand-side resources can include energy efficiency programs and demand response. Utilities also assess expanding transmission and distribution facilities, and sometimes consider DG options.

Many states that require IRP establish criteria for evaluating resource options and a process for selecting resources. The criteria can include environmental, economic, reliability, security, and social factors and direct project costs. These factors create an evaluation framework that values the attributes of clean energy as part of the least-cost resource solution.

Recognizing Environmental Costs

Some states, such as California, require consideration of environmental factors as part of their planning process. California requires utilities to consider the cost of future carbon reduction regulations in their long-term planning by requiring a "cost adder" for supplies from fossil fuel plants. This means that for resource comparison purposes, utilities increase the cost of fossil fuel-based supplies to reflect the

financial risk associated with the potential for future environmental regulation. This makes fossil fuel plants less attractive as compared to clean energy. Vermont law requires that utilities prepare a plan for providing energy services at the lowest present value life cycle costs, including environmental and economic costs.

Similarly, several utilities, including PacifiCorp, Idaho Power, PGE, Avista, and Xcel, incorporate an estimate of potential carbon emissions fees into their planning processes. For example, Montana requires utilities to consider environmental factors in portfolio management, but it does not require consideration of "environmental externalities." These "externalities," added to the cost of resources, can be used to incorporate estimates of sensitivity to risk associated with the environmental effects of plant emissions (e.g., acid rain, climate change, and other issues).

Creating the Preferred Resource Mix

After establishing evaluation criteria, states and utilities determine the mix of resources that will best meet the regulators' and companies' objectives. In this step, the state PUC directs regulated utilities to identify a mix of possible resources that meets forecasted requirements and addresses as many planning criteria as possible. For example, regulators and utilities might seek the lowest cost, most reliable options that minimize risk and reflect social, cultural, and environmental goals. During this step, utilities analyze the various scenarios and risks associated with different resource "portfolios."

California requires utilities to prioritize their resource acquisitions by incorporating a prioritized resources list established in the state's Energy Action Plan (EAP). Under this plan, also called the "Loading Order," top priority is given to energy efficiency and demand response, followed by renewable energy, then clean fossil-fueled DG, and finally, clean fossil-fueled central generation. Other states include explicit requirements for clean energy in their portfolio management policies. For example, Iowa and Minnesota require utilities to develop conservation or energy efficiency plans for their customers.

Montana mandates that utilities providing default service must consider demand- and supply-side resources when developing their portfolios.

Many states require utilities to conduct a competitive solicitation or other process to ensure that they evaluate options for meeting resource needs using predefined criteria in a fair manner. Oregon, California, and Montana are examples of states that have these types of competitive solicitation requirements.

Participants

States include a broad range of stakeholders as they develop policies and consider alternative scenarios. These stakeholders include state agencies, utilities, supply-side and demand-side resource providers, and customer representatives. For example, California, Connecticut, Oregon, Pennsylvania, Vermont, and Washington work with all interested parties to develop regulations on IRP or portfolio management for default service providers. Montana requires utilities that use portfolio management for default service to conduct a broad-based advisory committee review; make recommendations on technical, economic, and policy issues; and provide opportunities for public input.

After a plan has been implemented, parties reconvene regularly (sometimes annually or more frequently) to see if their strategy should be adjusted for greater effectiveness in achieving policy and stakeholder objectives. For example, PacifiCorp, a utility that operates in five Western states, invites stakeholders to regularly take part in evaluating and implementing its IRP. The cornerstone of the public input is full-day public meetings, held approximately every six weeks throughout the year-long plan development period. Because of PacifiCorp's large service territory, these meetings are held in two locations and employ telephone and video conferencing technology. PacifiCorp has found that this approach encourages wide participation while minimizing participants' travel burdens and scheduling conflicts. Other companies, such as Idaho Power and

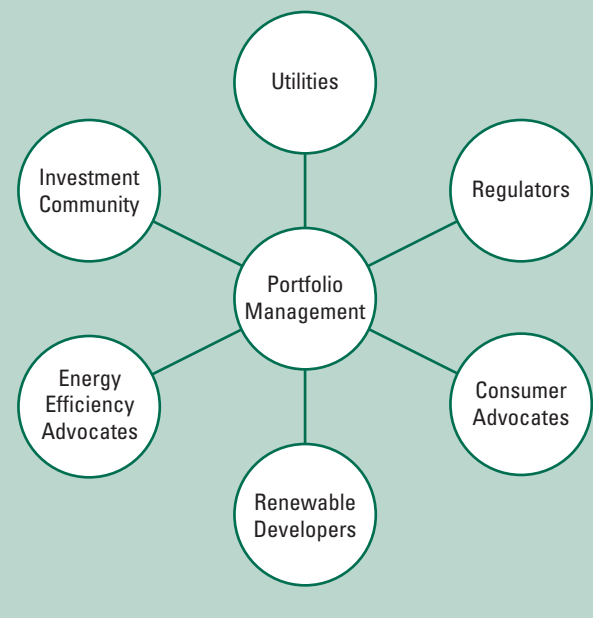
PSE, similarly involve stakeholders and the public in the development of resource plans.

Funding

Vertically integrated utilities or distribution service providers bear the costs of resource planning and procurement, then pass the costs on to retail customers.

Best Practices: Participants

A wide variety of stakeholders can be included in the development of a portfolio management strategy, as shown in this example:



As discussed in Section 6.2, *Utility Incentives for Demand-Side Resources*, different regulatory policies create positive or negative incentives for regulated entities to pursue clean energy. Regulators can establish policies that provide utilities with the appropriate financial incentives to prepare and implement proper resource portfolios. These include incentives to:

- Design and implement cost-effective efficiency programs.

- Develop cost-effective DG options.
- Identify and implement the optimal mix of power plants and purchase contracts.
- Implement risk management techniques.
- Implement, update, and modify the resource plan over time to respond to changing market and industry conditions.

In some instances, cost recovery is not guaranteed, thereby creating an incentive for efficient and effective portfolio design and implementation. For example, in Iowa, the Iowa Utilities Board (IUB) can deny cost recovery when it is not satisfied with a utility's programs and budget.

Timing and Duration

Portfolio management approaches, both IRP and portfolio management for default service, usually incorporate regular planning and solicitation cycles—often ranging from one to five years. Many portfolio approaches include a long-range component (10–20 years) and a more short-term action plan (one to five years). Utilities can improve their portfolio management strategies by scheduling regular reviews and updates (perhaps annually) to accommodate new opportunities and energy use scenarios.

Interaction with State Policies

A variety of state programs and policies can be further leveraged by portfolio management strategies and can provide support to a state's portfolio management planning.

Renewable Portfolio Standard Policies

In the course of electric industry restructuring, many states adopted RPS, which require a given percentage of power from renewable power plants (see Section 5.1, *Renewable Portfolio Standards*). Some states, such as Connecticut and Massachusetts, have determined that default service supply must comply with RPS requirements just as competitive suppliers

must comply. Recent legislation in Nevada allows a company to meet a portion of its RPS with energy efficiency programs.

RPS compliance can be a parallel process, not a constraint, to portfolio management, especially if RPS allows for renewable energy credits (RECs) to be used for procurement of electricity.

Energy Efficiency Programs

State agencies and legislatures can consider how energy efficiency programs will enhance the diversity and resilience of an energy resource portfolio. For vertically integrated utilities, energy efficiency has been a cornerstone of IRP for some time. However, default service suppliers are just now beginning to incorporate energy efficiency into their offerings. With restructuring, energy efficiency programs offer opportunities for lowering system-wide electricity costs and reducing customers' electricity bills. Energy efficiency also offers utilities the opportunity to reduce risk, improve reliability, mitigate peak demands, minimize environmental impacts, and promote economic development.

Even though utilities scaled back their energy efficiency programs during the 1990s, the primary rationale for implementing these programs—to reduce electricity costs and lower customer bills—is just as relevant in today's electricity industry. Consequently, energy efficiency can be a useful component in portfolio management, because it can (1) lower electricity costs and customers' bills, and (2) reduce the amount of generation needed from the market.

Some states have established a public benefits fund (PBF) to ensure that utilities acquire energy efficiency (see Section 4.2, *Public Benefits Funds for Energy Efficiency*). In this case, all distribution companies collect a fixed charge from their customers to provide funding for energy efficiency activities. While PBFs help address some of the concerns that restructuring would reduce energy efficiency funding, they do not capture the full potential of cost-effective energy efficiency.

Consequently, some states ask utilities to use portfolio management to identify and implement additional energy efficiency. PSE in Washington includes energy efficiency based on a comprehensive assessment of technical potential. In its 2003 Integrated Resource Plan, the company identified resource needs that could be met with energy efficiency and followed up with an energy efficiency solicitation. During 2004, the company's electricity efficiency programs avoided about 20 megawatts (MW) of capacity need. For its 2005 Integrated Resource Plan, the company has taken a more targeted approach to energy efficiency, where competitive solicitation will focus on obtaining services for specific customer segments, end uses, or technologies rather than an open-ended solicitation.

In Minnesota, legislative mandates in 1982 and 1991 require utilities to develop conservation improvement programs (CIPs). Utilities include the CIP's energy saving goals in the IRPs, which are filed every two years with the PUC. Often, the utilities are required to complete an energy efficiency market potential study. In reviewing a company's IRP, the PUC sets 15-year demand-side management (DSM) goals for energy and capacity.

Energy Planning

Many states have undertaken comprehensive energy planning processes for the entire state (see Section 3.2, *State and Regional Energy Planning*). Portfolio management strategies are included in some states' energy planning processes and sometimes serve as a mechanism for implementing policy goals identified in the states' energy planning processes. For example, the forecasts developed by utilities in the course of the IRP process have been used to develop an electricity supply-and-demand forecast for the state as a whole. Once a state has established energy policy goals, such as the development of clean energy options, that policy goal can shape the implementation of portfolio management strategies. For example, states such as California that place a priority on certain clean resources require utilities to submit IRPs that are consistent with the overall state policy objectives.

Program Implementation and Evaluation

Portfolio management strategies have been effective when utilities, regulators, and other stakeholders are involved in the implementation process.

Regulators sometimes require utilities to submit portfolio management plans and progress reports at regular intervals. These plans and reports describe in detail

Best Practices: Developing and Adopting a Portfolio Management Policy

The best practices identified below will help states develop effective portfolio management policies. These best practices are based on the experiences of states that use portfolio management:

- Identify state policy goals for portfolio management, including reasonable power cost, stable supply, minimal environmental impacts, resource diversity, customer supply in immature markets, and risk minimization for customers and the utility.
- Identify the entity that will procure electricity resources—options include vertically integrated utilities, distribution utilities, and default service providers.
- Include a diverse representation of stakeholders in the development of the policy and process.
- Establish requirements for forecasting and determining resource needs.
- Determine the appropriate process for acquiring resources and comparing alternative resource options. Ensure that the goals of the process are clear, the process is transparent, the selection criteria are enunciated (including non-price factors), the supply and demand resources are considered, and there are mechanisms for fair procurement.
- Establish clear roles for utility and regulatory authorities (i.e., PUCs) in selecting evaluation criteria, reviewing proposals, and choosing final resources. Some states require an independent monitor to ensure a fair and trusted process.
- Consider finding a balance between the need for transparency and participation and the need for a manageable process.
- Require that all demand and supply resources be considered in meeting identified needs.

the assumptions used, the opportunities assessed, and the decisions made when developing resource portfolios. Regulators then carefully review these plans and either approve them or reject them and recommend changes needed for approval. California requires utilities to submit biennial IRPs and quarterly reports on their plans. Similarly, the IUB requires companies to submit annual reports on their energy efficiency and load management programs.

The Northwest Power and Conservation Council 2005 plan calls for monitoring key indicators that could affect the plan, such as loads and resources, conservation development, cost and availability of wind generation, and climate change science. The results of this monitoring would inform IRPs developed by the utilities in the Northwest Power and Conservation Council region.

Roles and Responsibilities of Implementing Organizations

The regulated entity (e.g., the utility or the default service provider) is responsible for implementing the portfolio management policy. This facility conducts the planning process and the resource solicitation process. It is also responsible for presenting the results of the portfolio management process in a policy forum as required by the state, usually a public proceeding before the state regulatory agency. The regulated entity is also responsible for contractual arrangements associated with any resources procured from a third party. While the regulated entity implements the policy, the state regulatory agency usually plays an oversight role, reviewing planning results and any procurement process.

Administering Body

State utility commissioners oversee utilities' and default service providers' procurement practices in their states. Typically, the commissions solicit comments and input as they develop portfolio management practices from a wide variety of stakeholders, including generation owners, default service providers, competitive suppliers, consumer advocates, renewable developers, environmental advocates, and energy efficiency advocates. The utility regulator may

also play a role in reviewing and approving utilities' planning procedures, selection criteria, and/or their competition solicitation processes. PUCs in different states take different roles in the IRP process. For example, the California Public Utilities Commission (CPUC) has initiated a series of proceedings to design the IRP policy and to review and approve specific utility plans.

Best Practices: Implementing Policy/Programs

The best practices identified below will help utilities implement portfolio management requirements. These best practices are based on the experiences of states that use portfolio management.

- Establish a process that allows all interested parties to provide input and information.
- Prepare a clear, well-documented report that identifies available electricity or gas resources and resources that will be needed in the future.
- Identify all the resources available, both demand and supply, to help the utility meet its resource needs.
- Incorporate risk analyses into the plan to evaluate how different resource options address risks such as future environmental costs and other issues.
- Consider a wide variety of costs in long-term planning, including the societal costs of the environmental effects of power plants and the costs of complying with anticipated regulatory changes.
- Perform computer simulations of what happens when utilities integrate new resource alternatives with existing generation and transmission assets. Include existing demand-side resources.
- Determine an action plan for near-term needs. Identify when the utility may need to procure resources to meet its needs.
- For any competitive solicitation, establish clear requirements and a format for submitting proposals. These may differ for supply and demand resources. Evaluate potential resources according to predetermined criteria.
- Be prepared to consider technology-specific needs in the evaluation criteria; one size fits all may not necessarily be the appropriate approach.
- Identify difficulties with the process that require adjustments in the next forecast and solicitation process.

Evaluation

Portfolio management strategies can be evaluated at a number of levels. Policymakers, utilities, and stakeholders can evaluate the state policy on portfolio management or the utility-specific implementation of, and results from, the portfolio management strategy.

The state's policy on portfolio management can be reviewed in a regulatory proceeding to determine whether the overall policy is achieving stated public policy goals. This is usually spurred by the legislature or PUC.

Once a company has developed a resource plan, some states require a formal evaluation and approval. In other states, an integrated resource plan is filed and accepted without evidentiary review, and is only reviewed for form and completeness. In either case, the expectation is that subsequent utility resource acquisition and investment will conform with the plan unless there is sufficient justification for modification.

Some companies review the success of the plan and make adjustments according to evolving circumstances. For example, PacifiCorp uses an iterative process for updating its plan and ensuring that the plan is consistent with the company's business goals. In this case, the company's energy portfolios are analyzed based on how well they address PacifiCorp's energy supply and demand needs. In addition, the company looks at whether and how much the resources incur risk to utilities, default service providers, generators, and customers.

Utilities use a variety of techniques to quantify the uncertainties associated with a given portfolio and to evaluate the resilience and performance of a particular portfolio under different scenarios and future circumstances.

Evaluating Energy Efficiency Programs

While companies and regulators use a variety of tests to evaluate the cost-effectiveness of energy efficiency programs, many use the Total Resource Cost (TRC) Test as their main method for assessing their energy efficiency program offerings. The TRC Test incorporates the following benefits and costs:

- *Benefits* include avoided supply costs; a reduction in transmission, distribution, generation, and capacity costs; and a reduction in utility bills.
- *Costs* include program administration costs, the incremental costs to acquire and install an efficiency measure regardless of who pays for it, and the increase in supply costs for the periods in which load is increased.

The results of the TRC Test and other cost-effectiveness tests are typically expressed as a ratio of benefits to cost with more favorable programs achieving a benefit-cost ratio greater than or equal to one.⁴¹ Individual measures can then be further screened based on the extent to which benefits exceed costs and other portfolio considerations such as those mentioned above.

Program administrators and their PUCs may require one or more tests to be used for screening the cost-effectiveness of individual measures and programs and whole portfolios. For example, California recently proposed adding the Program Administrator Test as a secondary screening measure to ensure that utilities do not provide excessive financial incentives to program participants (i.e., incentives in excess of incremental measure costs). Some of the most common tests include:

- The *Participant Test*, which takes into account benefits and costs from a participant's perspective.
- The *Rate Impact Measure (RIM) Test*, which takes into account what happens to a customer's bills or

⁴¹ While utilities and PUCs most often express program performance in terms of benefit-cost ratios, it is also helpful to express program costs and benefits in terms of \$/kilowatt-hour (kWh). Consumers and legislators can easily relate this metric to the cost of energy in their own area, while utilities and regulators can compare this value to the cost of other resources such as new generation. When expressed this way, the annual levelized TRC (\$/kWh) captures the net program and customer costs divided by the projected lifetime savings of the measure or program. Demand-side resource costs can also be calculated in \$/kilowatt (kW) to illustrate the value during periods of peak demand.

rates because of changes in revenues and operating costs caused by a program.

- The *Program Administrator Test*, which takes into account the benefits and costs from the program administrator's perspective.
- The *TRC Test*, which takes into account the combined benefits and costs from both the utility's and program participants' perspectives.
- The *Societal Test*, which is similar to the TRC Test, but includes the effects of other societal benefits and costs such as environmental impacts, water savings, and national security.

More information on the typical costs and benefits included in these tests can be found in the *Information Resources* section on page 6–20. States that choose to apply only one test are moving away from the RIM Test because it does not account for the interactive effect of reduced energy demand from efficiency investments on longer-term rates and customer bills. Iowa calls for using several tests in evaluating the cost-effectiveness of utilities' energy efficiency plans. In addition, the IUB conducts periodic regulatory proceedings to review utilities' proposed energy efficiency plans and how they are implemented.

In addition, one important consideration when evaluating energy efficiency and other demand-side resources in comparison with supply-side resources is recognizing the effect of a particular program or investment on the utility's demand curve. An energy efficiency program or other demand-side measure that reduces demand during peak pricing times will provide greater financial benefits than one that reduces demand in low-cost periods. Thus, a simple average of costs and savings across many hours may underestimate the value of a demand-side investment.

Best Practices: Evaluating Policy/Programs

The best practices identified below will help utilities evaluate portfolio management strategies. These best practices are based on the experiences of states that use portfolio management.

- Provide a state procedure for feedback about the policy and how it was implemented. This could include a periodic policy review, a review of written comments, or a review of comments provided within the context of the periodic portfolio management submissions.
- Establish a utility-based procedure for evaluating and obtaining feedback on how the policy was implemented. This could be a regular stakeholder process or other mechanism.
- Evaluate the outcome of each procurement cycle. Consider the appropriateness of the evaluation criteria, how easy it was to participate in the procurement process, perceptions of fairness, and whether the utility was successful in meeting its goals.
- Evaluate the cost-effectiveness of the energy efficiency resources procured as part of the portfolio management strategy. Use a variety of tests, including Societal Cost Tests and TRC Tests.

State and Regional Examples

Oregon

Investor-owned gas and electric utilities file individual least-cost plans or IRPs with the PUC every two years. The plans, required since 1989, cover a 20-year period. The primary goal is to acquire resources at the least cost to the utility and ratepayers in a manner consistent with the public interest. These plans are expected to provide a reasonable balance between least cost and risk. By filing these plans, the utilities hope that in future proceedings the PUC will not reject, and prevent utilities from recouping, some of the costs associated with resource acquisition.

One of the factors that Oregon utilities must consider is the uncertainty associated with certain choices. They consider risk factors such as price volatility, weather, and the costs of current and potential federal

regulations, including regulations that address carbon dioxide (CO₂) emission standards. Recently, the utilities have considered nonquantifiable issues that affect planning. These issues include potential changes in market structure, the establishment of RPS, changes in transmission operation and control, and the effect of PacifiCorp's multi-state process on regulation and cost-recovery. Environmental externalities (i.e., the environmental costs associated with different choices) are considered if they are quantifiable as actual or potential costs.

The state imposes different energy efficiency requirements for different utilities. Idaho Power is required to include energy efficiency. PacifiCorp and PGE are no longer required to evaluate energy efficiency as a resource in Oregon, but must include its impact on load forecasts.

In its 2004 integrated resource plan, PGE states that its recommended resource strategies include strong commitments to upgrading existing PGE power plants, encouraging energy efficiency measures, and acquiring newly developed renewable energy. As a result, approximately 50% of PGE's forecasted load growth between 2004 and 2007 is expected to come from sustainable measures instead of new resources that depend on additional fossil fuels (PGE 2004).

Web site:

http://www.portlandgeneral.com/about_pge/news/irp_opucAcknowledgement.asp?bhcp=1

California

In the beginning of 2003, CPUC ordered the three California utilities—San Diego Gas & Electric (SDG&E), Pacific Gas & Electric (PG&E), and Southern California Edison (SCE)—to resume the role of planning for and buying electricity to meet customer needs. This order followed a two-year period of testing customer choice in retail markets. In Decision 04-01-050, CPUC adopted the long-term regulatory framework under which utilities would plan for and procure energy resources and demand-side investments.

CPUC directed the utilities to prioritize their resource procurements and to follow the priorities, or "loading

order," established in the state's EAP. The EAP identifies certain demand-side resources as preferred because California believes that they work toward optimizing energy conservation and resource efficiency while reducing per capita demand. The EAP also identifies certain preferred supply-side resources. The EAP established the following priority list:

1. Energy efficiency and demand response.
2. Renewable energy (including renewable DG).
3. Clean fossil-fueled DG and clean fossil-fueled central-station generation.

CPUC requires each utility to submit a 10-year procurement plan biennially, detailing its demand forecasts and showing how it plans to meet that demand. The plans must demonstrate that the utility has adequate, reliable supplies and complies with CPUC goals for efficiency and renewable energy. Utilities must file plans that include three scenarios—low load, medium load, and high load. To date, CPUC has approved long-term procurement plans for PG&E, SCE, and SDG&E.

The long-term procurement plan guides each utility's procurement activities. When the utility anticipates needing fossil fuel sources, it must initiate a competitive process designed to ensure that it compares renewable and fossil fuel energy sources. CPUC has directed the utilities to include the costs of CO₂ emissions in their long-term procurement plans and resource evaluation. Utilities must file monthly risk assessments and quarterly reports on the implementation of their plans.

Based on its first comprehensive review of the implementation of the loading order, California Energy Commission (CEC) staff found different success rates for different resources. For example, the state and its utilities are currently ahead of their goals for energy efficiency, but are having a harder time meeting their goals for demand response and renewables. The state continues to work on reducing barriers to DG and to take steps to meet the goals of the loading order policy (CEC 2005).

SCE's request to meet an anticipated energy shortfall during Summer 2005 with an additional \$38 million in efficiency programs demonstrates that the utility is following the EAP's priorities.

Web site:

http://www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/43224.doc

Iowa

Since 1990, the IUB has required Iowa's four investor-owned gas and electric utilities to develop and implement energy efficiency plans that provide opportunities for all customers to reduce electricity and natural gas demand, thereby reducing their bills. Although not part of a traditional IRP process, Iowa's program illustrates how well-designed portfolio management strategies support energy efficiency.

The IUB developed administrative rules for investor-owned utilities based on legislation enacted in 1990 and 1996. The state legislature played a key role in enacting this legislation. It initially requested direction from the IUB to help shape legislation and then through the legislation directed the IUB to establish energy efficiency and load management requirements.

The IUB and the Iowa Department of Natural Resources (DNR) develop capacity and energy savings performance standards for each utility, and each utility must propose a plan and budget for achieving those standards. In developing their plans, the utilities must perform studies that look at the potential of energy efficiency. The legislature directed the board to use several cost-effectiveness tests (i.e., a Societal Test, utility cost test, ratepayer impact test, and Participant Test) in evaluating the overall cost-effectiveness of plans. Each test evaluates the costs and benefits of the program from the perspective of a particular entity. The Societal Test takes into account the environmental effects of resource choices, requiring utilities to compare options by adding 10% to the cost of fossil fuel generation to account for its environmental effects.

In 2001, the IUB requested that each utility provide new energy efficiency plans. As a result, utility energy efficiency spending has increased to above the peak spending levels reached in the early 1990s, an amount that is equivalent to 2% of electric utility revenues and 1.5% of gas utility revenues. Iowa's electric and gas utilities are investing \$80 million annually in energy efficiency and load management programs. These programs are saving 1,000 MW of electrical capacity per year (15% of summer peak demand) and more than 1 million megawatt-hours (MWh) per year. The plans, approved in 2003, are estimated to result in a net savings of \$650 billion over five years (Iowa Department of Natural Resources 2004).

The IUB's energy efficiency planning rules include the following requirements:

- Utilities assess the potential for energy efficiency in each sector and submit an energy efficiency plan that identifies economically achievable programs and describes how the savings will be achieved.
- The IUB conducts case proceedings to review the plans. The proceedings involve a range of stakeholders, including the Office of Consumer Advocate, large industrial customers and environmental groups, and the Iowa DNR, which serves as the state energy office.
- The IUB establishes annual performance goals and budgets for each utility's DSM programs and reviews each utility's energy efficiency plan and budget.

In conjunction with utilities and stakeholders, the IUB developed an automatic cost recovery adjustment mechanism that allows utilities to recover the costs of DSM and load management programs. The IUB conducts a regulatory proceeding to evaluate the reasonableness of plan implementation and the budget. The IUB can deny cost recovery if not satisfied with the utility's implementation and expenditures.

The energy efficiency plans are incorporated into utility load forecasts, and utilities are required to estimate how energy efficiency helps them avoid acquiring new capacity or new resources.

Web site:

<http://www.state.ia.us/dnr/energy/MAIN/PUBS/CEP/index.html>

Vermont

Vermont's State Energy Policy places a strong emphasis on efficient resource use and environmentally sound practices in the provision of adequate, reliable, secure, and sustainable energy service. Legislation requires that each regulated electric and gas company prepare and implement a least-cost integrated resource plan for providing service to its Vermont customers. Under the law pertaining to IRP (30 V.S.A. § 218c. Least Cost Integrated Planning), utilities are required to prepare a plan for providing energy service at the lowest present value life cycle cost, including environmental and economic costs.

The state also prepares a statewide energy plan. The 2005 Vermont Electric Plan, the first update since 1994, contains detailed requirements for electric utilities' integrated resource plans. It also provides a decision framework for addressing uncertainties and multiple contingencies in energy resource selection. These requirements are intended to guide the utilities' planning processes to provide electric service at the lowest present value life cycle cost, including environmental and economic costs. The integrated resource plans should include a combination of supply and demand resources as well as transmission and distribution investments. The process outlined in the Electric Plan is also intended to facilitate information exchange among utilities, regulatory agencies, and the public.

Web site:

<http://publicservice.vermont.gov/divisions/planning.html>

Northwest Power and Conservation Council

The Northwest Power and Conservation Council was created by Congress in 1980 through the Pacific Northwest Electric Power Planning and Conservation Act. The Act requires The Northwest Power and Conservation Council to develop a 20-year power plan to assure the region of an adequate, efficient, economical, and reliable power system. The plan is updated every five years.

The Fifth Northwest Electric Power and Conservation Plan, issued in May 2005, is the most recent plan. The purpose of the plan is to develop plans and policies that enable the region to manage uncertainties that affect the power system and to mitigate risks associated with those uncertainties. The Fifth Plan contains recommended action items for the next five years as well as recommendations beyond five years to prepare the region for possible future scenarios.

The plan includes clean energy options as the primary options to reduce costs and mitigate risks. Clean energy options include energy conservation and efficiency (targeted at 700 MW between 2005 and 2009), demand response (targeted at 500 MW between 2005 and 2009), and wind (targeted at 1,100 MW between 2005 and 2014) from system benefits charges (SBCs) and utility integrated resource plans. To prepare for potential new resources in the future, the plan includes steps to secure sites and permits for expansion of wind resources and develop possible coal gasification facilities, conventional coal resources, and natural gas facilities. The plan also calls for monitoring key indicators that could affect the plan (such as loads and resources, conservation development, cost and availability of wind generation, and climate change science).

Web site:

<http://www.nwcouncil.org/energy/powerplan/plan/Default.htm>

PacifiCorp

PacifiCorp prepares an integrated resource plan for providing electricity to 1.6 million Pacific Power and Utah Power customers throughout Oregon, Washington, Idaho, Wyoming, California, and Utah. The company states that the integrated resource plan is not only a regulatory requirement but is also the primary driver in the company's business planning and resource procurement process.

The 2004 integrated resource plan determined that the most robust resource strategy relies on a diverse portfolio of resources that includes renewable energy, DSM, and natural gas and coal-fired generating resources. The plan identified a need for 2,700 MW of capacity by 2014, and emphasized the company's continuing intention of procuring 1,400 MW of wind capacity and demand-side resources (including energy efficiency). PacifiCorp is currently planning for the 2006 IRP cycle.

The integrated resource plan was developed with public involvement from customer interest groups, regulatory staff, regulators, and other stakeholders. It simulates the integration of new resource alternatives with the company's existing assets and compares their economic and operational performance. The method also accounts for future uncertainties by testing resource alternatives against measurable future risks. The integrated resource plan also looks at possible paradigm shifts in the industry; for example, it accounts for the uncertainty associated with future carbon regulations by increasing the cost of fossil fuel suppliers (for the purpose of comparing resources) by \$8 per ton of CO₂ emitted by fossil fuel plants. The result is a flexible resource strategy centered on the least-cost, risk-weighted mix of resource options.

Web site:

<http://www.pacificorp.com/Navigation/Navigation23807.html>

Idaho Power

The Idaho PUC requires electric utilities to file an integrated resource plan every two years. The plan details the utility's 10-year plan for providing electricity to retail customers in Idaho and Oregon. In

preparing its integrated resource plan for 2004, Idaho Power worked with an Integrated Resource Plan Advisory Council comprising PUC representatives, the Governor's office, state legislators, members of the environmental community, major industrial customers, irrigation representatives, and others. The 2004 integrated resource plan has two primary goals: (1) to identify resources to provide a reliable power supply for the 10-year planning period, and (2) to ensure that the resource portfolio balances cost, risk, and environmental impact. Two secondary goals of the integrated resource plan are to consider supply and demand resources in a balanced fashion and to provide meaningful public input in development of the integrated resource plan.

In developing its plan, Idaho Power analyzed 12 potential resource portfolios, five of which were selected for additional risk analysis. Based on the risk analysis, the preferred portfolio was a diversified one that included nearly equal amounts of renewable generation and conventional thermal generation. The preferred portfolio presented resource acquisition targets for resources including demand response, energy efficiency, wind, geothermal, combined heat and power (CHP), natural gas, and conventional coal, increasing the capacity of the system almost 940 MW over the planning period.

As a result of the 2004 integrated resource plan, Idaho Power intends to issue several requests for proposals (RFPs) before the next integrated resource plan for resources including wind, geothermal, and peaking combustion turbines. The company will also undertake activities relative to demand-side measures and energy efficiency.

Idaho Power has also designed a risk management policy that addresses the short-term resource decisions required in response to changes in load, resources, weather, and market conditions. The risk management policy typically covers an 18-month period and is intended to supplement the long-term IRP process.

Web site:

http://www.idahopower.com/pdfs/energycenter/irp/2004_IRP_final.pdf

Puget Sound Energy

PSE prepares a Least Cost Plan every two years in response to state regulatory requirements. The plan details how the company plans to provide electricity to retail customers in 11 counties in Washington. The company held numerous formal and informal meetings, providing opportunity for public input to the plan.

PSE's 2005 Least Cost Plan identifies plans for acquiring energy efficiency and renewable resources in the near- and long-term, as well as some conventional fossil generation in the long-term. In developing the plan, PSE used scenarios to evaluate risks and portfolio performance associated with certain potential futures.

Web site:

<https://www.pse.com/about/supply/resourceplanning.html>

Clean Energy Requirements in Retail Choice States

Connecticut

Connecticut is an example of a retail choice state with a clear, multifaceted clean energy approach. The state requires all generators that provide transitional offer service (Connecticut's standard offer service) to customers to comply with the state's RPS. In addition to the RPS, Connecticut requires its transitional offer service providers to sign contracts for renewable energy totaling 100 MW. Separate from the RPS requirements, Connecticut offers its transitional service customers the option of choosing from one of two clean energy programs. Under either program, customers can pay a premium and purchase either 50% or 100% of their resources through clean energy. Finally, competitive generators that serve Connecticut customers outside of the transitional offer service must also comply with the state's RPS.

Web site:

<http://www.ctcleanenergy.com>

Pennsylvania

Pennsylvania has taken a different approach to increasing use of clean energy. The state created four

funds as a result of restructuring plans. These funds are designed to promote the development of sustainable and renewable energy programs and clean-air technologies on both a regional and statewide basis. The funds have provided more than \$20 million in loans and \$1.8 million in grants to more than 100 projects. In addition, 20% of standard offer customers are assigned to suppliers that are required to use at least 5% renewable generation.

Web site:

http://www.puc.state.pa.us/utilitychoice/electricity/green_clean.aspx

Montana

Montana established electric least-cost planning rules and policy guidelines that apply to default supply utilities for long-term electric supply resource planning and procurement. Under the "traditional" planning process, the affected utility is required to submit an integrated resource plan every two years. The state also has a "restructured" planning process for one distribution company, where the utility must file a portfolio action plan every year. In both the traditional and restructured processes, the utility must file a long-range plan that includes demand-side resources and supply-side resources. However, the traditional plan must reflect the "least societal cost" and include estimates of the environmental costs of certain options. The restructured plan does not include these factors.

The guidelines for default service state that the objective of the planning process is to assemble and maintain a balanced, environmentally responsible portfolio of power supply and demand-management resources. Both planning processes require utilities to consider the costs of complying with existing and potential environmental regulations.

Nevada

Nevada's 1997 restructuring legislation established an RPS requiring utilities to obtain a minimum percentage of the total electricity they sell from renewable energy resources. The RPS percentages were increased in 2001 and again in 2005. The 2005 revision contained in Assembly Bill 03 (A.B.3) not only increased the required

percentage, but also allowed utilities to meet the standard through energy savings from efficiency measures and renewable energy generation (or credits). Energy efficiency can be used to meet up to one-quarter of the standard in a given year. The 2005 legislation sets new requirements for the total amount of electricity that utilities sell from renewable energy resources at 6% in 2005, rising to 20% in 2015. The PUC must write regulations to implement the legislation.

Web site:

http://leg.state.nv.us/22ndSpecial/bills/AB/AB3_EN.pdf

On the Horizon

Clean energy requirements for default service providers are a relatively new concept that states are exploring. For example, in Illinois, the governor organized a sustainable energy plan initiative with the goal of developing RPS, demand response, and energy efficiency programs. The initiative includes input from utilities, consumer groups, large industrial customers, government agencies, and other industry participants. The Illinois Commerce Commission gathered this input to develop an overall clean energy implementation plan for the state, including voluntary renewable and energy efficiency portfolio standards for public utilities and alternative electricity providers. States are likely to continue to expand these approaches as they seek to ensure that customers are served with portfolios that minimize risks, provide stable prices, and reduce long-term costs. States that are interested in expanding the use of portfolio management in resource procurement may wish to pursue policy approaches that incorporate renewables and energy efficiency into energy service supply in restructured states.

What States Can Do

Many states have found that portfolio management strategies offer a useful and effective tool for implementing their clean energy policy goals. These strategies emphasize the development of a portfolio of resources that are resilient under a wide variety of possible future scenarios and that achieve a wide variety of benefits. States can tailor their portfolio

management strategies to meet their specific clean energy objectives.

Action Steps for States

States that already have a portfolio management policy or program can:

- Link their portfolio management policy to other state policies, such as RPS, energy efficiency, and energy planning policies.
- Review the portfolio management policy regularly and adjust the portfolio as appropriate.
- Assess transmission policies and how they influence generation. Decisions regarding the maintenance or enhancement of transmission and distribution (T&D) facilities will have important consequences for the development of generation and efficiency resources and vice versa. Portfolio managers can consider not only the generation resources that are available with the existing transmission system, but also those that could be tapped via new or upgraded transmission. Conversely, portfolio managers can also consider whether costly T&D upgrades and enhancements can be deferred or avoided. This involves considering the strategic placement of power plants, energy efficiency investments, or DG technologies.

States that do not have a portfolio management policy or program can:

- Educate stakeholders about the benefits of portfolio management, including more stable prices, risk mitigation, lower long-term costs, and a cleaner environment.
- Review other state practices and current utility portfolio management practices.
- Develop a comprehensive policy with clear provisions for program review and modification.

When modifying or adopting portfolio management requirements, states are moving towards policies and programs that strive to minimize total revenue requirements (i.e., total bills paid by customers) rather than electricity rates.

Information Resources

Information About States

State	Title/Description	URL Address
California	Decision 0412048—opinion adopting PG&E, SCE, and SDG&E's long-term procurement plans.	http://www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/43224.doc Other decisions at: http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/43479.htm
	CPUC interim decision on administrative structure for energy efficiency program delivery, designating IOUs for the lead role in program choice and portfolio management.	http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/43628.htm
Connecticut	An example of a state's comprehensive approach to clean energy.	http://www.ctcleanenergy.com
Illinois	Sustainable energy plan initiative to develop an RPS, demand response, and energy efficiency.	http://www.icc.illinois.gov/en/ecenergy.aspx
Iowa	2004 Energy Plan Update.	http://www.state.ia.us/dnr/energy/MAIN/PUBS/CEP/index.html
	2005 Iowa Code: energy efficiency program requirements at Chapter 476.6 (14), and Chapter 467.6(16)–(18).	http://www.legis.state.ia.us/IowaLaw.html
Maine	Another example of how a restructured state thinks about clean energy.	http://www.maine.gov/mpuc/consumer/industry/electricity/index.html
Nevada	A.B.3, June 2005, increasing the RPS and allowing up to one-quarter of the required percentage to be met through energy efficiency measures.	http://leg.state.nv.us/22ndSpecial/bills/AB/AB3_EN.pdf
New Jersey	A detailed description of New Jersey's auction approach to default service.	http://www.bgs-auction.com
Oregon	A brief description of Portland General Electric's 2002 Integrated Resource Plan.	http://www.portlandgeneral.com/about_pge/news/irp_opucAcknowledgement.asp?bhcp=1
Pennsylvania	Information about how the PUC is helping to promote and encourage renewable energy development in Pennsylvania, and a link to the Office of Consumer Advocate's Web site where consumers can find out more information about choosing a "green supplier." Consumers also can find information about air pollution from power plants, fuel sources, and RPS.	http://www.puc.state.pa.us/utilitychoice/electricity/green_clean.aspx
Vermont	Vermont Department of Public Service, 2005 Vermont Electric Plan.	http://publicservice.vermont.gov/divisions/planning.html

State	Title/Description	URL Address
Washington	2005 Biennial Energy Report discusses IRP in the Pacific Northwest.	http://www.cted.wa.gov/_CTED/documents/ID_1872_Publications.pdf
Northwest	Northwest Power and Conservation Council issued its Fifth Northwest Electric Power and Conservation Plan in May 2005. The purpose of the plan is to develop plans and policies that enable the region to manage uncertainties that affect the power system and to mitigate risks associated with those uncertainties.	http://www.nwcouncil.org/energy/powerplan/plan/Default.htm
All States	The Regulatory Assistance Project (RAP) has a survey of some states' IRP practices and discussions of portfolio management that can be found in their subject menu.	http://www.raonline.org

Information About Companies

Title/Description	URL Address
Idaho Power Corporation's IRP	http://www.idahopower.com/energycenter/2004irp.htm
PacifiCorp's IRP	http://www.pacificorp.com/Navigation/Navigation23807.html
PSE's IRP	http://www.pse.com/about/supply/resourceplanning.html

Articles and Reports About Portfolio Management Policy and Specific Programs

Title/Description	URL Address
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American Public Power Association (APPA) 2004. Guidebook to Expanding the Role of Renewables in a Power Supply Portfolio. Prepared by Altera Energy, Inc. September.	http://www.appanet.org/store/ProductDetail.cfm?ItemNumber=11356
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Illinois Commerce Commission Resolution on Governor's Sustainable Energy Plan (05-0437). 2005. July 19.	http://eweb.icc.state.il.us/e-docket/reports/view_file.asp?intIdFile=148072&strC=bd
Illinois Sustainable Energy Initiative ICC Staff Report. 2005. July 7.	http://www.icc.illinois.gov/docs/en/050713ecEnergyRpt.pdf
Joint Statement of Natural Resources Defense Council (NRDC) and Edison Electric Institute on portfolio management.	http://naruc.org/associations/1773/files/eei_nrdc.pdf
Northwest Energy Coalition Report. 2004. Utility Resource Planning Back In Style. 22(5):4-5. June.	http://www.nwenergy.org//publications/report/03_jun/rp_0306_4.html
PSE. 2005. Least Cost Plan. April.	http://www.pse.com/about/supply/resourceplanning.html
RAP. 2005. Clean Energy Policies for Electric and Gas Utility Regulators. January.	http://www.raonline.org/Pubs/IssueLtr/RAPjan2005.pdf
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Iowa DNR. 2004. Iowa Energy Plan Update: A Progress Report.	http://www.iowadnr.com/energy/info/files/04plan.pdf
Portland General Electric. 2004. Newsroom. PGE's power supply plans receive acknowledgement from regulators.	http://www.portlandgeneral.com/about_pge/news/irp_opucAcknowledgement.asp?bhcp=1
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Texas PUC. 2005. Report to the 79th Texas Legislature. Scope of Competition in Electric Markets in Texas. January.	http://www.puc.state.tx.us/electric/reports/scope/2005/2005scope_elec.pdf

6.2 Utility Incentives for Demand-Side Resources

Policy Description and Objective

Summary

Regulators in leading states are reworking traditional ratemaking structures to better align utilities' investment incentives and related decisions with state interest in providing affordable and reliable energy supplies with low environmental impacts. Financial incentive structures for utilities can help align company profit goals with the delivery of cost-effective demand-side resources such as energy efficiency and clean DG. Traditional regulatory approaches link a utility's financial health to the volume of electricity or gas sold via the ratemaking structure, thus providing a disincentive to investment in cost-effective demand-side resources that reduce sales. The effect of this linkage is exacerbated in the case of distribution-only utilities, since the revenue impact of electricity sales reduction is disproportionately larger for utilities without generation resources. Aligning utility aims by decoupling profits from sales volumes, ensuring program cost recovery, and providing shareholder performance incentives 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 more reliable energy system.

Objective

Financial incentive structures for utilities can be designed to encourage utilities to actively promote implementation of energy efficiency and clean DG when it is cost-effective to do so. This includes first minimizing utilities' financial disincentives to deliver energy efficiency and DG resources and then instituting complementary incentive structures to promote and establish high-performing energy efficiency and DG resources. These utility disincentives can be reduced through the elimination or minimization of "throughput disincentives" embedded in traditional ratemaking mechanisms. Complementary incentive

While some utilities manage aggressive energy efficiency and clean distributed generation (DG) programs as a strategy to diversify their portfolio, lower costs, and meet customer demand, many still face important financial disincentives to implementing these programs. Regulators can establish or reinforce several policies to help address these disincentives, including decoupling of profits from sales volumes, ensuring program cost recovery, and defining shareholder performance incentives.

structure objectives include ensuring recovery of costs for effective, economic energy efficiency and DG programs and rewarding utility management and shareholders for well-run and well-performing energy efficiency and DG installation and promotion.

Benefits

States have found that a well-designed framework for utility incentives helps utilities increase the use of energy efficiency and clean DG, which reduces the demand for central station electric generation, lowers consumption and demand for natural gas, reduces air pollution, and decreases the load on transmission and distribution systems.

Such a utility incentive structure can also lead to an increase in the reliability of electric power and gas delivery systems resulting from the increased use of energy efficiency and DG resources. Delivering cost-effective energy efficiency or DG resources reduces a utility's need to build expensive new central station power plants or transmission lines—or expand existing ones—and thus maximizes the value of a utility's existing gas or electric capacity. Energy efficiency and clean DG programs can also lower overall production costs and average prices.

Background on Utility Incentive Structures

A large majority of electric utility costs, including costs for non-jurisdictional energy service companies

such as municipalities and cooperatives, are fixed to pay for capital-intensive equipment such as wires, poles, transformers, and generators. Utilities recover most of these fixed costs through volumetric-based rates, which change with each major "rate case," the traditional and dominant form of state-level utility ratemaking. Between rate cases, however, utilities have an implicit financial incentive to see increased regulated retail sales of electricity (relative to forecast levels, which set "base" rates) and to maximize the "throughput" of electricity across their wires. This ensures recovery of fixed costs and maximizes allowable earnings; however, it also creates a disincentive to investing in energy efficiency during the time between rate cases. Recovery of variable costs in some states is assured through regular (usually quarterly) adjustments (e.g., for fuel) and thus does not impose analogous disincentives. Utilities with regular adjustments for variable fuel expenses have an even greater disincentive for energy efficiency than utilities that do not.

With traditional ratemaking, there are few or no mechanisms to prevent "over-recovery" of these fixed 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). This dynamic creates an automatic disincentive for utilities to promote energy efficiency or DG, because those actions—even if clearly established and agreed-upon as a less expensive means to meet customer needs—will reduce the amount of money the utility can recover toward payment for fixed costs.

If ratemaking explicitly accounted for this effect, for example, by allowing more frequent true-ups to rates to reflect actual sales and actual fixed cost revenue requirements, then this disincentive would be removed or minimized and energy efficiency options would then be able to compete on a level playing field with alternative supply options. A simplified illustration of this decoupling rate effect is shown in Table 6.2.1. Separate, supplemental shareholder

Table 6.2.1: Simplified Illustration of Decoupling Rate Effect

Rates and fixed cost recovery during initial period:			
	Sales At Forecast	Sales Below Forecast	Sales Above Forecast
Sales Forecast	100 kWh		
Fixed Cost ^a	\$6.00		
Variable Cost ^b	\$0.04 per kWh		
Total Variable Cost	\$4.00	\$3.80	\$4.20
Total Costs [Fixed + Variable]	\$10.00	\$9.80	\$10.20
Authorized Rate [Costs Sales Forecast]	\$0.100 per kWh		
Actual Sales	100 kWh	95 kWh	105 kWh
Actual Revenues	\$10.00	\$9.50	\$10.50
Fixed Cost Recovery [Revenue - Cost]	Even \$0.00	Under (\$0.30)	Over \$0.30
Rates in next period after decoupling true up:			
	Sales At Forecast	Sales Below Forecast	Sales Above Forecast
Sales Forecast ^c	100 kWh		
Total Costs ^c	\$10.00		
Revenue Requirement [Total Costs - Fixed Cost Recovery]	\$10.00	\$10.30	\$9.70
New Authorized Rate [Revenue Requirement Sales Forecast]	\$0.100 per kWh	\$0.103 per kWh	\$0.097 per kWh

^a Fixed costs include return on rate base.
^b Variable costs include operating costs of power plants.
^c Assumes values from initial period for illustrative purposes.

Sources: PG&E 2003, Bachrach et al. 2004.

incentive mechanisms, such as performance-based return on equity (ROE) guarantees, could then operate more effectively in the absence of the disincentive that the standard ratemaking otherwise imposes on utilities. Frequent true-ups and shareholder incentives are more desirable relative to high fixed rates since fixed rates greatly diminish customers' incentives for energy efficiency.

States with Utility Incentive Programs for Demand-Side Resources

States have found three steps for leveling the playing field for demand-side resources through improved utility rate design:

- *Remove Disincentives.* Some states have removed structures that discourage implementation of energy efficiency and clean DG through “decoupling” efforts that divorce profits from sales volumes.
- *Recover Costs.* Some states have given utilities a reasonable opportunity to recover the costs of energy efficiency and clean DG programs (i.e., cost recovery of implementation costs). Cost recovery alone does not remove the financial disincentive needed to further expand a utility’s commitment to maximizing energy efficiency and clean DG.
- *Reward Performance.* Some states have created shareholder incentives for implementing high-performance energy efficiency and clean DG programs. These incentives are usually in the form of a higher return on investment for energy efficiency if the programs demonstrate measured or verified success, i.e., an actual reduction of energy use from program implementation. States can also reward performance by using shared-savings mechanisms.

The first mechanism is critically important to allowing the second and third mechanisms to be meaningful. Removing disincentives first gives utility management a consistent framework for providing reliable, economic electric or gas service because it allows utilities to profitably invest in energy efficiency and DG resources without being penalized for lower sales volumes. Utilities can then aim to achieve implementation of high-performing energy efficiency and DG resources through superior management practices that result in assured cost recovery and lead to financial rewards for shareholders.

These three approaches, especially when used together, have helped provide a level playing field for demand-side resource consideration. A number of states, including Arizona, California, Connecticut,

Colorado, Idaho, Maine, Massachusetts, Minnesota, New Hampshire, New Mexico, New York, Nevada, Oregon, Rhode Island, and Washington, have had or are reviewing one or more of these forms of decoupling and incentive regulation.

Remove Disincentives Through Decoupling or Lost Revenue Adjustment Mechanisms

Traditional electric and gas utility ratemaking mechanisms unintentionally include financial disincentives for utilities to support energy efficiency and DG. This misalignment can be remedied through “lost revenue” adjustment mechanisms or mechanisms that “decouple” utility revenues from sales.

Lost Revenue Adjustment Mechanisms (LRAMs) allow a utility to directly recoup the “lost” revenue associated with not selling additional units of energy because of the success of energy efficiency or DG programs in reducing electricity consumption. The amount of lost revenue is typically 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. This amount of lost revenues is then directly returned to the utility. Some states have adopted these mechanisms, but experience has shown that LRAM can result in utilities being allowed more lost revenues than the energy efficiency program actually saved because the lost revenues are based on projected savings. Furthermore, because utilities still earn increased profits on additional sales, this approach leaves a disincentive for utilities to implement additional energy efficiency or support independent energy efficiency activities. The LRAM approach provides limited incentives and does not influence efficient utility operations company-wide like other decoupling approaches.

Decoupling is an alternative means of eliminating lost revenues that might otherwise occur with energy efficiency and DG resource implementation. Decoupling is a variation of more traditional performance-based ratemaking (PBR). Under traditional ratemaking, a utility’s rates are set at a fixed amount until the next rate case occurs at an undetermined point in time. Under traditional PBR, a utility’s rates are typically set for a predetermined number of years

(e.g., five years). This type of PBR is referred to as a “price cap” and is intended to provide utilities with a direct incentive to lower cost (and thereby increase profits) during the term of the price cap.

Decoupling is a variation of traditional PBR, and it sometimes is referred to as a particular form of “revenue cap.” Under this approach, a utility’s *revenues* are fixed for a specific term, in order to match the amount of anticipated costs incurred plus an appropriate profit. Alternately, a utility’s revenues per customer could be fixed, thus providing an automatic adjustment to revenues to account for new or departing customers. If the utility can reduce its costs during the term through energy efficiency or DG, it will be able to increase its profits. Furthermore, if a utility’s sales are reduced by any means, including efficiency, DG, weather, or economic swings, its revenues and therefore its profits will not be affected. This approach completely eliminates the throughput disincentive and does not require an accurate forecast of the amount of lost revenues associated with energy efficiency or DG. It does, however, result in the potential for variation in rates or prices, reflecting an adjustment to the relationship between total revenue requirements and total electricity or gas consumed by customers over the defined term. Such rate adjustments, or “true-ups,” are a fundamental aspect of the rate design resulting from decoupling profits from sales volumes.

Table 6.2.2 compares decoupling with a lost revenues approach and illustrates why decoupling is simpler and more effective than LRAM. As the table illustrates, decoupling appears to be a more comprehensive approach to aligning utility incentives. While it requires more effort to establish a complete decoupling mechanism, it avoids the downsides of lost revenue approaches.

As an example, California’s original decoupling policy, an Electric Rate Adjustment Mechanism (ERAM), was in place between 1982 and 1996 and was successful in reducing rate risk to customers and revenue risk to the major utility companies (Eto et al. 1993). California dropped its decoupling policy in 1996 when restructuring was initiated. When competition

Table 6.2.2: Approaches for Removing Disincentives to Energy Efficiency Investment: Decoupling vs. Lost Revenue Adjustments

Decoupling	Lost Revenue Adjustments
Removes sales incentive and all demand-side management (DSM) disincentives.	Removes some DSM disincentives.
Does not require sophisticated measurement and/or estimation.	Requires sophisticated measurement and/or estimation.
Utility does not profit from DSM, which does not actually produce savings.	Utility may profit from DSM, which does not actually produce savings.
Removes utility disincentive to support public policies that increase efficiency (e.g., rate design, appliance standards, customer initiated conservation).	Continues utility disincentive to pursue activities or support public policies that increase efficiency.
May reduce controversy in subsequent utility rate cases.	No direct effect on subsequent rate cases.
Reduces volatility of utility revenue resulting from many causes.	Reduces volatility of utility earnings only from specified DSM projects.

Source: Mosovitz et al. 1992.

did not deliver on its promise, California recently brought back a decoupling approach as part of a larger effort to reinvigorate utility-sponsored energy efficiency programs. Conversely, Minnesota tried a lost revenues approach and met strong customer opposition because there was no cap on the total amount of revenues that could be recovered.

While decoupling is a critical step in optimizing the benefits of energy efficiency, states are finding that decoupling alone is not sufficient. Two other related approaches states are taking include assurance for energy efficiency program cost recovery, and shareholder/company performance incentives to reward utilities for maximizing energy efficiency investment where cost effective.

Program Cost Recovery

One important element of utility energy efficiency and clean DG programs is the appropriate recovery of

costs. The extent to which this is a real risk for utilities depends upon the ratemaking practices in each state. Nonetheless, the perception of the risk can be a significant barrier to utilities, regardless of how real the risk. Under traditional ratemaking, utilities might be unable to collect any additional energy efficiency or DG expenses that are not already included in the rate base. Similarly, under a price cap form of PBR, utilities might be precluded from recovering "new" costs incurred between the periods when price caps are set. However, traditional ratemaking can nonetheless allow program cost recovery for well-performing energy efficiency or DG programs, if desired. If revenue caps are in place, well-performing program costs can be included as part of the overall revenue requirement, in the same way that supply-side fixed costs are usually included in revenue requirements. If energy efficiency/DG programs are not shown to meet minimum performance criteria, then these costs could be excluded from revenue requirements, i.e., these costs would not be passed on to ratepayers.

To overcome program cost recovery concerns, regulatory mechanisms can be used to assure that utility investments in cost-effective energy efficiency and DG resources will be recovered in rates, independent of the form of ratemaking in place. Under traditional ratemaking, an energy efficiency or DG surcharge could be included in rates and could be adjusted periodically to reflect actual costs incurred. Under a price cap form of PBR, the costs of energy efficiency and DG could be excluded from the price cap and could be adjusted periodically to reflect actual costs incurred. Many states with restructured electric industries have introduced a public benefits fund (PBF) that provides utilities with a fixed amount of funding for energy efficiency and DG, thus eliminating this barrier to utilities. For example, the New York Public Service Commission (PSC) approved a proposal in a ConEd rate case that included, among other demand-side measures, DSM program cost recovery through a PBF. In Colorado, a new bill has been introduced to require a Public Utilities Commission (PUC)

Rulemaking to address gas energy efficiency program cost recovery and regulatory disincentives to cost-effective energy efficiency programs (Colorado Legislature 2006).

Shareholder/Company Performance Incentives

Under traditional regulation, utilities may perceive that energy efficiency or clean DG investment conflicts with their profit motives. However, states are finding that once the throughput disincentive is addressed, utilities will look at cost-effective energy efficiency and clean DG as a potential profit center and an important resource alternative to meet future customer needs. Utilities earn a profit on approved capital investment for generators, wires, poles, transformers, etc. Incentive ratemaking can allow for greater levels of profit on energy efficiency or DG resources, recognizing that many benefits to these resources, such as improved reliability or reduced emissions, are not otherwise explicitly accounted for. Adjustment of approved rate-of-return for capital investment—supply- or demand-side resources—is an important policy tool for state regulators.

States, including Massachusetts and New Hampshire, are using profit or shareholder incentives to make energy efficiency and clean DG investments seem comparable to, or preferable to, conventional supply-side investments. With throughput disincentives removed, utilities can be rewarded with incentives stemming from superior program performance. Such incentives include a higher rate of return on capital invested in energy efficiency and clean DG, or equivalent earnings bonus allowances. Rewards require performance: independent auditing of energy efficiency/DG program effectiveness can drive the level of incentive. Conversely, poorly performing programs or components can be denied full cost recovery, providing a logical "stick" to the "carrot" of increased earnings potential, and ensuring that energy efficiency and clean DG program choices exclude those that only look good on paper. The savings that result from choosing the most cost-effective resources over less economical resources can be "shared" between ratepayers and shareholders, giving ratepayers the

benefits of wise resource use while rewarding management for the practices that allow these benefits to be secured.⁴²

Implementation of a package of incentive regulation initiatives might include: (1) stakeholder discussion of the issues, (2) state commission rulemaking or related initiative proposing a change from traditional ratemaking, and (3) clear and comprehensive direction from the state commission establishing the explicit rate structure or pilot program structure to be put in place.

Designing Effective Utility Incentives for Demand-Side Resources

Participants

A number of stakeholders are typically included in the design of decoupling and incentive regulations:

- *State Legislatures.* Utility regulation broadly affects all state residents and businesses. State energy policy is affected by and affects utility regulation. Legislation may be required to direct the regulatory commission to initiate an incentive regulation investigation or to remove barriers to elements like periodic resetting of rates without a comprehensive rate case. Legislative mandates can also provide funding and/or political support for incentive regulation initiatives.
- *State PUCs.* State PUCs have the greatest responsibility to investigate and consider incentive regulation mechanisms. Staff and commissioners oversee the stakeholder processes through which incentive regulation issues are discussed. PUCs are the ultimate issuers of directives implementing incentive regulation packages for regulated gas and electric utilities.
- *State Energy Offices/Executive Agencies.* State policies on energy and environmental issues are often driven by executive agencies at the behest of governor's offices. If executive agency staff are aware of the linkages between utility regulatory and ratemaking policies, it may be more likely that executive agency energy goals can be fostered by successful utility energy efficiency and clean DG programs. Attaining state energy and environmental policy goals hinges in part on the extent to which incentive regulation efforts succeed.
- *Energy Efficiency Providers.* Energy efficiency providers have a stake in incentive regulation initiatives. In some states, they contract with utilities to provide energy efficiency program implementation. In other states, energy efficiency providers such as Vermont's "Efficiency Vermont" serve as the managing entity for delivering energy efficiency programs.
- *DG Developers.* DG developers, like energy efficiency providers, are affected by any incentive regulation that reduces throughput incentives, since they are likely to be able to work more closely with utilities to target the locations that maximize the benefits that DG can bring by reducing distribution costs.
- *Utilities.* Vertically integrated utilities and distribution or distribution-transmission-only utilities are affected to the greatest degree by incentive regulation, as their approved revenue collection mechanisms are at the heart of incentive regulation issues. Incentive regulation approaches differ in their impacts on utilities depending in part on the degree of restructuring present in a state.
- *Environmental Advocates.* Energy efficiency and clean DG resources can provide low-cost environmental benefits, especially when targeted to locations requiring significant transmission and distribution investment. Environmental organizations can offer perspectives on using energy efficiency and clean DG as alternatives to supply-side options.
- *Other Organizations.* Other organizations, including consumer advocates and third-party energy

⁴² The utility industry uses the term "shared savings" in several ways. Alternative meanings include, for example, the sharing of savings between an end user and a contractor who installs energy efficiency measures. Throughout this *Guide to Action*, "shared savings" refers to shareholder/ratepayer sharing of benefits arising from implementation of cost-effective energy efficiency/DG programs that result in a utility obtaining economic energy efficiency/DG resources.

efficiency and clean DG providers, can provide cost-effectiveness information as well as perspectives on other complementary policies.

Interaction with Federal and State/Regional Policies

Incentive regulation is closely intertwined with almost all state-level energy policy involving electric and gas utility service delivery, since it addresses the fundamental issue of establishing a means for a regulated utility provider to recover its costs. The following state policies will be affected by changing to a form of incentive regulation:

- *Integrated Resource Planning (IRP) and Portfolio Management Policies.* These are an important complement to utility incentives because they provide vertically integrated utilities (through use of IRP) and distribution-only utilities (through use of portfolio management) with the long-term planning framework for identifying how much and what type of energy efficiency and clean DG resources to pursue. Without removing throughput disincentives, utilities undertaking IRP and portfolio management that include cost-effective energy efficiency and clean DG resources can lose revenue.
- *PBFs.* Also known as system benefits charges (SBCs), PBFs may eliminate the need for (or provide another way of addressing) cost recovery.
- *PBR Mechanisms.* PBR includes a host of mechanisms that can help achieve regulatory objectives. Many are tied to specific elements of ratemaking, such as price caps (i.e., a ceiling on the per unit rate charged for energy), revenue caps (i.e., a ceiling on total revenue), or revenue per customer caps. Typically, all PBR mechanisms are established with the goal of rewarding utility performance that results in superior customer service, reliability, or other measured outcome of utility company effort. Reducing the throughput disincentive is one important form of PBR, and if it is not addressed, the effectiveness of other aspects of PBR can be undermined.

- *Low-Income Weatherization.* Low-income weatherization and other energy efficiency improvement programs target the consumer sector with the least incentive to invest in energy efficiency. A fundamental market failure exists, for example, in the landlord-tenant relationship where landlords are responsible for building investment (e.g., new boilers) but tenants are responsible for paying utility bills. The result is that least-first-cost, rather than least-life-cycle-cost appliances are often installed. As with any other energy efficiency program, a utility company's incentive to see such programs succeed is reduced if overall profits remain linked to sales volume; thus, successful decoupling approaches can help to ensure low-income weatherization program success.

Best Practices: Designing Effective Incentive Regulations for Gas and Electric Utilities

The best practices identified below will help states develop effective incentive regulations to support implementation of cost-effective energy efficiency and DG programs.

- Survey the current regulatory landscape in your state and neighboring states.
- Determine if and how energy efficiency and clean DG are addressed in rate structures. In particular, determine if traditional ratemaking formulas exist. Do they create obstacles to promoting energy efficiency and clean DG?
- Gather information about potential incentive rate designs for your state.
- Assemble key stakeholders and provide a forum for their input on utility incentive options.
- Devise an implementation plan with specific timelines and objectives.

Evaluation

States are evaluating their decoupling activities to ensure program success. For example, independent evaluation of the Oregon initiative for Northwest Natural Gas included a summary of the program's intentions, recognition that deviations from forecast usage affects the amount of fixed costs recovered, and acknowledgement that partial, rather than full, decoupling was attained. States are evaluating decoupling activities to ensure program success. The report stated that the program had reduced the "variability of distribution revenues" and "alter[ed] NW Natural's incentives to promote energy efficiency" (Hansen and Braithwait 2005).

California's earlier decoupling policies (from 1982 to 1996), combined with intensive utility-sponsored DSM activity, resulted in comprehensive program evaluation. Existing reports illustrate the impact of California's decoupling during that period (Eto et al. 1993).

The following information is usually collected as part of the evaluation process to document additional energy efficiency or clean DG savings, customer rate impacts, and changes to program spending that arise due to changes to regulatory structures:

- Utility energy efficiency and clean DG program expenditure and savings information.
- Additional data on weather and economic conditions, to control for factors influencing retail sales other than program actions.
- Rate changes occurring during the program, if any, such as those arising from use of a balancing mechanism.

State Examples

Numerous states previously addressed or are currently exploring 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. There is renewed interest in incentive regulation due to recognition that barriers to energy efficiency still

exist, and utility efforts to secure energy efficiency and clean DG benefits remain promising. States are looking to incentive mechanisms to remove barriers in order to meet the cost-effective potential of clean energy resources.

California, Washington, Oregon, Maine, Maryland, Minnesota, New York, Idaho, Nevada, Massachusetts, Connecticut, New Hampshire, Rhode Island, New Mexico, and Arizona have had or are reviewing various forms of decoupling or incentive regulation, including performance incentive structures. The following state examples are listed in the approximate order of the extent to which decoupling mechanisms have been considered in the state.

California

California has recently re-adopted a revenue balancing mechanism that applies between rate cases and removes the throughput disincentive by allowing for rate adjustment based on actual electricity sales, rather than test-year forecast sales. The California Public Utility Commission (CPUC) established this mechanism to conform to a 2001 law that dictated policy in this area, stating that forecasting errors should not lead to significant over- or under-collection of revenue. As a result, California public utilities are returning to larger-scale promotion of energy efficiency through their DSM programs. Simultaneously, the CPUC is revising its policies to establish a common performance basis for energy efficiency programs that defer more costly supply-side investments.

California's rate policies are not new. Between 1983 and the mid-1990s, California's rate design included an ERAM, a decoupling policy that was the forerunner of today's policy and the model for other balancing mechanisms implemented by other states during the early 1990s. The impact of the original ERAM on California ratepayers was positive, with a negligible effect on rates, and led to reduced rate volatility. Overall utility energy efficiency program efforts in California, along with state building and appliance energy efficiency programs, have reduced peak capacity needs by more than 12,000 megawatts (MW) and continue to save about 40,000 gigawatt-

hours (GWh) per year of electricity (CEC and CPUC 2005).

California also implemented a shared-savings incentive mechanism in the 1990s. The CPUC authorized a 70%/30% ratepayer/shareholder split of the net benefits arising from implementation of energy efficiency measures in the 1994–1997 time frame. This mechanism first awarded shareholder earnings bonuses based on measured program performance. Between 1998 and 2002, the performance incentive was changed to reward “market transformation” efforts by the utilities. The incentives were phased out after 2002, because of the state’s overhaul of its energy efficiency policies, but recent ongoing activity pursuant to an energy efficiency rulemaking process promises to revisit shareholder incentive structures.

The CPUC continues to promote utility-sponsored energy efficiency efforts. A recent decision approves expenditures of \$2 billion over the 2006–2008 time period for the four major California investor-owned utilities. These expenditures will contribute toward overall spending goals of \$2.7 billion, with savings targeted at almost 5,000 peak MW, 23 terawatt-hours, and 444 million therms per year (cumulative through 2013). Under an ongoing rulemaking on energy efficiency policies, the CPUC is currently analyzing the risk/reward incentive structure that will apply over this time for the utilities.

Web sites:

http://www.cpuc.ca.gov/Published/Final_decision/40212.htm (energy efficiency goals)

http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/30826.pdf (shared savings)

http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/49859.pdf (current energy efficiency program spending plans with reference to new incentive plans)

Washington

In the early 1990s, Washington’s Utility and Transportation Commission (WUTC) implemented incentive regulations for Puget Sound Power and Light by establishing a revenue-per-customer cap, a

deferral account for revenues, and a reconciliation process. The mechanism lasted for a few years, but was phased out—without prejudice—a few years later when a package of alternative rate proposals was accepted.

Puget’s “Periodic Rate Adjustment Mechanism” (PRAM) was successful in achieving “dramatic improvements in energy efficiency performance,” and according to the WUTC, it “achieved its primary goal—the removal of disincentives to conservation investment” (WUTC 1993).

Washington held a workshop in May 2005 as part of a rulemaking to investigate decoupling natural gas revenues from sales volumes to eliminate disincentives to gas conservation and energy efficiency. Based on stakeholder feedback, the Utilities and Transportation Commission withdrew the rulemaking in favor of addressing decoupling through specific proposals (WUTC 2005).

Web site:

<http://www.wutc.wa.gov/webimage.nsf/6c548b093c5f816c88256efc00506bb6/0e699dd89acd5b1888256fdd00681656!>

Oregon

In September 2002, Oregon adopted a partial decoupling mechanism for one of its gas utilities, Northwest Natural Gas. The mechanism was established through a settlement process that established a price elasticity adjustment and a revenue deferral account, even though it did not fully decouple sales from profits. An evaluation found that the mechanism reduced, but did not completely remove, the link between sales and profits and that it “is an effective means of reducing NW Natural’s disincentive to promote energy efficiency” (Hansen and Braithwait 2005).

In the past, Oregon adopted and then abandoned lost revenue and shared savings mechanisms for two larger utility companies, PacifiCorp and Portland General Electric (PGE). Lack of support from customer groups, new corporate owners after acquisition, and shifting of DSM implementation to the non-utility sector ended these efforts.

The history and outcome of the NW Natural case in Oregon demonstrates that incentive regulation must be designed to address a number of stakeholders and many related issues that have financial impacts on ratepayers. In its approval of the regulation, the Oregon Commission acknowledged that it was only a "partial decoupling mechanism," but did recognize that decoupling allows for energy efficiency without harming shareholders (Oregon PUC 2002).

Web site:

<http://apps.puc.state.or.us/orders/2002ords/02%2D388.pdf> (Northwest Natural Gas Order)

Maine

In 1991, the Maine PUC adopted a revenue decoupling mechanism for Central Maine Power (CMP) on a three-year trial basis. "Allowed" revenue was determined in a rate case proceeding and adjusted annually based on changes in the number of utility customers. CMP's ERAM was not, however, a multi-year plan, so CMP was free to file a rate case at any time to adjust its "allowed" revenues. The mechanism quickly lost the support of major stakeholders in Maine due to a serious economic recession that resulted in lower sales levels. The lower sales levels caused substantial revenue deferrals that CMP was ultimately entitled to recover. CMP filed a rate case in October 1991 that would have increased rates at the time, but likely would have caused lower amounts of revenue deferrals. However, the rate case was withdrawn by agreement of the parties to avoid immediate rate increases during unfavorable economic times.

By the end of 1992, CMP's ERAM deferral had reached \$52 million. The consensus was that only a very small portion of this amount was due to CMP's conservation efforts and that the vast majority of the deferral resulted from the economic recession. Thus, ERAM was increasingly viewed as a mechanism that was shielding CMP against the economic impact of the recession, rather than providing the intended energy efficiency and conservation incentive impact. The situation was exacerbated by a change in the financial accounting rules that limited the amount of time that utilities could carry deferrals on their books. Maine's experiment with revenue cap regulation

came to an end on November 30, 1993, when ERAM was terminated by stipulation of the parties.

This experience illustrates the temporal dimension of decoupling approaches; immediate rate increases can be perceived negatively. However, under traditional forms of regulation, declining consumption trends such as those associated with economic downturns can also result in a need to increase rates to allow for fixed cost recovery.

Web site:

<http://www.state.me.us/mpuc/industries/electricity/index.html> (electric division of Maine PUC)

Maryland

The gas distribution side of Baltimore Gas and Electric (BG&E) and Washington Gas are each subject to a monthly revenue adjustment by the Maryland Public Service Commission. BG&E's "Rider 8" and Washington Gas' "Monthly Revenue Adjustment" (MRA) decouple weather and energy efficiency impacts from the revenue ultimately recovered by the gas companies. This decoupling mechanism achieves the aim of greater revenue stability for the gas companies, while preventing "over-recovery" from ratepayers during colder-than-normal heating seasons. The base revenue amount is set based on weather-normalized patterns of consumption, but monthly revenue adjustments are accrued based on actual revenues, and rates are adjusted monthly based on the accrued adjustments.

The rate structure has been in place for seven years for BG&E and is new for Washington Gas.

Web sites:

http://www.energetics.com/madri/pdfs/timmerman_101105.pdf (description by Maryland PSC Director of Rates and Economics)

<http://www.psc.state.md.us/psc/gas/gasCommodity.htm> (Maryland PSC gas commodity fact sheet)

Minnesota

Northern States Power, now Xcel Energy, petitioned the Minnesota PUC in 2004 for a partial decoupling



of its natural gas revenue requirement from sales, offering an annual true-up to rates to address reduced sales volume trends. In an approved offer of settlement, this portion of the company's petition was withdrawn, without prejudice, over concerns of the evidence of declining gas usage and whether the Commission had the legal authority to approve such a rate structure change.

Minnesota experimented with a lost revenue recovery approach in the 1990s, but terminated it in 1999 in favor of a "shared savings" approach because of the cumulative impact of the lost revenues. Its shared savings incentive mechanism is similar to the approach used by Massachusetts, Connecticut, New Hampshire, and Rhode Island (see page 6-35), where utility incentives increase if energy efficiency targets are exceeded.

Web site:

http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_1875_1802_3576-15057-5_406_652-0,00.html (gas decoupling information)

New York

In the 1990s, the New York Public Service Commission experimented with several different types of performance-based ratemaking, including revenue-cap decoupling mechanisms for Rochester Gas and Electric, Niagara Mohawk Power, and Consolidated Edison Company (ConEd) (Biewald et al. 1997). More recently, the Commission approved a joint proposal from all the stakeholders in a ConEd rate case that included significant increases in spending on DSM, a lost revenue adjustment mechanism, DSM program cost recovery through a PBF, and shareholder performance incentives. The Commission did not establish a decoupling mechanism, but left open the possibility to do so in another proceeding that is assessing DSM incentives for all New York utilities (NY PSC 2005).

Web site:

<http://www.dps.state.ny.us/fileroom.html> (CASE 04-E-0572-Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of ConEd of New York, Inc. for Electric Service)

Idaho

In May 2004, the Idaho PUC initiated a series of workshops to investigate the disincentives to energy efficiency that exist with traditional ratemaking. The Commission noted that disincentives are inherent in company-sponsored conservation programs and directed Idaho Power Company to examine balancing mechanisms and consider how much rate adjustment might be needed to remove energy efficiency investment disincentives.

The workshops resulted in a recommendation to establish a pilot project to allow Idaho Power Company to recover fixed-cost losses associated with new construction energy efficiency programs. This "lost revenue" approach is an initial foray by Idaho into incentive mechanisms that could eventually include a broader, fixed-cost true-up mechanism as part of the next general rate case.

Web site:

<http://www.puc.idaho.gov/internet/cases/summary/IPCE0415.html> (Idaho Power Company application, Commission Order, staff investigation documents)

Nevada

Nevada resurrected DSM efforts in 2001 in the wake of the California energy crisis. The two Nevada electric utilities recently participated in a DSM collaborative to obtain stakeholder input regarding the number and type of DSM programs, and have moved away from the strict Rate Impact Measure (RIM) Test to more lenient cost-effectiveness tests, allowing for greater DSM implementation. The Nevada IRP regulations include a shareholder performance incentive, whereby the electric utilities can place their DSM expenditures in rate base and earn the base rate of return on equity plus 5%. Nevada has not considered decoupling, in part because the state law appears to prevent balancing accounts for fixed cost recovery.

Web sites:

<http://energy.state.nv.us/efficiency/default.htm> (statewide conservation/efficiency resources)

http://gov.state.nv.us/pr/2005/PR_01-12ENERGY.htm (energy efficiency strategy)

Massachusetts, Connecticut, New Hampshire, and Rhode Island

While Maine is the only New England state with a history of a decoupling mechanism, other New England states have adopted shareholder incentive regulations that reward utility shareholders by allowing earnings on DSM program expenditures, analogous to allowing a rate of return on fixed, or “rate base” assets such as wires, poles, and generators. In these states, different levels of incentives are granted depending on the level of efficiency savings seen with DSM programs, also known as “shared savings.” There are typically three levels of program savings defined, which align with three levels of incentives granted. A “threshold level” defines the minimum savings that must be reached for any shareholder incentives to apply. A “target” level incentive is based on the goals of the most recent energy efficiency plan, and an “exemplary” level of incentives is seen if savings beyond the target level (above a certain amount) is achieved.

Web site:

<http://www.mass.gov/dte/restruct/competition/index.htm#PERFORMANCE> (Massachusetts Department of Telecommunications and Energy (DTE), Performance Based Ratemaking/Service Quality Proceedings)

New Mexico and Arizona

New Mexico and Arizona have recently undertaken legislative or regulatory efforts to address incentive regulation, although neither has an explicit decoupling policy in place. New Mexico’s energy efficiency legislation adopted earlier this year promotes and permits convenient cost recovery of both gas and electric utility DSM. In Arizona, the Southwest Gas Company has proposed a set of gas DSM programs in conjunction with decoupling sales from revenue.

Web site:

<http://www.cc.state.az.us/> (Arizona Corporation Commission)

What States Can Do

States are leveling the playing field for demand-side resources through improved utility rate design by removing disincentives through decoupling or lost revenue adjustment mechanisms. These actions make it possible for utilities to recover their energy efficiency and clean DG program costs, and/or provide shareholder and company performance incentives.

Key state roles include:

- *Legislatures.* Legislative mandate is often not required to allow state commissions to investigate and implement incentive regulation reforms. However, legislatures can help provide the resources required by state commissions to effectively conduct such processes. Legislative mandates can also provide political support or initiate incentive regulation investigations if the commission is not doing so on its own.
- *Executive Agencies.* Executive agencies can support state energy policy goals by recognizing the important role of regulatory reform in providing incentives to electric and gas utilities to increase energy efficiency and clean DG efforts. Their support can be important to encourage utilities or regulators concerned about change.
- *State Commissions.* State regulatory commissions usually have the legal authority to initiate investigations into incentive regulation ratemaking, including decoupling. Commissions have the regulatory framework, institutional history, and technical expertise to examine the potential for decoupling and consider incentive ratemaking elements within the context of state law and policy. State commissions are often able to directly adopt appropriate incentive regulation mechanisms after adequate review and exploration of alternative mechanisms.



Action Steps for States

States can take the following steps to promote incentive regulation for clean energy, as well as overall customer quality and lower costs:

- Survey the current utility incentive structure to determine how costs are currently recovered, whether any energy efficiency programs and shareholder incentives are in place, and how energy efficiency and DG costs are recovered.
- Review available mechanisms.
- Review historical experience in the relevant states.
- Open a docket on these issues.
- Determine which incentive regulation tools might be appropriate.
- Engage commissioners and staff and find consensus solutions.

Information Resources

State and Regional Information on Incentive Regulation Efforts

State	Title/Description	URL Address
California	Background and historical information on CPUC shared savings mechanism in the mid-1990s and general energy efficiency policies.	http://www.cpuc.ca.gov/Published/Final_decision/30826.htm
	California Energy Commission (CEC).	http://www.energy.ca.gov/
	California's "Energy Action Plan II," an implementation roadmap for California energy policies.	http://www.cpuc.ca.gov/PUBLISHED/REPORT/49078.htm
	CPUC.	http://www.cpuc.ca.gov/static/index.htm
	CPUC current rulemaking on energy efficiency policies.	http://www.cpuc.ca.gov/static/energy/electric/energy+efficiency/rulemaking/docs_inr0108028.htm
	CPUC Decision establishing energy savings goals for energy efficiency program years 2006 and beyond. September 23, 2004.	http://www.cpuc.ca.gov/Published/Final_decision/40212.htm
	CPUC Decision on energy efficiency spending—phase I. September 22, 2005.	http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/49859.htm
Colorado	House Bill 1147 addresses funding and cost recovery mechanism for natural gas energy efficiency.	http://www.leg.state.co.us/clics2006a/csl.nsf/fsbillcont3/CCC36D78DB009296872570CB006CBA70?open&file=1147_01.pdf
Idaho	Idaho PUC, Case No. IPC-E-04-15. Idaho Power—Investigation of Financial Disincentives. This Web site summarizes regulatory proceedings and workshop results regarding the Commission's investigation of financial disincentives to energy efficiency programs for Idaho Power under Case No. IPC-E-04-15.	http://www.puc.idaho.gov/internet/cases/summary/IPCE0415.html
Maryland	Maryland PUC, Gas Commodity Rate Structure reference.	http://www.psc.state.md.us/psc/gas/gasCommodity.htm
Mid-Atlantic Distributed Resources Initiative (MADRI)	MADRI is developing a model rule, called the Electric Utility Revenue Stability Adjustment Factor, to reduce a utility's throughput incentive.	http://www.energetics.com/madri/
Oregon	Oregon PUC, Order on NW Natural Gas Decoupling. This order reauthorized deferred accounting for costs associated with NW Natural Gas Company's conservation and energy efficiency programs.	http://apps.puc.state.or.us/orders/2002ords/02%2D388.pdf
Washington	WUTC, Natural Gas Decoupling Investigation. This Web site describes the Commission's action to investigate decoupling mechanisms to eliminate disincentives to gas conservation and energy efficiency programs.	http://www.wutc.wa.gov/webimage.nsf/6c548b093c5f816c88256efc00506bb6/0e699dd89acd5b1888256fdd00681656
General	The Regulatory Assistance Project (RAP) has published several reports on decoupling and financial incentives.	http://www.raponline.org

General Articles and Web Sites About Utility Incentives for Demand-Side Resources

Title/Description	URL Address
Barriers to Energy Efficiency. This presentation identifies barriers to energy efficiency programs, describes differences between lost base revenue adjustments and revenue decoupling as ways to remove such barriers, and presents other solutions for consumer advocates and regulators to further promote energy efficiency.	http://www.raponline.org/Slides/MACRUCEnergyEfficiencyBarriersWS%2Epdf
Breaking the Consumption Habit: Ratemaking for Efficient Resource Decisions. This Natural Resources Defense Council (NRDC) article from The Electricity Journal (December 2001) describes the concept and history of decoupling mechanisms and calls for re-examination of the mechanisms in order to remove disincentives to deployment of distributed energy resources under the restructured electric industry.	http://www.nrdc.org/air/energy/abreaking.asp
Clean Energy Policies for Electric and Gas Utility Regulators. This article examines policy options for distributed energy resources (e.g., EE/RE and DG) and rate design, and also discusses the importance of regulatory financial incentives to support dissemination of distributed energy resources.	http://www.raponline.org/Pubs/IssueLtr/RAPjan2005.pdf
Decoupling and Public Utility Regulation (publication no. NRRI 94-14). Graniere, R. and A. Cooley. National Regulatory Research Institute. August 1994. This report explores the relationship between decoupling and public utilities regulation. One of the conclusions is that decoupling could preserve the financial integrity of the utility and protect the environment, but at the cost of a high probability of periodic increases of electricity prices.	http://www.nrri.ohio-state.edu/phpss113/search.php?focus=94-14&select=Publications
Decoupling vs. Lost Revenue: Regulatory Considerations. Moskovitz D., C. Harrington, T. Austin. May 1992. This article identifies characteristics and distinctions between decoupling and lost revenue recovery mechanisms and concludes that decoupling is preferable because unlike the lost-base revenue approach, decoupling removes the utilities' incentive to promote new sales and does not provide utilities with an incentive to adopt ineffective DSM programs.	http://www.raponline.org/Pubs/General/decoupling.pdf
Financial Disincentives to Energy Efficiency Investment. Direct Testimony of Ralph Cavanagh, NRDC, Wisconsin, 2005. This testimony identifies financial disincentives to the Wisconsin Power and Light Company's cost-effective energy efficiency programs and identifies solutions.	http://psc.wi.gov/apps/erf_search/default.aspx (PSC Ref.# 31965, filed April 4, 2005)
Joint Statement of NRDC and American Gas Association on Utility Incentives for Energy Efficiency. This statement identifies ways to promote both economic and environmental progress by removing barriers to natural gas distribution companies' investments in urgently needed and cost-effective resources and infrastructure.	http://www.aga.org/Content/ContentGroups/Rates/AGANRDCJointStatement.pdf
Link to All State Utility Commission Web sites. This NARUC Web site provides links to all state utility commission sites.	http://www.naruc.org/displaycommon.cfm?an=15
Southwest Energy Efficiency Project (SWEEP). SWEEP is a nonprofit organization promoting greater energy efficiency in Southwest states.	http://www.swenergy.org/

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CEC and CPUC. 2005. CEC and CPUC. Draft Energy Action Plan II, Implementation Roadmap For Energy Policies. July 27.	http://www.energy.ca.gov/energy_action_plan/2005-07-27_EAP2_DRAFT.pdf
Colorado Legislature. 2006. Colorado House Bill 06-1147.	http://www.leg.state.co.us/clics2006a/csl.nsf/fsbillcont3/CCC36D78DB009296872570CB006CBA70?open&file=1147_01.pdf
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NY PSC. 2005. Case 04-E-0572. Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of ConEd, Order Adopting a Three-Year Rate Plan. March 24. New York PSC.	http://media.corporate-ir.net/media_files/nys/ed/Three-YearRateplan-3-24-05.pdf
Oregon PUC. 2002. Order No. 02-634, Application for Public Purposes Funding and Distribution Margin Normalization. Oregon PUC. September 12.	http://apps.puc.state.or.us/ Click on Orders, View Orders 2000 to Current, List Orders for 2002, Order No. 02-634.
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6.3 Emerging Approaches: Removing Unintended Utility Rate Barriers to Distributed Generation

Policy Description and Objective

Summary

The unique operating profile of clean energy supply projects (i.e., renewable and combined heat and power [CHP])⁴³ may require different types of rates and different rate structures. However, if not properly designed, these additional rates and charges can create unnecessary barriers to the use of renewables and CHP. Appropriate rate design is critical to allow for utility cost recovery while also providing appropriate price signals for clean energy supply.

Customer-sited clean energy supply projects are usually interconnected to the power grid and may purchase electricity from or sell to the grid. Electric utilities typically charge these customers special rates for electricity and for services associated with this interconnection. These rates include exit fees, standby rates, and buyback rates. For more information on interconnection, see Section 5.4, *Interconnection Standards*.

As with interconnection, states can play an important role in balancing the utility's need to recover costs for services provided against the clean energy project's benefits in the form of grid congestion relief, reliability enhancement, and emissions reductions. States are finding that strategically sited clean energy supply can be a lower-cost way to meet growing demand, particularly in grid-congested areas.

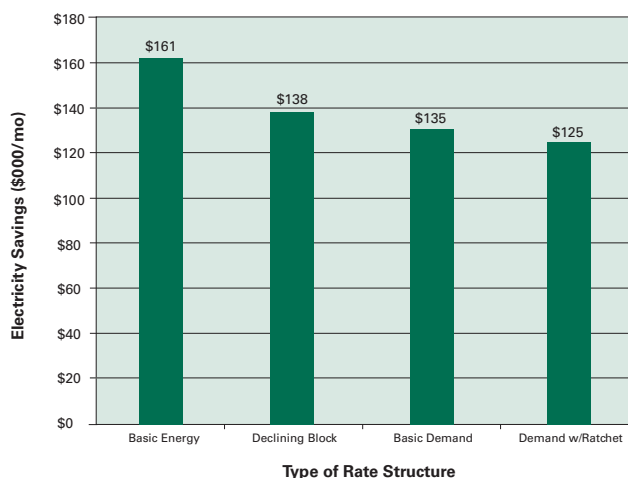
The charges for services provided to interconnected clean energy projects, the price paid for electricity

The state public utility commission (PUC), in setting appropriately designed electric and natural gas rates, can support clean distributed generation (DG) projects and avoid unnecessary barriers, while also providing appropriate cost recovery for utility services on which consumers depend.

sold to the grid, and the basic design of electric utility rates can have a significant effect on a project's economic viability. To illustrate, a 1.4 megawatt (MW) CHP project's savings can range from \$161,000 to \$125,000 per month (\$432,000 annual savings differential), depending on the rate structures (see Figure 6.3.1). This can make or break a project's profitability.

Interconnection with the grid can serve a variety of different needs that have potential rate impacts. Depending on the specific renewable energy/CHP system design, operating conditions, and the load requirements of the end user, the onsite clean energy

Figure 6.3.1: Effect of Rate Structure on Electric Savings Revenue for 1.4 MW CHP Project



Source: EEA 2005.

⁴³ Unless otherwise stated, this document refers to smaller-scale, customer-sited DG, not large wind farms or large merchant electricity generators using CHP. These large renewable and CHP systems interact with the electric grid more like central station plants and have different rate and grid interaction issues than the technologies addressed here.

system may provide anywhere from zero to greater than 100% of the end user's electricity needs at any given moment. When the unit produces less than the customer's full electricity requirements, power from the grid is used to supplement (or supply in full) the customer's electricity need. If the system produces more than is required by the customer, it may be able to export power back to the grid and receive payment in return.

In nearly all clean energy supply installations—even those sized to serve the customer's full electric load—grid power may be needed at times due to a forced outage, planned maintenance outage, or a shut-down for economic reasons. Purchasing power from the grid for these purposes is usually more cost-effective than providing redundant onsite generation. Utilities typically charge special rates to provide this service, generically known as “standby rates.” Some utilities charge energy users an exit fee when they reduce or end their use of electricity from the grid.

In addition to electric rates, if natural gas is used to fuel the CHP unit, gas rates will also affect the CHP system economics. All of these rates can have a critical effect on the viability of clean energy projects and can be addressed by states.

Rates Background

Under conventional electric utility ratemaking, electricity suppliers are paid largely according to the amount of electricity they sell. If customers purchase less electricity due to onsite generation projects (or energy efficiency projects), the utility has less income to cover its fixed costs. Utilities have applied a variety of rates to recover reduced income due to end-use efficiency, onsite generation, or other changes in customer operation or mix. States have begun exploring whether these alternative rates and charges are creating unanticipated barriers to the use of clean energy supply.

These concerns and other results of electric restructuring have triggered new proposals for rate designs that “decouple” utility profits from sales volume. One

category of such approaches is “performance-based” rates, which base the utility's income on its efficiency, rather than simply sales volume. This is one of several strategies that states are applying to avoid undue barriers and to provide appropriate price signals for renewable and CHP projects that balance the rate impacts on utilities with the societal benefits (including electric grid benefits) of renewable and CHP generation. For more information on decoupling utility profits from electric sales, see Section 6.2, *Utility Incentives for Demand-Side Resources*.

Some of the specific rate issues that states are addressing include:

- **Exit Fees.** When facilities reduce or end their use of electricity from the grid, they reduce the utility's revenues that cover fixed costs on the system. The remaining customers may eventually bear these costs. This can be a problem if a large customer leaves a small electric system. Exit (or stranded asset recovery) fees are typically used only in states that have restructured their electric utility. To avoid potential rate increases due to the load loss, utilities sometimes assess exit fees on departing load to keep the utility whole without shifting the revenue responsibility for those costs to the remaining customers.

States may wish to explore whether other methods exist to make utilities whole. Because many factors affect utility rates and revenues (e.g., customer growth, climate, fuel prices, and overall economic conditions), it does not naturally follow that any reduction in load will necessarily result in cost increases.

Some states that have restructured their electric industry have imposed exit fees as a means to assure recovery of a special category of historic costs called “stranded costs or stranded asset recovery.” In some states, such as Texas, these “competitive transition charges” have expired as the restructuring process is completed. States have exempted CHP and renewable projects from these exit fees to recognize the economic value of these projects, including their grid congestion relief and reliability enhancement benefits. For example,

Massachusetts and Illinois exempted some or all CHP projects from their stranded cost recovery fees.

- *Standby and Related Rates.* Facilities that use renewables or CHP usually need to provide for standby power when the system is unavailable due to equipment failure, during periods of maintenance, or other planned outages.

Electric utilities often assess standby charges on onsite generation to cover the additional costs they incur as they continue to provide adequate generating, transmission, or distribution capacity (depending on the structure of the utility) to supply onsite generators when requested (sometimes on short notice). The utility's concern is that the facility will require power at a time when electricity is scarce or at a premium cost and that it must be prepared to serve load during such extreme conditions.

The probability that any one generator will require standby service at the exact peak demand period is low and the probability that all interconnected small-scale DG will all need it at the same time is even lower. Consequently, states are exploring alternatives to standby rates that may more accurately reflect these conditions.

States are looking for ways to account for the normal diversity within a load class⁴⁴ and consider the probabilities that the demand for standby service will coincide with peak (high-cost) hours versus the benefits that CHP and renewables provide to the system.

- *Buyback Rates.* Renewable and CHP projects may have electricity to sell back to the grid, either intermittently or continuously. The payment received for this power can be a critical component of project economics. The price at which the utility is willing to purchase this power can vary widely. It is also affected by federal and state requirements.

The Public Utilities Regulatory Policy Act (PURPA) sets standards for buyback rates at the utility's avoided cost (i.e., the cost of the next generating resource available to the utilities). When large renewable or CHP generators have open access to wholesale electricity markets, they usually have access to competitive markets for both appropriate sales and purchase of electricity, including standby services. These markets usually include the value of both the energy and transmission, whereas the latter is usually not included in regulated rates. In regulated markets, states are responsible for helping generators and utilities establish appropriate buyback rates.

Net metering regulations allow small generators (typically renewable energy up to 100 kW)⁴⁵ a guaranteed purchase for their excess generation at a distribution utility's retail cost. While this price is higher than the utility's wholesale cost of electricity, it also includes the cost of delivery and is typically seen as a reasonable rate for small generators. Net-metering programs typically also address interconnection in a simple way, which is appropriate for small renewable projects. (For more information on net metering, see Section 5.4, *Interconnection Standards*.)

- *Gas Rates for CHP Facilities.* Some states, including New York and California, have established special favorable natural gas rates for CHP facilities. For example, New York has frozen gas rates for DG facilities until at least 2007 to provide economic certainty to developers.

State Objectives

A key state PUC objective is to ensure that consumers receive reliable power at the lowest cost. In approving rates, the PUC can support renewable and CHP projects and avoid unanticipated barriers, while also providing appropriate cost recovery for the utility services on which consumers depend.

⁴⁴ For example, some industrial facilities run three shifts per day while others only run one shift per day. This would lead to a three-fold disparity between peak and minimum power demand in two otherwise identical facilities.

⁴⁵ Note that the definition of a renewable resource varies by state.

Benefits

Appropriately designed rates can promote the development of CHP and renewables, leading to enhanced reliability and economic development while protecting utility ratepayers from excessive costs.

The benefits of increasing the number of clean DG projects include expanding economic development, reducing peak electrical demand, reducing electric grid constraints, reducing the environmental impact of power generation, and helping states achieve success with other clean energy initiatives. The application of DG in targeted load pockets can reduce grid congestion, potentially deferring or displacing more expensive transmission and distribution infrastructure investments. A 2005 study for the California Energy Commission (CEC) found that strategically sited DG yields improvements to grid system efficiency and provides additional reserve power, deferred costs, and other grid benefits (Evans 2005). Increased use of clean DG can slow the growth-driven demand for more power lines and power stations.

States with Existing Rates for Renewables or CHP

As of early 2005, several states have evaluated or have begun to evaluate utility rate structures and have made changes to promote CHP and renewables as part of their larger efforts to support cost-effective clean energy supply as an alternative to expansion of the electric grid. This type of work is typically conducted by the state PUC through a formal process (docket or rulemaking) that allows input from all stakeholders.

California and New York have established revised standby rate structures that are more favorable to CHP and renewables. Another state has found that designing a standby rate structure that bases the charges on the onsite generator's capacity rather than the amount of capacity supplied (thus creating a high charge even if there is no outage) has resulted in a dramatic decline in the number of CHP projects proposed where this rate exists.

Some states have incorporated exit fee exemptions into their electric restructuring programs for existing loads that leave a utility's distribution system. For example, Illinois, Massachusetts, and New York allow certain exit fee exemptions for loads that are replaced by clean onsite generation, specifically CHP and renewables.

More than 30 states have net metering regulations that provide a guaranteed purchase of small generators' excess generation at the distribution utility's retail cost.

Two states have established special gas rates for electric generators, including CHP projects. California has implemented special gas tariffs for all electric generators. In 2003, the New York Public Service Commission (PSC) ordered natural gas companies to create a rate class specifically for DG users and certify that they had removed rate-related barriers to DG.

Designing Fair and Reasonable Utility Rates for Clean Energy Supply

States consider a number of key elements as they develop new strategies that ensure utility rates allow renewables and CHP to compete on a level playing field and that recognize their benefits while providing a reliable electric system for consumers and adequate cost recovery for utilities.

Participants

- *State PUC.* Rates typically are approved by the state PUC during a utility rate filing or other related filing. The PUC staff are the focal point for evaluating costs and benefits to generators, utilities, consumers, and society as a whole. Many PUCs conduct active rate reviews in order to maintain consistency with changing policy priorities.
- *Utilities.* Utilities play a critical role in rate-setting. Their cost recovery and overall economic focus have historically revolved around volumetric rates that reward the sale of increased amounts of electricity. Anything that reduces electricity sales

(including clean DG, energy efficiency, and departing load) also reduces utility income and may make it more difficult to cover fixed costs if the fixed components of existing tariffs are not calculated to match utility fixed costs. This creates a disincentive for utilities to support such projects. New ways of setting rates (e.g., decoupling or performance-based rates) can make utility incentives consistent with those of clean energy developers and policymakers. (For more information on policies that can serve as utility incentives for clean energy, including decoupling utility profits from electric sales, see Section 6.2, *Utility Incentives for Demand-Side Resources*.)

- *Renewable Energy and CHP Project Developers.* Project developers establish the benefits of clean technology and the policy reasons for developing rates that encourage their application. They participate in rulemakings and other proceedings, where appropriate.
- *Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs).* While not directly involved in utility rate-setting, these entities manage electricity infrastructure in some regions of the country. They interact with CHP and renewable generators and may also be involved in ratemaking discussions.
- *State Energy Offices, Energy Research and Development Agencies, and Economic Development Authorities.* These state offices often have an interest in encouraging renewables and CHP as a strategy to deliver a diverse, stable supply of reasonably priced electricity. They may be able to provide objective data on actual costs and help balance many of the issues that must be addressed.
- *Current and Future Energy and CHP Users.* Energy users have a considerable stake in the rates discussion. In some states, users are encouraged by the PUC to participate in utility hearings. They can also provide input on required rates and technical requirements and help recommend policies to accommodate utility needs.

Interaction with Federal Policies

PURPA Sec. 210 regulates interactions between electric utilities and renewable/CHP generators that are Qualifying Facilities (QFs).⁴⁶ PURPA played a role in structuring these relationships, most notably in developing the concept of rates based on avoided cost. In noncompetitive markets, QF status may be the only option for non-utility generators to participate in the electricity market.

Interaction with State Policies

Designing utility rates to support clean energy can be coordinated with other state policies.

- Ratemaking issues are often closely tied to a state's electric restructuring status. For example, exit fees typically exist only in restructured states. When generators have open access to electric markets, they can often provide for their own standby services through the market. This is especially true for larger generators that can negotiate market rates.
- States have explored decoupling utility returns from the volume of electricity sold. This issue addresses the basic divergence of interest between utilities and onsite generators and can be very important when examining rates for clean DG. (For more information on decoupling, see Section 6.2, *Utility Incentives for Demand-Side Resources*.)
- If a renewable portfolio standard (RPS) and/or a public benefits fund (PBF)/clean energy fund are in place, unreasonable standby rates and exit fees may unintentionally hamper their success by rendering clean energy projects uneconomical. (See Section 5.1, *Renewable Portfolio Standards*, and Section 5.2, *Public Benefits Funds for State Clean Energy Supply Programs*.)

⁴⁶ A qualifying facility is a generation facility that produces electricity and thermal energy and meets certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) under PURPA.

- States may consider working with utilities to offer credits to customer-sited clean energy supply in areas of high grid congestion. This can be the most cost-effective strategy to reduce chronically high congestion costs.

Program Implementation and Evaluation

Addressing rate issues requires different solutions depending on the status of electricity restructuring in each state and other characteristics of the local generating mix and regulatory situation. This section describes some of the issues that states have considered as they undertake the task of developing rates that support clean energy technologies.

Administering Body

Rate-appropriate decisions are almost always within the purview of a state's PUC. However, many state PUCs do not regulate municipal and cooperative utilities standby rates. (Vermont is an example of a state where PUCs do regulate municipal utilities standby rates.) While PUCs are familiar with many of the traditional rate issues, some states are beginning to explore new approaches to balance rate reasonableness with utility cost recovery, particularly for clean energy supply.

Key Issues in Ensuring Rate Reasonableness

- States are attempting to ensure that rates are based on accurate measurement of costs and benefits of clean DG, and further that such costs and benefits are distinct from those already common to the otherwise applicable rate classification. For example, California has funded a study that investigates whether DG, demand response, and localized reactive power sources enhance the performance of an electric power transmission and distribution system. This report presents a methodology to determine the characteristics of distributed energy resource projects that enhance the performance of a power delivery network and quantify the potential benefits of these projects (Evans 2005).

Best Practices: Implementing Rates to Support CHP and Renewable Energy

The following best practices, based on state experiences, can help states implement rates that support CHP and renewable energy.

- Ensure that state PUC commissioners and staff have current and accurate information regarding the rate issues for CHP and renewables and their potential benefits for the generation system. These new technologies may not have been considered for rates that were developed before the more widespread application of renewable energy and CHP.
 - Open a generic PUC docket to explore the actual costs and system benefits of onsite clean energy supply and rate reasonableness, if these issues cannot be addressed under an existing open docket.
 - Coordinate with other state agencies that can lend support. State energy offices, energy research and development offices, and economic development offices can be important sources of objective data on actual costs and benefits of onsite generation.
- States may wish to explore ways to ensure that the benefits of clean DG that can accrue to the upstream electricity grid are reflected in rates. These benefits include increased system capacity, potential deferral of transmission and distribution (T&D) investment, reduced system losses, improved stability from reactive power, and voltage support. In restructured states, these benefits may be external to the regulated utility, but it is important that rates capture these elements to ensure optimum capital allocation by both regulated and unregulated parties.
 - States conduct annual program evaluation of the value of standby rates in encouraging CHP. Such rigorous program evaluation may impose costs and resource requirements on state PUCs.

State Examples

Exit Fees

California

There are several types of exit and transition fees in the California market, and they are handled differently depending on the specific utility. Fee exemptions exist for various classes of renewable and CHP systems, including:

- Systems smaller than 1 MW that are net metered or are eligible for California Public Utilities Commission (CPUC) or CEC incentives for being clean and super-clean.
- Ultra-clean and low-emission systems that are 1 MW or greater and comply with California Air Resources Board (CARB) 2007 air emission standards.
- Zero emitting, highly efficient (> 42.5%) systems built after May 1, 2001.

Illinois

In Illinois, a utility can assess exit fees for stranded costs until December 31, 2006. The rule is fairly stringent and specific about the instances that trigger this fee. The rule does, however, provide an exemption for DG and CHP. A departing customer's DG source must be sized to meet its thermal and electrical needs with all production used on site.

Web site:

<http://www.ilga.gov/legislation/ilcs/ilcs4.asp?DocName=022000050HArt%2E+XVI&ActID=1277&ChapAct=220%26nbsp%3BILCS%26nbsp%3B5%2F&ChapterID=23&ChapterName=UTILITIES&SectionID=21314&SeqStart=40500&SeqEnd=45100&ActName=Public+Utilities+Act%2E>

Massachusetts

In Massachusetts, exit fees can be assessed for DG applications greater than 60 kilowatts (kW). Renewable energy technologies and fuel cells are exempt, regardless of their power rating. Massachusetts' restructuring law, however, specifically provides that distribution

companies cannot charge exit fees to renewable or DG facilities unless certain conditions are met. These specified conditions include a prerequisite that the utility must see a "significant" revenue loss from non-utility generation. "Significant" is not defined and has led to unnecessary tension between utilities and DG users on issues of meter ownership and generator performance reporting.

Web site:

<http://www.magnet.state.ma.us/dpu/restruct/96-100/cmr11-2.pdf>

Standby Rates

California

California Senate Bill 28 1X (passed in April 2001) requires utilities to provide DG customers with an exemption from standby reservation charges. The exemptions apply for the following time periods:

- Through June 2011 for customers installing CHP-related generation between May 2001 and June 2004.
- Through June 2006 for customers installing non-CHP applications between May 2001 and September 2002.
- Through June 2011 for "ultra-clean" and low-emission DG customers 5 MW and less installed between January 2003 and December 2005.

California utilities submitted DG rate design applications in September 2001. A docket was opened to allow parties to file comments on the utility's proposals in October and November 2001. After a year, the CPUC decided to incorporate rate design proposals into utility rate design proceedings. Each utility's rate case is different, but in general, the rate design includes a contracted demand with high fixed charges.

New York

In July 2003, the New York PSC voted to approve new standby rates for utilities' standby electric delivery service to DG customers and standby service to independent wholesale electric generating plants that import electricity as "station power" to support their operations (NYPSC Case 99-E-1470).⁴⁷ A key consideration was for the rates to result in onsite generation running when it is less expensive than purchasing power from the grid.

Under the guidelines previously adopted by the New York PSC, standby rates are expected to reflect a more cost-based rate design that avoids relying on the amount of energy consumed (per-kilowatt-hour, or kWh) to determine the charges for delivery service. Instead, the new rates recognize that the costs of providing delivery service to standby customers should more accurately reflect the size of the facilities needed to meet a customer's maximum demand for delivery service at any given time. This varies not with the volume of electricity delivered, but primarily with the peak load (per-kilowatt) that must be delivered at any particular moment.

For certain categories of standby customers, the New York PSC voted to approve a series of options for the transition to the new rate structure. Specifically, pre-existing DG customers are offered two options. They can either shift immediately to the new standby rate or continue under the existing rate for four years and then phase into the standby rate over the next four years. Because the new rates align the customer cost with the potential benefit of onsite power to the grid, there are some cases in which it is more favorable for customers to opt in to the new rates, which also provide greater reliability to the grid.

Recognizing the environmental benefits of certain energy sources, customers that begin DG operations between August 1, 2003, and May 31, 2006, and use certain environmentally beneficial technologies or

small CHP applications of less than 1 MW, can choose among three options. They can elect to remain on the current standard rate indefinitely, shift immediately to the new standby rate, or opt for a five-year phase-in period beginning on the effective date of the new standby rates.

Web site:

<http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Web?SearchView&View=Web&Query=%5BCaseNumber%5D=99-E-1470&SearchOrder=4&Count=All>

Gas Rates for DG Customers

New York

The New York PSC directed electric utilities to consider DG as an alternative to traditional electric distribution system improvement projects. The Commission also recognized that increased gas use for DG can create positive rate effects for gas consumers by providing increased coverage of fixed costs. They therefore ordered natural gas companies to create a rate class specifically for DG users. The ceilings for these rates are to be frozen until at least the end of 2007 to enable the emerging DG industry to predict gas rates for an initial period of time.

Web site:

[http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Web/047CACD1286149B285256DF10075636D/\\$File/doc11651.pdf?OpenElement](http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Web/047CACD1286149B285256DF10075636D/$File/doc11651.pdf?OpenElement)

What States Can Do

Action Steps for States

States have chosen a wide variety of approaches and goals in developing their rates. The "best practices" common among these states have been explored above. Suggested action steps are described as follows.

⁴⁷ The new rates do not apply to Niagara Mohawk, which had previously submitted—and gained approval for—a standby rate external to this process. The Niagara Mohawk rate is less favorable to DG than the rate described herein, and presents an on-going barrier to DG deployment in their service territory.



States That Have Addressed Rates for Renewables or CHP

A top priority after establishing rates is to identify and mitigate issues that might adversely affect the success of the rates. States can:

- Monitor utility compliance and impact on ratepayers. Significant, unanticipated, or adverse impacts on ratepayers can be addressed through implementing or adjusting cost caps or other appropriate means.
- Monitor the pace of installation of new renewable resources and CHP to make sure that the rates are working.

States That Have Not Addressed Rates for Renewables or CHP

States have found that political support from PUC officials and staff is helpful in establishing appropriate rates. Once general support for goals has been established, a key step is to facilitate discussion and negotiation among key stakeholders toward appropriate rate design. More specifically, states can:

- Ascertain the level of general interest and support for renewable energy and CHP in the state among public office holders and the public. If awareness is low, consider implementing an education program about the environmental and economic benefits of accelerating the development of renewable energy and CHP.
- Identify existing renewable portfolio standards or other policies in place or pending that might be significant drivers to new onsite clean energy supply. The rate issue may arise in that context.
- Establish a working group of interested stakeholders to consider design issues and develop recommendations for favorable rates.
- Open a generic PUC docket to explore actual costs and system benefits of onsite clean energy supply and rate reasonableness.

Information Resources

Federal Resources

Title/Description	URL Address
The U.S. Environmental Protection Agency's (EPA's) CHP Partnership is a voluntary program that seeks to reduce the environmental impact of energy generation by promoting the use of CHP. The Partnership helps states identify opportunities for policy development (energy, environmental, economic) to encourage energy efficiency through CHP and can provide additional assistance to states in assessing and implementing reasonable rates.	http://www.epa.gov/chp/

General Articles About Ratemaking

Title/Description	URL Address
Accommodating Distributed Resources in the Wholesale Market. This Regulatory Assistance Project (RAP) publication examines the different functions that distributed resources can perform and the barriers to these functions. Policy and operational approaches to promoting distributed resources in wholesale markets are identified.	http://www.raponline.org/showpdf.asp?PDF_URL=%22Pubs/DRSeries/DRWhIIMkt.pdf%22
Electricity Transmission: A Primer. This RAP publication was prepared for the National Council on Electric Policy in connection with the Transmission Siting Project. The primer is intended to help policymakers understand the physics, economics, and policies that influence and govern the electric transmission system.	http://www.raponline.org/showpdf.asp?PDF_URL=Pubs/ELECTRICITYTRANSMISSION%2Epd
Energy Efficiency's Next Generation: Innovation at the State Level. American Council for an Energy-Efficient Economy (ACEEE), report number E031, November 2003.	http://www.aceee.org/pubs/e031.htm

Other Resources

Title/Description	URL Address
Regulatory Requirements Database for Small Generators. Online database of regulatory information for small generators. Includes information on standby rates and exit fees, as well as environmental permitting and other regulatory information.	http://www.eea-inc.com/rrdb/DGRegProject/index.html
The U.S. Combined Heat and Power Association (USCHPA) brings together diverse market interests to promote the growth of clean, efficient CHP in the United States. USCHPA can assist states in rate design.	http://www.uschpa.org

Examples of State Legislation and Program Proposals

State	Title/Description	URL Address
Illinois	220 ILCS 5/ Public Utilities Act. Electric Service Customer Choice And Rate Relief Law of 1997. This legislation provides an example of exit fee provisions that encourage CHP.	http://www.ilga.gov/legislation/ilcs/ilcs4.asp?DocName=022000050HArt%2E+XVI&ActID=1277&ChapAct=220%26nbsp%3BILCS%26nbsp%3B5%2F&ChapterID=23&ChapterName=UTILITIES&SectionID=21314&SeqStart=40500&SeqEnd=45100&ActName=Public+Utilities+Act%2E
Massachusetts	220 CMR 11.00: Rules Governing the Restructuring of the Electric Industry. This legislation provides an example of exit fee provisions that encourage CHP.	http://www.magnet.state.ma.us/dpu/restruct/96-100/cmr11-2.pdf

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Evans, P.B. 2005. Optimal Portfolio Methodology for Assessing Distributed Energy Resources Benefits for the Energyenet. CEC, PIER Energy-Related Environmental Research. CEC-500-2005-061-D.	http://www.energy.ca.gov/2005publications/CEC-500-2005-061/CEC-500-2005-061-D.pdf