



CBO PAPER

**ELECTRIC UTILITIES:
DEREGULATION AND STRANDED
COSTS**

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PREFACE

Stranded costs, the potential losses to electric power utilities as their industry is deregulated, play an important role in the debate about restructuring the industry. Various electricity restructuring bills have been introduced into the House and Senate, but the questions of whether and how to compensate utilities for stranded costs remain a contentious and uncertain factor in the debate about restructuring.

This Congressional Budget Office (CBO) paper, prepared at the request of the House Committee on Commerce, provides a primer on the subject of stranded costs. It examines the economic implications of compensating utilities for such costs and discusses various actions that states and the Federal Energy Regulatory Commission have taken to address the issue. It also reviews various options for compensation and helps put possible federal actions into context. In accordance with CBO's mandate to provide objective, impartial analysis, this paper contains no recommendations.

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SUMMARY AND INTRODUCTION

Deregulating the retail market for electricity—generally referred to as restructuring the industry—has the potential to cut the prices that consumers pay for power. If prices drop, consumers gain. At the same time, however, many utilities lose. In traditionally regulated markets, utilities have been protected: they have had a monopoly in their area of service, and regulators have set prices high enough for utilities to recover their costs and earn a reasonable rate of return. Restructuring would remove that protection and introduce competition into the market. As a result, analysts believe, electricity prices would fall in many parts of the country. Those falling prices would erode the value of utilities' assets, leaving some of their costs unrecoverable, or "stranded." The total amount of stranded costs could be large—more than \$100 billion nationwide, according to many estimates.

Should utilities be compensated for stranded costs? Most utilities think so, but many consumer groups disagree. Utilities argue that they have been serving the public interest under a particular regulatory regime, and they should not have to absorb the costs of moving to a new set of rules. Among those costs could be losses on investments that utilities made in the public interest but would not have made in an unregulated market. Some of those investments came at the behest of regulators or were directed by the state or federal government, such as contracts to buy power from alternative suppliers at high prices. Utilities had more discretion over other investments, such as nuclear power plants; arguments for reimbursement of those losses are not as compelling.

Some opponents of compensation say it is unnecessary (because utilities have been generously rewarded in the past) and would discourage or delay the benefits of competition from reaching consumers. Further, they argue, restructuring has been in the works for a long time, so utility companies should be prepared for it. Moreover, other industries have experienced deregulation and survived.

Federal legislators are grappling with the issue of what role, if any, the federal government should play in determining whether utilities are reimbursed for stranded costs. To date, most of the actions about restructuring and stranded costs have occurred at the state level. The federal government faces a wide range of options. At one extreme, it could leave the issue entirely to the states, which have jurisdiction over regulating retail power sales. At the other extreme, the Congress could make rules about who should pay for stranded costs and what that payment should be (although in that case, the federal government's jurisdiction would be subject to legal dispute). In between those approaches, the Congress could pass legislation recommending guidelines but leave state lawmakers and regulators to carry out those guidelines.

Congressional discussions of stranded costs have run the gamut of those options. So far, however, no bills have been introduced that would impose specific mechanisms for paying compensation or raising the money to do so, although one

bill would prohibit compensation. Strictly speaking, federal action on stranded costs may not be necessary, but the issue is holding up moves toward deregulation in many states, and federal action could break some of the legislative and bureaucratic logjams.

Regardless of which level of government deals with stranded costs, the issue will mostly revolve around questions of fairness. Possible economic effects of compensating utilities are also a concern, but the economic arguments for and against compensation are not strongly supported. Nevertheless, how the funds for compensation payments are raised and how those payments are made to utilities have some economic implications.

Raising funds through a fee based on current use of electricity—the method of choice of most states that have acted—is worse than some alternatives but better than others from the perspective of economic efficiency. A fee based on historical power use would be preferable because the price paid for electricity would be closer to its actual cost. Such a fee would be an unavoidable lump sum that would have a smaller distorting effect on electricity use than a fee on current usage. However, a fee on current usage would probably be more efficient than a fee levied only on those customers who left their traditional utility to purchase power from a new entrant in the market. That approach has been discussed in several states and is being used in Michigan. Charging only departing customers may leave a tilted playing field in the market for power and delay the benefits of competition.

Similarly, the way utilities are compensated may create incentives that lead to inefficiencies in the electricity market. For example, compensation that is tied to the amount of power produced may cause inefficient generators to remain in operation that would otherwise shut down. A guaranteed recovery of stranded costs may distort utilities' incentives to minimize such costs. (For example, utilities may find it cheaper to buy out some of their power-purchasing contracts than continue paying those contracts' above-market prices, but they may need an incentive to choose the cost-reducing strategy.) Moreover, utilities may use any up-front payments they receive for stranded costs for anticompetitive purposes, such as acquiring other power-generating facilities in the same market or advertising to create brand loyalty.

No matter what method is used and how much utilities are paid, however, such fees are transitional. Over the longer run, the efficiency of the electricity market and the benefits for customers and the economy—benefits that may include encouraging the introduction of new services and sending better signals for future investment decisions, as well as lowering electricity prices—will depend more on how free and competitive the market becomes.

In examining the issues of stranded costs and their recovery, this paper addresses three main questions:

- o What are stranded costs and where do they come from?
- o How can they be measured?
- o What are the pros and cons of making different groups—consumers, taxpayers, utilities, and their stockholders—pay some or all of the stranded costs?

The analysis evaluates various answers to the third question using the criteria of economic efficiency, fairness, and administrative ease. It finds that whether utilities are compensated for their stranded costs is more a question of fairness and politics than of economic efficiency.

This paper focuses on compensating the stranded costs of investor-owned utilities, which make up about three-quarters of the electricity-generating industry. Electricity is also produced by publicly owned, cooperatively owned, and federal power entities. Restructuring the electricity industry may have an impact on those entities if their consumers are also allowed to choose alternative suppliers. However, compensation of losses may be less important to those utilities because, in many cases, publicly owned and cooperative utilities are self-regulated. (Restructuring could have tax implications for those utilities—a subject that is beyond the scope of this analysis.)

WHAT ARE STRANDED COSTS?

Stranded costs can be defined as the decline in the value of electricity-generating assets due to restructuring of the industry. (Electric utilities also own assets for transmitting and distributing electricity, but distribution and transmission are not expected to be subject to deregulation. If they were deregulated, a similar analysis could apply.) Under deregulation, electricity prices are likely to fall more than production costs, thus lowering the earnings of utilities and the value of their assets. In some cases, the quantity of electricity a utility sells may also fall as competitors enter the formerly exclusive service areas enjoyed by regulated utilities.

Sources of Stranded Costs

In traditional regulated markets, utilities receive exclusive rights to sell power to retail customers in particular areas at prices set by regulators. Utilities typically operate a distribution network, delivering electricity that they generate themselves or buy wholesale from other generators to homes and businesses. The first step in the deregulation process was to open up the wholesale market. (For more details of the regulatory history of the wholesale and retail markets for electricity, see Box 1.)

BOX 1.
REGULATION OF THE WHOLESALE AND RETAIL MARKETS FOR ELECTRICITY

Current efforts to restructure the electricity industry focus on the retail market (sales to final consumers) and aim to give buyers a greater choice of suppliers. The wholesale market (sales for resale) already involves choice because the utilities that supply power to consumers may buy electricity from a variety of sources. The wholesale and retail markets for electricity have different histories of regulation.

Wholesale Markets: Federal Regulation

The Federal Power Act of 1920, as amended in 1935, was the first attempt to bring the interstate features of the electric power industry under federal regulation. The argument for a federal role emerged with the expansion of local power markets and the beginnings of power sales across state lines. Specifically, the act empowered the Federal Energy Regulatory Commission or FERC (formerly the Federal Power Commission) to regulate the transmission of electricity in interstate commerce and the wholesale marketing of electricity by businesses active in interstate commerce. FERC's role extends to approving all mergers involving interstate utilities. By virtue of their dominance in interstate and wholesale transactions, most investor-owned utilities are under federal control. Also, because virtually all utilities (except those in Texas) are connected to large power grids that encompass many states, FERC has decided that wholesale transactions in all states but Texas are interstate commerce and, hence, subject to its jurisdiction.

FERC has primary responsibility for overseeing wholesale markets, but other federal agencies are also involved. The Securities and Exchange Commission approves acquisitions and divestitures for investor-owned utilities that the government considers public-utility holding companies. Such holding companies are corporations formed mainly for the purpose of owning and supervising the management of subsidiary corporations by owning stock in them. (Despite their name, public utilities are private companies that issue stock to the general public. They should not be confused with publicly owned utilities, which are quasi-governmental entities.)

Retail Markets: Local Regulation

The Federal Power Act left states responsible for regulating facilities that generate electricity, transmission of electricity within state boundaries, and local distribution. The principal regulator at the state level is the state public utility commission (PUC).

A charter from a PUC typically grants a utility—whether private or public—limited protection from competition within its service area. In return, the utility is obligated to provide reliable power to all customers in that area and to submit to state or local regulation of its retail prices. That service obligation also means the utility must add or acquire capacity to meet projected demand. Regulation of prices typically means PUC approval of the utility's rate schedules to ensure that they cover only allowable operating and capital costs, as well as approval for major construction projects and for capital acquisitions and divestitures.

Although the states have regulated investor-owned utilities, not all have actively regulated the publicly owned utilities in their jurisdiction, deferring in many instances to those utilities themselves (much as the federal power agencies are self-regulated) or to local power authorities. All 50 states have PUCs, but only 22 have some authority to regulate the prices of publicly owned utilities in their jurisdiction.¹ And of those 22, only seven have full authority to regulate both retail and (for intrastate sales) wholesale prices.

1. Department of Energy, Energy Information Administration, *Financial Statistics of Major U.S. Publicly Owned Electric Utilities, 1994*, DOE/EIA-0437(94)/2 (December 1995), Appendix D.

Many wholesale markets are now subject to "light-handed regulation" in which prices reflect market conditions rather than being set by regulators. Utilities are free to buy and sell power among themselves, from marketers, or from independent generators at prices that reflect conditions of supply and demand. Access to transmission lines has also been opened up to get the benefits of a competitive wholesale market.

The next step in the deregulation process—the so-called industry restructuring—is to introduce more competition at the retail level. Under typical concepts of restructuring, consumers would be able to choose among various electricity suppliers. The price consumers paid for distribution services would still be regulated, but the price they paid for the actual power would not be. Competition among power generators would cause those prices to reflect supply and demand.

Under regulation, by contrast, prices are based on the costs incurred by utilities rather than market forces. Regulators set electricity rates to recover allowed accounting costs (such as utilities' operating costs and the cost of repaying investments) over a period of time and to give utilities a reasonable rate of return. As utilities move to a restructured environment in which market forces play a major role in determining prices, prices will more closely reflect economic, not accounting, costs. That will create windfall gains or losses for some of the owners of electricity-generating assets. Utilities that make windfall profits (negative stranded costs) are likely to be ones that own highly depreciated generating plants or low-cost hydroelectric facilities, which may be able to charge higher market prices than they could under regulation. For utilities that experience windfall losses from deregulation, those losses could come from several sources.

Uneconomical Plants. Regulation sometimes allowed the cost of assets such as uncompleted nuclear power plants to be reflected in electricity rates. State public utility commissions had different rules regarding those assets and also have different rules about recovering their cost. Some state regulators have continued to allow utilities to recover the cost of those facilities, whereas others have not. In a restructured industry, plants not producing power would bring in no revenue. Uncompleted (and essentially abandoned) nuclear facilities would have only a salvage value. Moreover, some completed plants that are now in use will no longer be economical in a deregulated market.

Lower Prices. Even in states where regulation continues, electricity prices have been dropping recently. One reason is the aftermath of the Public Utility Regulatory Policies Act of 1978 (PURPA), which led many utilities to enter high-priced contracts with other electricity suppliers. Those contracts are now expiring, and state commissions are not requiring such high prices to be paid for new contracts. Another reason is that natural gas is substantially cheaper than it was in the 1970s and early 1980s because of changes in how it is regulated and

transported. The development of the combined-cycle gas turbine, which reuses waste heat, has also cut the cost of generating electricity from natural gas. As a result of those changes, utilities have increased their use of natural gas to produce electricity.

Electricity prices are expected to fall even further in a competitive market for three reasons. First, competition may create incentives to produce electricity at the lowest possible cost—incentives that are dampened under traditional regulation. Traditionally, when electricity prices are based on utilities' actual expenditures, utilities have little reason to control costs because any cost reductions will be passed on to consumers. In addition, when regulators allow utilities to earn a specified rate of return on capital expenditures, utilities have an incentive to invest in capital-intensive facilities (and perhaps "gold-plate" their facilities).¹ A competitive market would allow utility owners to reap more of the benefits of lower costs and, thus, would give them more reason to minimize costs.

Second, competition should give electricity suppliers an incentive to provide new services to consumers. Under traditional regulation, utilities generally provided all residential and commercial customers with the same product: reliable electricity at a fairly high, but uniform, price. Under competition, suppliers will have incentives to offer a greater variety of electricity services—with different prices and different degrees of reliability, depending on what the customer wants or needs.

Third, in a competitive regime in which cost recovery is not guaranteed, utilities will have more reason to invest in new, lower-cost technologies rather than continue to use higher-cost facilities that have already been built. Technological changes, such as the aforementioned invention of the combined-cycle gas turbine, have already reduced the cost of electricity generation. But the full benefits of technological and regulatory changes may not be realized if utilities continue to use their current generating facilities.

Technological changes have not only made lower electricity prices possible but also opened up the generation market to competitors. Combined-cycle gas turbine plants have proved to be economical on a much smaller scale than the nuclear and coal generation plants that dominate the U.S. electricity industry. Thus, the number of generating firms sustainable in the market is substantially larger.

Lower Demand. In addition to lower prices, some utilities may face declining demand for their electricity under deregulation. Although (at least for now) power distribution will still be done by the traditional utility in an area, consumers will be free to purchase electricity from any supplier. Consequently, utilities are apt to lose

1. Harvey Averch and Leland Johnson, "Behavior of the Firm Under Regulatory Constraint," *American Economic Review* (December 1962), pp. 1052-1069.

some of their customers to other power companies, such as independent generators or marketers.

Categories of Stranded Costs

Many researchers and state public utility commissions (PUCs) have identified separate categories of stranded costs. Ultimately, costs become stranded because the price of electricity or the quantity marketed drops, but the reasons that utilities incur those costs differ in ways that may affect arguments for or against compensation. Stranded costs fall into five main categories:

- o Unrecoverable costs of generation-related assets;
- o Long-term contracts for power or fuel that would be money losers with lower market prices for power;
- o “Regulatory assets,” such as deferred income tax liabilities, that regulators would have eventually allowed utilities to collect but that would not generate returns in a competitive market;
- o Capitalized investments in some social programs that were made at the direction of a PUC and that could not be recovered under competition; and
- o Employment transition costs, which are not really stranded costs but like them are an expense of moving to a more competitive market and are something for which utilities want compensation.

The first three categories constitute the bulk of stranded costs. Their relative importance varies by region, but overall each of those three makes up roughly one-third of estimated stranded costs.

Unrecoverable Costs of Generation-Related Assets. In regulated markets, the electricity rates that PUCs approve allow utilities to recover investments in generating facilities and earn a fair return on those investments. In a competitive market, if electricity prices are lower than the level necessary to repay the investments and provide a fair return, and if the assets cannot be sold for use elsewhere, those costs will be stranded. Many utilities argue that compensation is justified because the investments were usually made with the approval of PUCs and with the understanding that rates would be set so as to reward utilities for making those investments.

Lower competitive prices could cause some generating plants to shut down. Plants with variable costs (costs for fuel and operations and maintenance) that

exceed the expected market price of electricity are candidates for closure. The actual decision to shut a plant is often complicated, being affected by long-term contracts and other costs of closing (see Box 2 for details). If a plant is shut down, its stranded costs can be measured as the unrecovered capital costs—known as the “net plant in service.” Some analysts would add to that figure the capitalized value of an expected return on the investment.

A plant with variable costs that are less than the new market price will still make money for its owner (though in some cases less than under regulation) and thus will probably remain in operation. The new market value of that plant can be estimated by discounting its expected future stream of net returns. If that estimated market value is less than the net plant in service, then some costs are stranded and utilities may argue for compensation.

Some generating plants might even bring in more to their owners under competition than under regulation. Such facilities include older plants whose costs have been fully recovered under the regulated environment. The asset value of such plants would rise with a competitive market, creating what might be described as a negative stranded cost. Estimates of total stranded costs should net out the value of those assets. (Also netted out should be the value of sulfur dioxide permits if the plants using them are shut down or sold.)²

Money-Losing Long-Term Contracts. Long-term contracts that might have made good business sense in a regulated environment or that might have served some public purpose may become net liabilities in a competitive market. Two examples that may result in stranded costs are contracts that require utilities to buy power from other generators and contracts to buy fuel.

The main type of contract in the first category involves utilities that agree to purchase power from so-called “qualifying facilities” under the Public Utility Regulatory Policies Act. PURPA was intended to bolster small power producers and reduce dependence on fossil fuels. Many PURPA contracts were made at relatively high prices, with the understanding that regulators would allow the costs to be passed on to consumers. Under competition, those contracts would become liabilities for utilities. In addition, utilities have long-term contracts at above-market prices with other utilities or with nonutility generators that would also become liabilities.

The situation with PURPA contracts differs among states because states had discretion in carrying out the law. PURPA only required them to draw up

2. Dallas Burtraw, “Cost Savings, Market Performance and Economic Benefits of the U.S. Acid Rain Program,” in S. Sorrell and J. Skea, eds., *Tradable Permits, Tradable Quotas and Joint Implementation* (Cheltenham, England: Edward Elgar Publishing, forthcoming).

BOX 2.
FACTORS THAT DETERMINE WHICH GENERATING PLANTS OPERATE
AND WHICH CLOSE

In theory, a company decides which of its plants to operate on the basis of whether a plant's average variable costs are less than the market price of what it produces. In electricity generation, the problem of deciding which plants to operate in the short run—the "unit commitment" problem—must take into account three facts: the amount of time and money required to start up and shut down plants differs by the type of fuel they use, fluctuations in the demand for electricity require that some plants run at low levels all the time in case of a sudden surge in demand, and constraints on the transmission of electricity require that some plants operate even if lower-priced suppliers exist elsewhere.

Some generating plants, such as natural gas turbines and many hydroelectric facilities, are easily shut down and started up. Others may take days to become operational. Also, because demand for electricity fluctuates hourly as well as daily—and because there may be unanticipated disruptions of supply—some units must remain on to produce only low levels of electricity, waiting for increases in demand to trigger the decision to increase production. Such units are called "spinning reserves." Other plants operate on a "must-run" basis because they are needed to maintain the integrity of the electricity grid. All of those factors make it difficult to calculate what a plant's average variable costs really are, complicating the decision about which plants to operate and which to close.

Some of the difficulty can be eliminated by unbundling different components of electricity production—such as spinning reserves—and selling them separately. That would provide an opportunity for such plants to cover their costs.¹ Those plants provide valuable products to the electricity market, even if they are rarely used.

1. Lester Baxter, *Different Approaches to Estimating Transition Costs in the Electric-Utility Industry*, ORNL/CON-423 (Oak Ridge, Tenn.: Oak Ridge National Laboratory, October 1995).

electricity-purchase contracts at a rate that was no greater than the utility's "incremental cost" (the cost of producing that electricity itself or purchasing it from another source). The definition of incremental cost was left to the states to determine.³ California and some other states estimated incremental costs to be far greater than today's electricity-generation prices. Some states forecast those prices on the basis of expected oil prices as high as \$100 per barrel (whereas the average price of oil in 1998 is less than \$15 per barrel). Other states, such as Maine and Colorado, set the purchase price equal to the average operation and maintenance costs of a specific nuclear generator. Still other states required a bidding mechanism to determine the price—a result that led to fewer above-market contracts. Because of those differences, the share of total estimated stranded costs accounted for by PURPA contracts differs substantially among states.

3. The Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 824a-3, 92 Stat. 3144.

Utilities' long-term contracts to buy fuel could result in similar stranded costs. Under a regulated regime, what might turn out to be above-market fuel costs quite often would automatically be shifted onto ratepayers. Many states (38 out of 50) have an automatic mechanism that allows for such an adjustment for both fuel costs and power purchases.⁴ The contracts that are now at above-market prices are primarily for coal, although some utilities have above-market natural gas contracts.⁵ Under competition, utilities cannot automatically pass on those costs to ratepayers, so such contracts become liabilities.

Unrecoverable Regulatory Assets. Regulatory assets are unique to regulated entities. In the electric power industry, a regulatory asset is essentially a promise from a public utility commission to let a regulated utility recover a cost it has already incurred by charging higher rates in the future than it would otherwise. If electricity rates are no longer regulated, the ability to recover that money may be impaired, and the regulatory asset becomes worthless.

Electric utilities have a special accounting rule, commonly known as Statement 71, that is not available to nonregulated entities.⁶ If a regulator does not allow a utility to record costs in the accounting period in which they are incurred but expects to allow the utility to recover those deferred costs in some future period, Statement 71 lets the utility capitalize the expenses as regulatory assets. The Federal Accounting Standards Board permits utilities to create regulatory assets only if three conditions are met: the rates were set by a third-party regulator, they were designed to recover costs, and there was a reasonable assumption that the costs would be collected from customers, given anticipated changes in demand and levels of competition during the recovery period. For example, regulatory assets that the California Public Service Commission considers as stranded costs include deferred operating expenses, deferred taxes, unamortized debt expenses, and costs associated with issuing or reacquiring debt.

To further complicate the relationship between accounting and regulatory treatment in setting rates, examples exist of "unrecorded" regulatory assets. They represent promises by PUCs for future recovery of expenses even though accounting rules do not recognize the expenses as regulatory assets. For example, the Arizona Corporation Commission required Tucson Electric Power Company to defer various expenses related to its Springerville Generating Station because the utility had excess capacity. But accounting rules denied the recognition of those

4. National Association of Regulatory Utility Commissioners, *Utility Regulatory Policy in the United States and Canada: Compilation 1995-1996* (Washington, D.C.: NARUC, 1996), Table 205, pp. 457-458.

5. Resource Data International, *Power Markets in the U.S.* (Boulder, Colo.: RDI, 1996), p. 12.

6. Financial Accounting Standards Board, "Accounting for the Effects of Certain Types of Regulation," Statement of Financial Accounting Standard No. 71 (December 1982).

costs as a regulatory asset, although the commission expected that the utility would be allowed to recover them in the future.

Estimates of stranded costs, then, need to consider both recorded and unrecorded regulatory assets. Also, regulators may have allowed utilities to collect expenses through rates before the expenses were actually incurred. Those pre-collected expenses should be subtracted from stranded costs.

Unrecoverable Investments in Social Programs. Another category of costs that may not be recovered in a competitive market is costs incurred for social programs—such as demand-side management (which includes efforts to encourage energy conservation), pollution control, provision of universal service, and assistance for low-income customers. State regulators may include as stranded costs past spending on such programs that has not yet been recovered. The costs of some of those programs, notably demand-side management (DSM) programs, are amortized over time. The balance remaining at the time that the retail electricity market was deregulated would not be recovered in a competitive market. Some social programs, however, would not entail any stranded costs because they involve not capital expenditures but current costs, which are recovered at essentially the same time they are incurred.

In 32 out of 50 states, public utility commissions let utilities capitalize DSM expenses and thus earn a return on them.⁷ The process of capitalizing the assets works as follows: say the utility spends \$50 million in a given year on providing rebates to customers who buy high-efficiency air conditioners and energy-efficient light bulbs. Rather than including all \$50 million as costs in that year, the utility sets up a fund with the \$50 million and depreciates the amount over a given period of time (say, five years). In the first year, the utility collects \$10 million from ratepayers and earns a return on the average undepreciated portion. PUCs allow utilities to earn a return on such activities to encourage utilities to engage in them. Since those costs are not part of generating power, the market price for electricity will not reflect spending on DSM programs, and utilities will not be able to recover unexpensed DSM costs.

In addition, utilities are often compensated for lost revenues caused by conservation or load-management activities. For example, by encouraging customers to buy high-efficiency air conditioners, a utility will be selling less electricity to those customers. PUCs generally permit utilities to be compensated for such lost revenues the next time rates are set. Since rates for electricity generation will no longer be set once retail choice is implemented, the utility will not be compensated for revenues it loses between the last rate setting and the beginning of retail choice.

7. National Association of Regulatory Utility Commissioners, *Utility Regulatory Policy in the United States and Canada*, Table 235, pp. 510-511.

Employment Transition Costs. The final category of stranded costs is employee-related expenses prompted by restructuring, such as the costs of offering early retirement or job training. Unlike other types of stranded costs, employment costs are not capital costs but changes in utilities' operating costs. Like other stranded costs, however, they may represent payments made because of deregulation. Legislators or regulators in California, Michigan, New Jersey, Maine, Pennsylvania, and Massachusetts have included such expenditures as stranded costs that can be recovered. Arizona is also considering including them. Employment transition costs are small, however, compared with the unrecoverable costs of generation-related assets and long-term purchasing contracts.

HOW ARE STRANDED COSTS MEASURED?

Stranded costs are not easy to measure, and analysts have used or considered several methods. Those methods differ by whether they measure stranded costs before or after restructuring takes place, whether they are based on analysts' estimates or on actual market valuations of assets (which might only be determined when companies sell those assets), and whether they look at a firm's individual assets or take a more aggregate, "top-down" approach.

Deciding how to measure stranded costs involves more than just seeking an accurate figure and avoiding methods that would interfere with efficient actions by power companies. Two other considerations also affect the decision. First, measurement methods may be tied to policies about how to compensate utilities. For instance, if policymakers decide that utilities should receive a single, up-front payment or a fixed amount paid over time, then the method will have to be one that can be used before restructuring takes place (an *ex ante* estimate). If, however, policymakers want to see how restructuring turns out before deciding how much to pay, only later (or *ex post*) methods of estimating make sense.

Second, other decisions about how to restructure the industry affect which measurement methods are feasible. If, for example, policymakers decide that vertically integrated utilities (those that are involved in producing, transmitting, and distributing electricity) must divest themselves of their generating assets to avoid excessive market power, then one way to estimate stranded costs is to take the difference between the book value of an asset and its selling price. California and Massachusetts required such divestiture and, at least partly, based estimates of stranded costs on market prices. Also, Arizona has linked divestiture of generating assets with compensation for stranded costs.⁸

8. Arizona Corporation Commission, *Decision on Electric Competition*, Docket No. RE-00000C-94-0165, Decision No. 60977.9 (June 22, 1998), p. 9 (available at <http://www.cc.state.az.us/utility/electric/decision.htm>).

The main methods of measuring stranded costs are the following:

- o Administrative *ex ante* estimates, in which the analyst either estimates the present value of the difference between the utility's expected revenues under continued regulation and under competition (a top-down method) or estimates the value of individual assets under competition and then subtracts the portion not yet recovered (a bottom-up method). The Federal Energy Regulatory Commission (FERC) has used a top-down, administrative *ex ante* method to estimate wholesale stranded costs (see Box 3). Such estimates require uncertain forecasts of electricity prices under assumptions about both competition and regulation. They must also account for special factors, or "hidden values," that can increase or decrease the actual worth of the company or the generating facility being measured.⁹ Special factors include the value of the site if the generator is repowered or refurbished, any special value the site might have because of its location in the electrical grid, and the site's value for nongeneration uses.¹⁰
- o Market valuation of assets, such as with the divestiture of assets done in California and Massachusetts or a "reverse" auction to sell above-market PURPA or other power-supply contracts. In such an auction, the winner is the party willing to take the least amount of money to accept the terms of the contract. A pipeline company suggested using that method with contracts to supply natural gas as part of a settlement under FERC Order No. 636.¹¹
- o An *ex post* measurement, such as the difference between the actual market price and the expected regulated price over time. An advantage of *ex post* over *ex ante* methods is that they use actual market prices—although, for comparative purposes, analysts still need to estimate what would have happened if regulation had continued. Another advantage is that a good *ex post* measurement does not affect the actions of utilities.

9. New Hampshire Public Utilities Commission, *Restructuring New Hampshire's Electric Utility Industry: Final Plan*, February 28, 1997 (available at <http://www.state.nh.us/puc/plan/fv.html>).

10. As an example of refurbishing, a utility-owned, oil-fired generator in Massachusetts was auctioned off recently, and the new owner is planning to mothball the old facility and build a new gas-fired generator on the site. See Ronald Rosenberg, "Cleaner Power Plant Is Proposed for Everett," *Boston Globe*, July 16, 1998.

11. Northern Natural Gas Company settlement, approved on July 16, 1993 (Federal Energy Regulatory Commission Docket No. R5-92-8).

BOX 3.

THE FEDERAL ENERGY REGULATORY COMMISSION AND STRANDED COSTS

The Federal Energy Regulatory Commission (FERC), which has jurisdiction over wholesale electricity sales, issued a ruling in May 1996 that certain utilities could recover 100 percent of their wholesale stranded costs. That ruling (Order No. 888) applies to so-called "requirements" customers, which are generally municipally or cooperatively owned utilities that contract with another utility for some or all of their power. If such utilities own some generating facilities, they are referred to as partial requirements customers, and if they have no generating facilities, they are known as full requirements customers. Such customers do not specify an exact amount of power they will purchase from a contracting utility; instead, that utility agrees to provide all of the power the requirements customer needs (or all of the power over a certain amount).

The obligation to serve a wholesale requirements customer is similar to the traditional obligation that a utility has with retail customers. FERC limited the scope of its ruling on stranded costs to full or partial requirements customers because, on the wholesale level, utilities could argue that generating facilities were built to serve those customers. Other wholesale transactions made between utilities were more likely to be sales of excess generating capacity or exchanges of power in which the selling utility did not invest in power generation simply to serve the contract.

Under Order No. 888, stranded costs are equal to the discounted value of the expected revenues in the absence of the order minus the value of the expected contracted amount in the open market. FERC has allowed utilities to supply that value. However, the lower bound of that administratively determined value (which determines the upper bound of stranded costs) is the amount that the requirements customer is paying its new supplier. That amount is determined *ex ante*, without any later adjustment.

In addition, FERC extended the definition of stranded costs to go beyond a contractually implied amount. In other words, a utility may claim stranded costs arising from revenues that were lost after the contract had expired—if the utility can show a reasonable expectation that in the absence of Order No. 888 it would have continued to serve the requirements customer.

FERC's formulation of stranded costs compensates utilities for past inefficiency. A utility is reimbursed not just for unrecovered fixed costs but also for higher variable costs than the market average. In effect, however, such an overcompensation scheme simply represents a transfer from ratepayers to the utility. The utility's incentive to minimize costs is not dampened, so there is no effect on efficiency.

FERC's method of measuring stranded costs also includes a market-valuation component. Requirements customers who leave their traditional utility have the option of marketing their contract themselves to see whether they can find a replacement customer who is willing to pay a higher price for it than the utility estimates.

In contrast, if plants need to remain in operation to receive compensation for stranded costs, utilities may have an incentive to keep uneconomic plants operational.

- o The Goldwater Institute's measure (a specialized type of *ex post* method).¹² It involves splitting the utility's outstanding stock before restructuring into two parts: an A stock, which is the usual voting stock, and a B stock, which is the right to receive compensation for stranded costs. The two types of stock would then be traded separately. Stranded costs—which are paid to holders of B stock—are calculated as the net book value before restructuring minus the average market value of A stock at some fixed period of time after restructuring. Stranded costs would only be positive if stock prices fell below book value. Whereas the stock price before the split would reflect investors' expectations of stranded-cost compensation, the value of A stock should reflect only the value of the company as a going concern. That is because compensation for stranded costs is not paid to the company but directly to holders of B stock. So far, no state has used the Goldwater Institute's method to value stranded costs.

All methods of measuring stranded costs have their advantages and disadvantages. Since a great deal of money is involved in some states, the decision about which method to use can become contentious. At the same time, however, regulators can use certain techniques to try to minimize stranded costs (see Box 4).

CURRENT ESTIMATES OF STRANDED COSTS

Estimates of utilities' total stranded costs nationwide have ranged from \$10 billion to \$500 billion, although most estimates fall between \$100 billion and \$200 billion.¹³ Various financial houses, government agencies, and consulting firms have produced independent estimates of stranded costs, mainly looking at individual states. Three independent estimates that look at such costs nationwide come from Moody's Investors Service, Resource Data International (RDI), and the Oak Ridge National Laboratory. They are all administrative *ex ante* estimates.

Those three sources give remarkably similar numbers for utilities' total exposure to stranded costs (see Table 1). Oak Ridge's estimate is the lowest

12. Michael K. Block, Robert Franciosi, and Melinda Ogle, *The ABC's of Stranded Costs* (Phoenix, Ariz.: Goldwater Institute, no date).

13. For a survey, see Department of Energy, Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update* (December 1996).

BOX 4.
REDUCING THE MAGNITUDE OF STRANDED COSTS

In places where deregulation is pending, regulators have used or plan to use various techniques to try to make stranded costs smaller. Those techniques include encouraging utilities to decrease their costs or increase their revenues.

In some cases, regulators give utilities incentives to lower their costs, particularly from above-market contracts for power or fuel. For example, utilities are encouraged to buy out those contracts by letting shareholders keep some of the savings from the buyout. Contract holders are willing to be bought out of such contracts as long as they receive the present discounted value of their profits from the life of the contract. If the contract holder is very inefficient, ratepayers could be made better off by such buyouts. For instance, if the contract price of power is 10 cents per kilowatt-hour (kWh) and the market price of power is 4 cents per kWh, then ratepayers are better off by having the utility buy out the contract if the contract holder has costs of 4 cents per kWh or higher.

Evidence from the electric power industry shows that such buyouts are occurring and have accelerated in recent years. In March 1996, 45 buyouts had been completed. By July 1997, that number had risen to 110.¹

Besides getting them to lower costs, regulators can encourage utilities to increase their revenues by marketing unused capacity. Utilities have begun selling power beyond their normal service areas and may be offering different prices to different customers to maximize revenues. Regulators can encourage those practices either by penalizing unused capacity by not allowing total recovery of stranded costs, or by allowing utilities to keep a portion of the additional revenues.

1. Edison Electric Institute, *Power Purchase Agreement Buy Out Experience and Merchant Power Projects: 1997 Status Report* (Washington, D.C.: Edison Electric Institute, 1997).

because it nets out taxes (assuming a federal tax rate of 35 percent) if those losses are written off.¹⁴ The three sources also give similar estimates of stranded costs by region. All three report that utilities in New England and the West face the highest stranded costs.

The RDI study provides estimates for different categories of stranded costs. According to that study, net generating assets account for 36 percent of stranded costs on a national basis, regulatory assets make up 33 percent, and power-purchase contracts make up 30 percent. Two other categories, past outlays for social programs and employee transition costs, were not measured.

14. Lester Baxter and Eric Hirst, *Estimating Potential Stranded Commitments for U.S. Investor-Owned Electric Utilities*, ORNL/CON-406 (Oak Ridge, Tenn.: Oak Ridge National Laboratory, January 1995).

TABLE 1. SELECTED ESTIMATES OF TOTAL STRANDED COSTS

Source of Estimate	Total Stranded Costs (Billions of dollars) ^a	Assumptions
Oak Ridge National Laboratory ^b	72-104	Net of taxes
Resource Data International ^c	122	Net of above-market generating assets and low-cost power from federal projects
Moody's Investors Service ^d	136	Included 116 utilities, representing more than 80 percent of assets of investor-owned utilities

SOURCE: Congressional Budget Office based on the studies cited below.

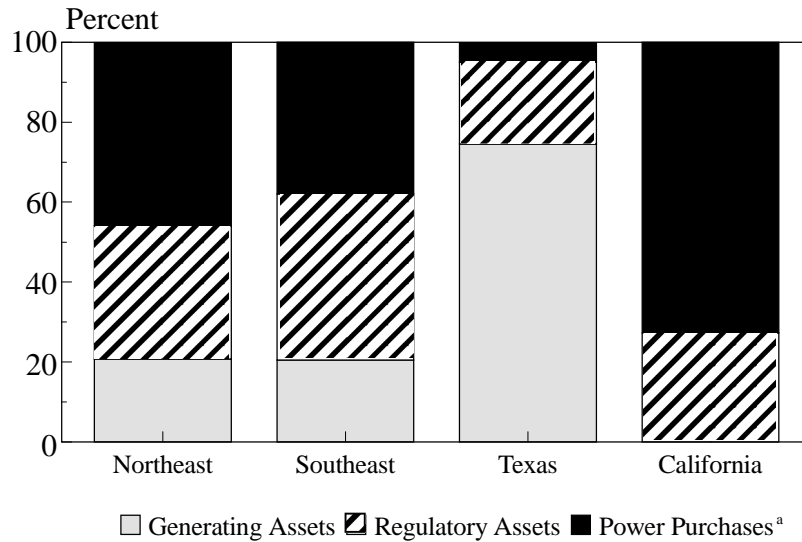
- a. For investor-owned utilities only. The figure shown is the most probable number or range in each study.
- b. Lester Baxter and Eric Hirst, *Estimating Potential Stranded Commitments for U.S. Investor-Owned Electric Utilities*, ORNL/CON-406 (Oak Ridge, Tenn.: Oak Ridge National Laboratory, January 1995).
- c. Resource Data International, *Power Markets in the U.S.* (Boulder, Colo.: RDI, 1996).
- d. A. Hackett, J. Cohen, and S. Abbott, *Moody's Calculates Little Change in Potential Stranded Investments* (New York: Moody's Investors Service, 1996).

Neither Moody's nor RDI's estimates take into account the fact that electricity, especially that produced by spinning reserves and must-run generators (explained in Box 2 on page 9), will have different prices at different times. Their estimates of electricity prices are also sensitive to assumptions about such things as where and when constraints may occur on the electricity grid and the relative quantities of electricity consumed in peak and off-peak hours. The assumptions they used overstate total stranded costs because higher prices at peak hours will benefit some generators and reduce stranded costs.¹⁵

Although uneconomic generating assets, regulatory assets, and long-term power-purchase contracts contribute almost equally to stranded costs nationwide, large regional differences are visible. For example, California's stranded costs

15. Lester Baxter, *Different Approaches to Estimating Transition Costs in the Electric-Utility Industry*, ORNL/CON-423 (Oak Ridge, Tenn.: Oak Ridge National Laboratory, October 1995).

FIGURE 1. CATEGORIES OF STRANDED COSTS BY REGION



SOURCE: Congressional Budget Office based on data from Resource Data International.

NOTE: These numbers reflect net stranded costs after subtracting the costs of below-market generation facilities or power purchases.

a. Includes contracts mandated by the Public Utilities Regulatory Policies Act of 1978 (PURPA) as well as other power purchases by utilities.

result largely from high-cost PURPA contracts for purchasing power, whereas in Texas the bulk of stranded costs come from generation-related assets (see Figure 1).¹⁶

THE PROS AND CONS OF MAKING DIFFERENT GROUPS PAY FOR STRANDED COSTS

Stranded costs are an issue because owners and creditors of generating utilities believe they will be unfairly burdened with large costs in the transition to a less regulated retail market for electricity. As a result, they want compensation. That compensation could come from fees on users of electricity or payments from the federal government that take the form of direct outlays or new tax breaks.

16. Resource Data International, *Power Markets in the U.S.*

The debate about stranded costs raises the following policy questions:

- o Should utilities be compensated and, if so, to what extent?
- o If compensation funds are collected from ratepayers, how will that be done?
- o If compensation funds are distributed to utilities, how will that occur?

The various answers to those questions can be judged on the basis of their implications for economic efficiency and fairness. From the perspective of efficiency, for example, one policy option would be preferable to another if it introduced fewer distortions into the economy. But whereas efficiency can be determined by economic analysis, fairness is a more subjective criterion. Nevertheless, identifying potential winners and losers from an option can aid in making policy decisions. Another factor that sometimes plays a role is administrative cost or feasibility. A policy may look promising on paper but be impossible to implement.

Should Utilities Be Compensated?

If restructuring occurred with no provision for compensation, utilities would bear the weight of stranded costs. The tax treatment of those costs would cushion some of the blow, so part of that burden would be shared with the federal Treasury (and federal taxpayers). The question facing policymakers is whether utilities should receive some type of payment as restructuring occurs.

Efficiency. Many economists would argue that if utilities received compensation without regard to their current and future actions, the effect on the production, cost, and price of power would be minimal. Hence, there would be little or no effect on efficiency. A utility would undoubtedly be better off with compensation than without it, but the operation of efficient plants should not be affected by whether compensation was paid.

Other economists, however, have argued that if utilities were denied full reimbursement of their stranded costs, investors would view the electricity market as very risky. Consequently, the cost of capital would rise for new investment, thus raising the future cost of electricity.¹⁷ That argument may be stronger for investments, such as PURPA contracts, that were specifically required by regulators.

17. A. Lawrence Kolbe and others, *Regulatory Risk: Economic Principles and Applications to Natural Gas Pipelines and Other Industries* (Boston, Mass.: Kluwer Academic Publishers, 1993).

Other analysts claim that recovery of stranded costs would slow the benefits of competition and keep electricity prices higher than otherwise. They claim that recovering stranded costs from ratepayers and taxpayers would reward utilities for making poor choices about electricity generation in the past and would not encourage them to make good choices in the future.¹⁸ Yet others suggest that utilities might use their compensation revenues for anticompetitive purposes, such as acquiring other generating facilities in the same market and advertising to create brand loyalty—all actions that could keep prices up.¹⁹

If compensation has little or no consequences for efficiency, then the decision about how much to pay will likewise have little or no effect on efficiency. Analysts who believe otherwise would argue that more compensation would have a greater effect (for better or worse) than less compensation.

Fairness. What is fair is really the dominant question in the debate about stranded costs. Arguments about fairness fall into four main categories. First, proponents of compensating utilities for stranded costs claim that a regulatory compact exists between the public utility commissions and the utilities under their jurisdiction. Under that compact, they say, the utilities provide universal electricity service to all customers in a specified area at a price determined by the state in exchange for guaranteed recovery of their costs. Proponents of compensation see restructuring as renegeing on that regulatory compact, which in their view is grounds for compensation. Others, however, believe that the regulatory compact requires only that utilities have a reasonable opportunity to recover their costs, not a guarantee.²⁰

Second, proponents of collecting compensation funds from ratepayers and taxpayers believe that if electricity restructuring does not allow recovery of stranded costs, it constitutes a legal "taking," which is prohibited by the Fifth Amendment of the Constitution.²¹ They argue that the loss in value of the utility's power-generation assets is the result of opening up the distribution wires to the utility's competitors. Therefore, the utility should be compensated for being required to provide retail access to its formerly captive electricity customers.

18. Scott Hempling, Kenneth Rose, and Robert Burns, *The Regulatory Treatment of Embedded Costs Exceeding Market Prices: Transition to a Competitive Electric Generation Market—A Briefing Document for State Commissions* (Columbus, Ohio: National Regulatory Research Institute, November 7, 1994); and Kenneth Rose, *An Economic and Legal Perspective on Electric Utility Transition Costs*, NRRRI 96-15 (Columbus, Ohio: National Regulatory Research Institute, 1996).

19. See, for example, IPALCO Enterprises, *The Securitization Swindle*, white paper (Washington, D.C.: IPALCO Enterprises, May 1997).

20. See, for example, Rose, *An Economic and Legal Perspective on Electric Utility Transition Costs*.

21. See, for example, J. Gregory Sidak and Daniel Spulber, *Deregulatory Takings and the Regulatory Contract* (Cambridge: Cambridge University Press, 1997), p. 4.

Third, some proponents of compensation claim that responsibility for many stranded costs rests with the state and federal governments. Because state implementation of federal laws—such as PURPA and the Power Plant and Industrial Fuel Use Act of 1978—led to higher costs, those costs should be reimbursed.

Fourth, the Administration has advocated reimbursement on the grounds that under regulation, utilities were precluded from earning high rates of return. For fairness reasons, the Administration concludes, utilities should also be exempt from earning abnormally low rates of return under competition.²² Opponents have argued that changes in regulation are not a new phenomenon and that the deregulation process has been a long one. Thus, utilities should not have expected to retain their monopoly franchise forever and should have adjusted their costs long before actual deregulation began.²³

How Should the Money Be Collected from Ratepayers?

If policymakers opt to compensate utilities for stranded costs using money collected from ratepayers, the choice of how to collect that money remains. Various states have used or proposed three mechanisms for collection:

- o A surcharge per kilowatt-hour (kWh) of electricity consumed,
- o A lump-sum surcharge on all customers, or
- o A lump-sum exit fee charged only to customers switching electricity suppliers.

Those mechanisms differ in their effect on the prices that consumers face and thus may have implications for economic efficiency. They also have different effects on various groups of consumers and thus raise questions of fairness. All of the fees in question, however, are transitional; they will be eliminated at the end of the cost-recovery period. Therefore, any consequences for efficiency will be temporary. All three mechanisms would impose surcharges on electricity buyers that they could not bypass—in other words, consumers could not switch among suppliers to avoid the surcharge.

22. *Economic Report of the President* (February 1996), pp. 187-188.

23. Irwin M. Stelzer, "What Happens When the Rules Are Changed and the Plug Is Pulled on Electric Utilities? The Positives and Negatives of Government Action," *American Enterprise* (November/December 1994), pp. 80-81.

Per-kWh Surcharge. This type of fee would be levied on a customer's current electricity consumption and would be fairly easy to collect. Consumers are already becoming accustomed to receiving bills with various types of charges. Under a restructured environment, they would be charged separately for the power they use and the services they receive from the distributing utility. A fee for stranded costs could easily be added.

A per-kWh surcharge would not need to be a uniform amount per kilowatt-hour or the same for all customers. Large customers could be charged more than small ones, for example, or residential customers more than industrial customers.

Such a surcharge may not rate highly, however, from the standpoint of economic efficiency. Like an excise tax, it would place a wedge between the cost of producing power and the price that consumers pay. Consumers would tend to buy less electricity, and the economy would lose some of the benefits of lower electricity prices during the period the surcharge was in effect. That loss would be larger the more responsive the consumer's use of electricity was to changes in price. Industrial customers are believed to be far more responsive to price changes than residential customers. Thus, efficiency losses could be reduced by allocating more than a proportional share of the fees for stranded costs to residential customers.

From a fairness perspective, charging fees on the basis of the amount of power consumed is appealing. People who use more electricity will eventually benefit more from the lower rates that restructuring promises, so charging them more during the transition makes sense to many observers.

Of the states that have decided on a mechanism for recovering stranded costs, most are using a per-kWh surcharge for all customers. Rhode Island (where retail choice in the electricity market began on January 1, 1998) has set a surcharge of 2.8 cents per kWh on all classes of customer. That rate will be recalculated after all of the utilities' generating assets have been auctioned off.²⁴ California has also proposed using a complicated type of per-unit surcharge (see Box 5 for details). In Arizona, regulators have recommended using either a per-kWh charge or a fixed fee independent of usage to recover stranded costs.²⁵ Since all customers would have to pay the surcharge, those customers who opted to produce their own power might have to pay a lump-sum fee instead of a per-kWh charge. (In California, such customers who had already planned to build generating facilities before December 1995 are exempt from paying the surcharge.)

24. Rhode Island Public Utilities Commission, *Summary of Major Provisions of the Rhode Island Utility Restructuring Act of 1996* (available at <http://www.ripuc.org/electric/billsum.htm>).

25. Arizona Corporation Commission, *Report of the Stranded Cost Working Group*, September 30, 1997 (available at <http://www.cc.state.az.us/working/stranded.htm>).

BOX 5.
CALIFORNIA'S MECHANISM FOR RECOVERING STRANDED COSTS

California began restructuring its electricity industry at the end of March 1998.¹ The state created a centralized market for electricity generation, called the Power Exchange, that sets the market price for electricity on the basis of bids that all utilities are required to submit to the exchange. As part of restructuring, utilities must also divest themselves of all power-generating assets that run on fossil fuels (although San Diego Gas & Electric is also selling off its share of the San Onofre Nuclear Generating Station).

Legislation passed by the state required a 10 percent reduction in electricity rates for residential and small commercial customers starting January 1, 1998. That 10 percent reduction was securitized through rate-reduction bonds. Therefore, the price that residential and small commercial customers will pay for electricity is equal to the price cap determined by the 10 percent rate reduction. The surcharge for stranded costs is the residual of that price cap after paying the Power Exchange's price; utilities' costs for distribution, transmission, metering, and billing; and charges for the rate-reduction bonds. Therefore, when the Power Exchange's price is high, the stranded-cost surcharge may end up being zero. The total amount of stranded costs that utilities will be allowed to recover will be determined by the California Public Utility Commission after fossil-fuel generating assets have been auctioned off.

1. For more information, see California Public Utilities Commission, *Electric Restructuring Page* (available at http://www.cpuc.ca.gov/electric_restructuring/er_home_page.htm).

Lump-Sum Surcharge. Instead of the type of fee described above, a surcharge could be totally independent of current electricity use. Such a charge would be added to a customer's power bill as a fixed amount (or lump sum) during the period the charge was in effect. That lump sum could vary by customer or class of customer. It could even be based on the customer's use of power during some fixed period in the past.

From an efficiency perspective, a lump-sum charge has the advantage of not affecting the per-kWh price that consumers face. Thus, it would be less likely than a charge on current use to cut electricity consumption and to delay the economic benefits of restructuring.

From a fairness perspective, a lump-sum surcharge (particularly one based on historical usage) would appeal to some observers because the charge would be levied on the customers in whose interest the stranded costs were incurred in the first place. And if the charge was allocated among types of customers in a similar way as a per-kWh charge, the amount paid by individual customers would probably not be very different under the two systems. There could be some exceptions, however, such as newly constructed industrial facilities.

No state has used a lump-sum surcharge, although, as mentioned above, Arizona is considering it.

Lump-Sum Surcharge Imposed Only on Departing Customers. An alternative to charging all customers—whether on the basis of current usage or a lump sum—is to charge only those consumers who opt to buy power from a generator other than their traditional utility. Such a charge would effectively encourage customers to stay with their traditional electricity supplier. Thus, competitors would have to undercut the traditional utility's price by more than the amount of the surcharge to attract business.

By constraining competition, this option would cause customers of the traditional utility to pay more for electricity than either of the other two options would. But because those customers would not be paying separate surcharges to cover stranded costs, the difference could be small.

Moreover, this type of surcharge would allow traditional utilities to maintain somewhat higher prices for electricity than would otherwise be the case while departing customers were subject to the fee. That would cut utilities' stranded costs.

From an efficiency perspective, a lump-sum surcharge on departing customers could rate lower than the other two options because it would protect traditional utilities from immediately facing competition. With a short and definite transition period, however, the economic costs of such protection could be small. Traditional utilities that were certain of facing competition in the future could not delay for too long in making efficiency improvements. But the lack of a level playing field for new entrants to the retail electricity market could delay the economic benefits of restructuring.

From a fairness perspective, this option might not look very different from the alternatives (depending on how their fees were structured). However, charging only departing customers would remove policymakers' discretion to assess different fees on different groups of customers, which they could do under the first two options. Thus, policymakers could not redistribute the burden of stranded costs in ways that they considered fairer.

Michigan is using this type of lump-sum surcharge on customers that switch power companies. In addition, such customers will have to pay a per-kWh surcharge. During the transition period (while retail competition is phased in slowly), the Michigan Public Service Commission will not set a fixed rate for that surcharge; instead, suppliers, marketers, or even customers will bid the amount of

per-kWh surcharge they are willing to pay.²⁶ Because of that policy, customers—even in the same customer class—may pay differing surcharge amounts during the interim period.

This option is also similar to one that the Federal Energy Regulatory Commission used to recover stranded costs in the transmission system for electricity (see Box 3 on page 14).

Other Alternatives. Other mechanisms that could be used to collect stranded costs are rate freezes or caps. Under those options, utilities would essentially charge higher prices for the components of the electricity market—distribution and transmission—that are still regulated. The surplus revenues would be given to utilities to compensate them for stranded costs. Of course, those higher prices would have a negative effect on economic efficiency.

How Should Payments Be Distributed to Utilities?

Like the various mechanisms for collecting funds from ratepayers, the method by which utilities are compensated for stranded costs may have implications for efficiency and fairness. In many states, legislators have allowed utilities to receive an up-front payment for some of their stranded costs through a process called securitization.

Securitization works as follows: state legislation authorizes utilities to receive the right to a stream of income from ratepayers. Utilities can turn over that right to a state infrastructure bank in exchange for a cash payment. The state infrastructure bank then issues bonds that are backed by that stream of income. Such bonds, which are exempt from state income tax (though not federal income tax), have generally received a triple-A rating from Moody's Investors Service.

Securitization can save ratepayers money. Because the bonds have a triple-A rating and are free from state tax, their interest rate is lower than the utility's cost of borrowing. The customer surcharge required to pay off the bonds is less than the charge that would be necessary to produce the same amount of money for the utility. The weaker the credit rating of the utility in question, the greater the potential savings from securitization.²⁷

26. Michigan Public Service Commission, *Michigan Electric Restructuring: A Chronology of Events*, July 1, 1998 (available at <http://ermisweb.cis.state.mi.us/mpsc/electric/restruct/history.htm>).

27. Fitch Research Report, *Guidelines for Rating Debt Backed by Regulatory Assets* (New York: Fitch Investors Service, September 30, 1996).

Utilities may also be willing to accept a smaller reimbursement under this mechanism, since securitized payment involves a deferral of income tax liability. Ordinarily, an up-front compensation payment received by a utility would be taxable in the period in which it was received. Under securitization, however, the tax liability can be deferred and spread throughout the entire repayment period of the bonds.

Although it saves money, securitization does entail costs. Taxpayers bear part of the burden of stranded costs since the bonds are exempt from state income tax. Also, although the bonds are not municipal bonds, their risk-free, income-tax-free status competes with municipal bonds and may raise the cost of municipal borrowing.

On the whole, securitization may not be the best tool to use for recovering stranded costs for several reasons. First, because estimates of stranded costs are so variable, a state could precommit to a compensation amount that exceeded the utility's actual costs.²⁸ Second, as noted before, the utility could use its additional revenues in ways that would hinder competition in the electricity-generation market.

CONCLUSION

Restructuring the electricity industry and allowing customers to choose their electricity supplier can provide many benefits. Because of competitive choice, electricity prices may fall, utilities may make better decisions about investing in power-generating facilities, and customers may be offered new services, including power produced from renewable sources, real-time pricing (variable pricing based on when the electricity is used), and other pricing innovations such as electricity prices pegged to crop prices for agricultural customers.²⁹

Transitions can be costly. For a number of reasons—some within the control of current utilities and some not—the transition to a more competitive electricity industry will be especially costly for many current suppliers of electricity.

For reasons of fairness and political reality, utilities are likely to be compensated for some or all of their losses. Determining the correct figure for stranded costs, deciding how much of them to compensate, and figuring out how

28. Kenneth Rose, "Securitization of Uneconomic Costs: Whom Does It Secure?" *Public Utility Fortnightly*, vol. 135, no. 11 (June 1, 1997), pp. 32-37.

29. Statement of Jeffrey K. Skilling, President, Enron Corporation, before the Senate Committee on Energy and Natural Resources, March 6, 1997 (available at <http://www.senate.gov/~energy/competit.htm#skilling>).

that compensation should be paid are difficult issues, which are slowing progress toward restructuring in many states. The federal role in restructuring the electricity industry, and particularly in dealing with stranded costs, is uncertain. Federal action may be needed to break the legislative and regulatory logjams in some states.

On this issue, economic efficiency plays second fiddle to fairness and politics. Economists can recommend ways to estimate stranded costs, ways to pay them, and ways to collect fees for stranded costs that are the least distorting and least costly to the economy. Economists can also estimate the benefits of restructuring and identify likely winners and losers. But the decision to compensate—to ease the financial burden of restructuring on the owners and creditors of utilities—is ultimately one for regulators and legislators.