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## INTRODUCTION

Progress is evident on several fronts as the restructuring debate in the U.S. electricity industry completes its third year. The Federal Energy Regulatory Commission (FERC) released a final rule on transmission open access (FERC 1996)—a key element to facilitate more efficient wholesale markets. The majority of states have initiated investigations, proceedings, or discussions on restructuring retail markets. These state-level activities have promoted a broad examination of alternative market structures, policies to address market power in generation and transmission, the future of public-policy obligations, and different approaches to regulate monopoly services, among other issues. A few states have begun to implement restructuring proposals.

Yet hurdles remain to continued progress in formulating and implementing state-level restructuring proposals. Perhaps foremost among these hurdles is the issue of transition costs.[1] Transition costs are the potential monetary losses experienced by utilities, consumers, and other economic actors as a result of government initiatives to transform electricity generation from a regulated to a competitive market. Transition costs are approximately equal to the difference between the embedded cost for generation services under traditional cost-of-service regulation and the competitive-market price for power. When government takes action to open current monopoly franchises to multiple generation providers and the competitive-market price falls below embedded generation costs, then transition costs will arise. Transition costs will include one or more of the following four classes of costs (Flaim 1994):

- assets, primarily utility-owned power plants;
- liabilities, primarily long-term power-purchase and fuel-supply contracts;
- regulatory assets, including deferred expenses and costs that regulators allow utilities to place on their balance sheets; and
- public-policy programs, such as energy efficiency, low-income programs, and research and development.[2]

Early in the restructuring debate, researchers identified transition costs as a critical issue (e.g., Anderson, Graham, and Hogan 1993). FERC's initial proposed rulemaking to make wholesale

[1]We use the term "transition cost" because it is neutral as to who should pay and indicates that these are temporary costs revealed during the transition to a more competitive market for generation services. Others use the term "stranded cost" or "stranded investment" to refer to these temporary costs.

[2]Unlike the first three categories, the costs in this last category are current, not sunk.

markets more competitive was accompanied by a parallel rulemaking on the transition costs that might result from increased competition. Due to the close relationship between restructuring and its financial consequences, FERC's final rule addressed both issues (FERC 1996). Many states also recognized the importance of transition costs as they considered actions to make retail markets more competitive. In its initial restructuring proposal, for example, the California Public Utilities Commission (PUC) discussed the need to implement a competition transition charge for investor-owned utilities (California PUC 1994). In the California PUC's final policy decision, only the issue of market structure received more attention than transition costs (California PUC 1995).

What is at issue in the transition-cost debate? The debate turns on four questions:

- How large are the potential transition costs from restructuring?
- How are these costs estimated?
- What, if anything, might be done to address these costs?
- Who will ultimately pay for any remaining costs and how?

This paper summarizes some of the key results from a project at ORNL that addresses these four questions.

## THE SIZE OF POTENTIAL TRANSITION COSTS: NATIONAL ESTIMATES

Uncertainty over the magnitude of potential transition costs clearly contributes to the ongoing debate. One of our earlier studies (Baxter and Hirst 1995) identifies industry-wide estimates that range from $20 billion to $500 billion. Our study confirms that potential transition costs can differ widely, depending on assumptions about future market prices, the portion of retail load that obtains market prices, and the timing and pace of restructuring. We develop national estimates that ranged from $16 billion to $268 billion (1994 $) and suggest that the most plausible range for potential transition costs is $72 billion to $104 billion.

Other national studies report somewhat larger estimates of potential transition costs. Resource Data International (RDI 1994) reports industry-wide transition costs at $158 billion. A more recent study by Moody's (Fremont et al. 1995) presents a national estimate of $138 billion. Our estimates differ from RDI's and Moody's primarily because of the treatment of income taxes. Our estimates are net of the change in income taxes.[3] These estimates suggest that potential transition costs are substantial, though smaller than many earlier estimates, and that the range of national estimates is narrowing.

In addition, these three studies generally agree about how transition costs are distributed nationally (Baxter 1996). Figure 1, showing results by state for the high end of our most plausible range, suggests that potential exposure to transition costs is widespread. Only utilities in the upper Rocky Mountain states and the Pacific Northwest appear to be at little or no risk. Utilities at comparatively

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[3]For every dollar of lost revenue contributing to transition costs, the loss to utility shareholders is one dollar minus the utility's tax rate. See Baxter and Hirst (1995) for a detailed illustration of the effects of income taxes on transition-cost estimates.

greater risk are concentrated in the Northeast, Midwest, Southwest, California, and to a lesser extent in the Southeast. Because the potential exposure to transition costs is driven by differences between current embedded generation costs and short-term market prices for generation, customers in many of the states with the greatest potential exposure are applying political pressure to accelerate restructuring, thus increasing tensions over transition costs.

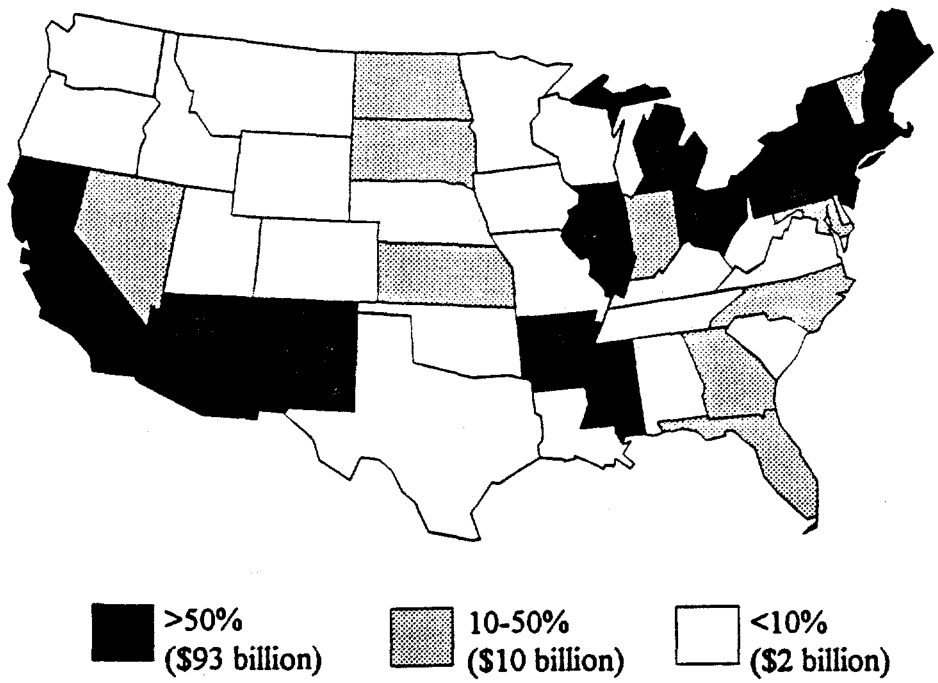


**Figure 1. Transition costs as a percent of utility equity (Source: Baxter and Hirst 1995).**

## DIFFERENT APPROACHES TO ESTIMATING TRANSITION COSTS

Our more recent work examined different estimation approaches. One report identified the broad array of general estimation approaches (Baxter 1995). We described these general valuation options using a classification framework initially suggested by San Diego Gas & Electric (1994).[4] Transition costs may be estimated, for example, using administrative or market valuation approaches. Administrative valuation methods use forecasting, modeling, or other analytical techniques to determine the market and regulated values of utility assets and obligations. Market valuation uses auctions, sales, appraisals, or asset spin-offs to determine the market value of assets. Either of these basic approaches may be applied before (ex ante) or after (ex post) industry

[4]See Baxter (1995) at 57 for a more complete description of general estimation approaches.

restructuring proposals are implemented. These basic approaches also either value assets individually (bottom up) or as portfolios (top down).

One strength of administrative approaches is that they allow all relevant categories of assets and liabilities to be included in the estimate. Use of administrative approaches, however, may require additional regulatory action to encourage improved utility-cost performance. Regulators will not wish to allow utilities to operate as if full recovery of all costs is guaranteed.

Market valuation approaches incorporating asset auctions or sales provide a clear indicator of value at the time of the sale. The timing of the sale will affect the market value; assets sold before restructuring will probably command a different price than if those same assets were sold after the details of restructuring are known. In addition, selling all generation assets at once will likely yield lower sale prices than selling assets in smaller amounts over a more extended time frame. Time also plays a role in market valuation approaches relying on asset spin-offs to affiliated companies. In these cases, the stock price is one indicator of market value, but determining the appropriate time(s) to observe stock price may be difficult and contentious. Market valuation approaches have the benefit of addressing the concerns with continued utility ownership of generation and transmission assets. Selling a utility's generation assets to several smaller suppliers will promote greater competition. Unfortunately, not all assets potentially contributing to transition costs have market value. Regulatory assets are a prime example. Other assets, such as nuclear facilities, have productive value, but concerns with future liability may inhibit market interest.

The key strength of ex ante approaches is that they provide an early estimate of transition costs. As a result, suppliers and consumers can plan for an industry transition with these costs clearly established. The cost of acquiring this early certainty is the risk of being wrong. Ex ante administrative approaches relying on a single estimate or single forecast of market price pose potentially large risks for shareholders and ratepayers. Such approaches are untenable and suffer from the misuse of analysis and models as substitutes for, rather than guides to, decision making. Ex ante methods must face the difficult problem of anticipating the market response to a still undetermined industry and regulatory structure. The important advantage of ex post options is that they resolve the uncertainty issue by delaying valuation until after industry restructuring is underway and a mature electricity market develops. Delaying valuation to this extent, however, is unreasonable. Standard accounting practices and the financial markets may compel utilities to write off or mark down certain assets well before a competitive market matures.

Bottom-up options result in assigning market values to individual assets. This feature addresses important accounting concerns (e.g., standard accounting practice requires that changes to book values be made for specific assets). In contrast, top-down approaches value overall changes to a portfolio of assets. Administrative bottom-up options also provide a wealth of information about the profitability of different assets or insights about the behavior of future markets. These details and insights come at the price of data intensiveness, computational complexity, and the attendant administrative difficulties associated with litigating numerous assumptions. Administrative top-down approaches are easier to understand and implement. The opposite may be true for market approaches. Individual asset sales may be simpler to administer than asset portfolios or packages.

Yet asset portfolios may make less desirable assets more marketable. For example, utilities might entice buyers to purchase a share of a nuclear plant by combining the share with a fully depreciated fossil plant. In addition, selling certain plants together may bring in more cash than selling them separately if certain positive synergies exist among the plants.

This discussion of general estimation approaches illustrates that no single type of valuation approach is without a substantial weakness, particularly when the objective is to provide transition cost estimates that regulators authorize utilities to recover. For this important objective, combinations of these general approaches will be needed or solutions must be developed to address the weaknesses of any preferred approach.

We also reviewed several specific valuation approaches and found that they differed in several key areas, each of which will contribute to differences in transition-cost estimates:

- the methods used to estimate market prices;
- the comparison of market and regulated prices;
- the assets and liabilities included in the analysis; and
- the time period used to estimate revenue losses.

Another report focused on specific types of administrative valuation approaches (Hirst, Hadley, and Baxter 1996a). We found that aggregate and disaggregate approaches sometimes yield substantially different transition-cost estimates. These differences are driven primarily by a utility's often complex interaction with the wholesale electricity market.

**Recommendations: Which Approaches to Use**

Regulators and legislators have at least two major uses for transition cost estimation. The first is to identify and assess the extent of transition costs for utilities in their state or region. The second is to provide an analytical foundation for utility recovery of transition costs. Based on our assessment of different approaches, which methods are suited to these applications?

Regulators should use ex ante administrative valuation approaches to initially assess the potential existence and extent of transition cost problems in their jurisdictions. Top-down methods will be most suitable for organizations with limited resources or when the detail provided by a bottom-up approach is unnecessary.

When the application is for regulatory authorization of transition cost recovery, regulators should use ex ante administrative valuation approaches, particularly where continued utility ownership of existing generation and transmission assets is not a major concern. At least two options are available to address the forecast risk introduced by ex ante administrative approaches.

- Use a reconciliation process to periodically compare forecasted to observed market prices and utility revenues, and then appropriately adjust subsequent transition cost recovery.

Implementing a reconciliation process requires the development of appropriate market price indicators and incentives for efficient cost recovery.

- Alternatively, recognize that a certain level of forecast error is unavoidable. Reconciliation would then only be initiated if an interested party demonstrates that actual transition costs deviate from the forecast by a predetermined amount.

Market valuation is an attractive approach when continued utility dominance of generation markets is a substantial concern. The sale of less marketable generation assets will be enhanced by combining these less attractive assets with more attractive assets. The Sant and Naill (1994) proposal combines this feature with a long-term power purchase contract between the asset buyers and sellers. If retail competition is an objective, however, this proposal delays retail competition until the initial power-purchase agreement expires. Disposition of nuclear assets is also a key problem with market valuation approaches. In addition, regulators will still have to use administrative methods to value the contribution of other major asset categories to transition costs.

**An Assessment Framework: The Forest From the Trees**

When faced with conflicting claims about transition costs, policy makers need a framework to assess different cost estimates and estimation approaches. Following is an initial proposal for such a framework, which identifies the key issue areas important to consider when reviewing specific approaches and results.

**Implementation**. Implementation describes how valuation is conducted technically and procedurally. Administrative valuation methods typically are implemented using computer models. Market valuation methods are implemented by auction, sale, spin-off, or some other market process. Implementation also refers to the need for regulatory proceedings to review estimates, estimation methods, or supporting data.

**Administrative Ease**. From the regulator's perspective, administrative ease refers to the relative difficulty of implementing the approach and administering any associated proceedings. "High" administrative ease means the approach is simple and the amount of regulatory involvement in proceedings is comparatively slight.

**Publicly Available Data or Models**. This category indicates whether the data or models necessary to calculate transition costs are publicly available or proprietary. A proprietary model may be available through licensing agreements or other commercial arrangements.

**Relevant Assets and Liabilities**. This category describes whether the approach includes those assets and liabilities that many industry analysts agree should be included in transition cost estimates.

**Time Period**. The time periods used to estimate transition costs differ depending on the level of aggregation in the analysis. For example, the time periods covered for utility generation and power-purchase contracts often differ.

**Market Price (Value) Determinations**. Market price determinations are made using either analytic techniques (price estimates—the basis for administrative valuation) or observing appropriate market indicators. Price estimates are developed endogenously or exogenously. Endogenous price estimates are not predetermined assumptions or externally imposed by the analyst, but are instead the result of market simulations or an analysis that explicitly accounts for the economics of plant dispatch in a region. Hence, they are an intermediate result of the analytic method used to calculate transition costs. In contrast, exogenous price estimates are derived directly from an assumption or an observation about the cost of different generation options. This estimate is then included as a key input in the transition cost estimate.

**Price (Value) Comparisons**. Transition cost approaches invariably involve a comparison of an asset's value under regulation to its market value. Parity refers to whether the regulated price and the market price are composed of comparable elements. Comparing a fully bundled residential retail rate to the per unit cost of new generation is inappropriate if the objective is to estimate transition costs from the deregulation of generation. The fully bundled retail rate includes the cost of basic services such as generating capacity, energy supply, and power delivery as well as a host of ancillary and customer services. Including these cost elements in the regulated price assumes that these services (and the asset value they represent) will all be potentially stranded by the move to deregulate generation. Including any return on investment (ROI) in the valuation is also important because it has a substantial effect on most transition cost estimates. Including ROI in the analysis is not necessarily incorrect, although the debate on this issue is still active. Finally, taxes indicate whether the effects of income taxes are included in the approach. A dollar revenue loss to the utility does not translate as a dollar loss to shareholders because the utility does not have to pay federal, state, or local income taxes on the lost revenue.

**Market Forces**. Utility actions and the actions of the larger marketplace affect transition costs. For example, high-cost utilities will respond to increased competition by lowering costs. Many utilities will pursue previously protected markets to increase sales. Both these effects will affect the transition costs that utilities ultimately face. Similarly, the wider marketplace will also respond to increased competition. Over time, electricity prices will change. These changes should lead to short-run and long-run changes in demand. Should current capacity surpluses tighten, prices should rise thus stimulating development of new supplies. The interaction of demand and supply over time will in turn determine future market prices, which directly affect transition costs.

## Key Factors that Affect Transition-Cost Estimates

In a more recent report, we conducted a detailed sensitivity analysis to improve understanding on the part of state and federal regulators, utilities, customers, and other electric-industry participants about the relative importance of the factors that affect transition-cost amounts (Hirst, Hadley, and Baxter 1996b).

We created a hypothetical U.S. utility with a substantial transition-cost problem. Between 1996 and 2000, the portion of retail load that "leaves" the utility increased from 8% to 42%. We analyzed the consequences of this retail wheeling from two perspectives: utility shareholders (in which case customers are held harmless and face the same rates with or without retail wheeling) or remaining retail customers (in which case utility shareholders are held harmless and earn the same return on equity with or without retail wheeling).

We divided the many factors that affect retail-wheeling losses into three groups:

- Regulatory factors that affect the timing and extent of retail wheeling, including the year that retail wheeling begins, the number of years for which transition-cost recovery is allowed, and the type and frequency of rate cases.

- Wholesale-market factors that affect the interactions between the utility and wholesale power markets, including wholesale prices, utility marginal production costs, transmission capacity, differences between wholesale purchase and sale prices, and the extent of retail wheeling.

- Accounting factors that affect the utility's income statement and balance sheet, including regulatory assets, fixed production costs, ancillary-services charges, inflation rate, and other minor factors.

Results differ according to whether the utility keeps the sales at risk and sells power to these customers at market prices or whether the utility loses the sales and seeks to resell some or all of the freed-up power on the wholesale market. Results also differ depending on whether the utility or its remaining retail customers bear the transition-cost losses.

In spite of these differences, our analyses show that a few factors dominate (Figure 2). The key variables that most affect losses include the year that retail wheeling begins, wholesale prices (or, equivalently, utility marginal production costs), the percentage of customers that wheel, fixed production costs, regulatory assets, and capacity-related charges for ancillary services. Many other factors, including frequency and type of rate cases, public-policy-program costs, inflation rate, customer load factors, transmission and distribution (T&D) loss factors, and load growth, have only small effects on the losses caused by retail wheeling.

Of the critical factors shown in Figure 2, some can be influenced by the utility and some by the PUC, and some are essentially beyond the control of either party. As examples, the PUC can affect the start date and extent of retail wheeling, although market forces may overwhelm regulation where large price disparities exist; and utilities can seek to cut their fixed and variable production costs and to sell ancillary services. But wholesale prices—by far the most important factor—are largely independent of utility or PUC actions.

Whether the remaining retail customers or the utility shareholders bear the losses associated with transition costs has little effect on the results obtained. That is, the key factors affecting estimates of losses are the same for both perspectives. However, the distinction between the keep-sale and lose-sale options (i.e., whether the utility keeps the sales at risk and sells to those customers at market prices vs whether the utility loses those sales and seeks to resell some or all of the capacity and energy freed up on the wholesale market) can be important.

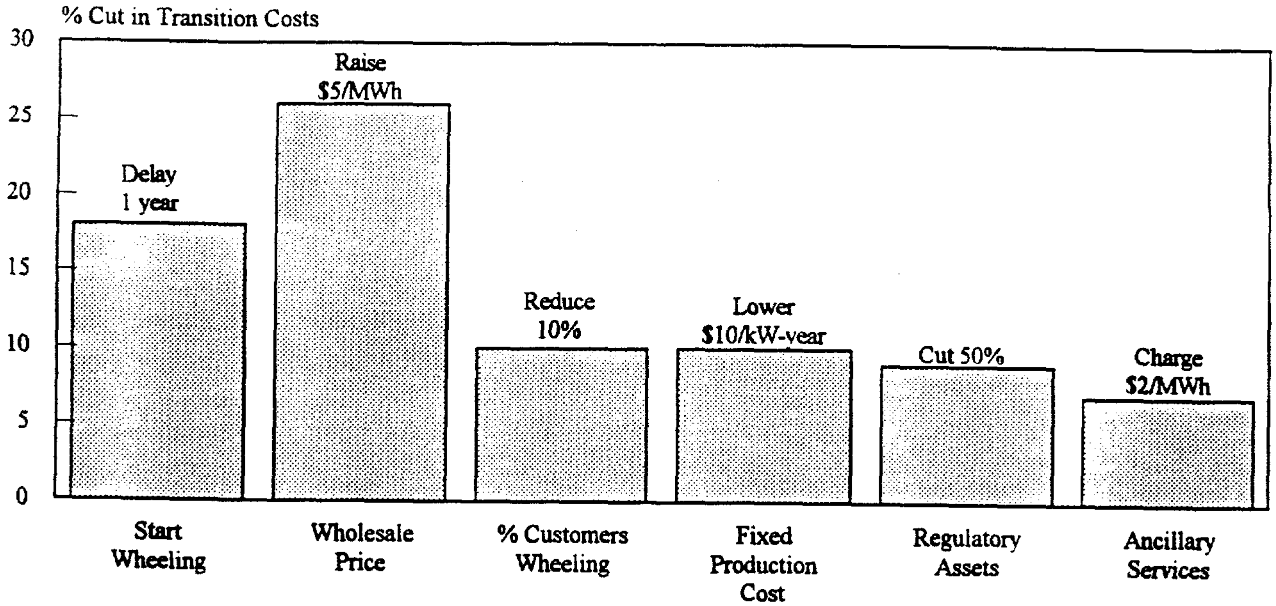


**Figure 2. Effects of the key factors that influence transition-cost losses. The base case against which these results are developed includes: retail wheeling begins in 1996, the wholesale price is $25/MWh (and the marginal cost of the utility's generation is $24/MWh) in 1995, 50% of the commercial/industrial customers plus 25% of the residential customers are wheeling by the year 2000, fixed production costs amount to $186/kW in 1995, and there is no ancillary-services charge.**

## STRATEGIES TO ADDRESS TRANSITION COSTS

Most transition-cost estimates, including the studies discussed above, focus on a utility's potential exposure to these costs. Because state-level initiatives to restructure retail electricity markets are still at an early stage, analysts have begun to examine the cost structure of electric utilities to develop strategies regulators or utilities might use to reduce the exposure of different economic actors to transition costs. Figure 3 is a snapshot of the electric-utility industry's cost structure in 1994. The left pie displays total annual utility costs by function. Generation costs clearly dominate overall utility costs, which underscores the importance that the economic deregulation of generation has for the industry. The dominance of generation costs also, perhaps, explains why many analysts expect large efficiency gains, or cost reductions, from deregulating generation services.

The right pie displays the same total annual costs, but by cost category. Fremont et al. (1995) use a similar chart to argue that utility management has only a limited ability to reduce absolute costs. Fremont et al. argue that operations and maintenance costs are the only cost categories over which management has considerable control and that these costs are a relatively small portion of total costs. They note that reducing other costs will require the cooperation of other parties. Although fixed fuel costs under long-term purchases are important, Fremont et al. are pessimistic that utilities will be able to renegotiate lower fixed payments under existing long-term power-purchase and fuel-supply contracts.

The pessimism of Fremont et al. may prove to be justified, but to date analysts have done little systematic analysis of the effects different strategies may have on transition costs. Without such analysis, we urge caution in dismissing potential strategies, even those that require the participation of parties beyond the affected utilities. For certain utilities, the potential transition-cost risk is too great to foreclose promising strategies without further exploration.

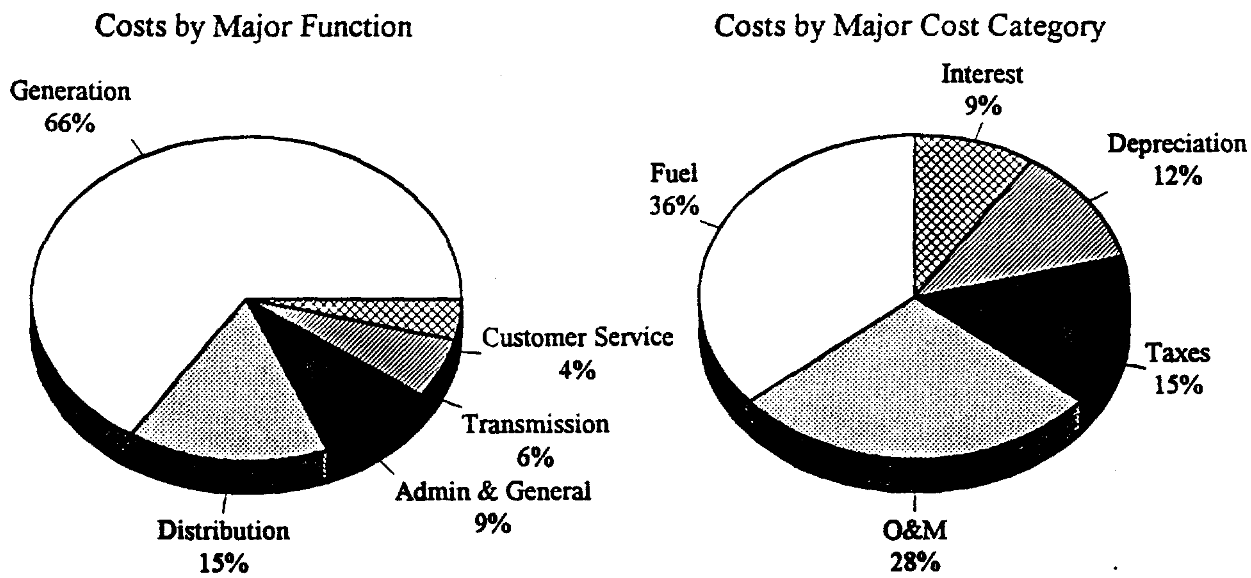


**Figure 3. Distribution of costs for U.S. investor-owned electric utilities in 1994 (Source: EIA 1995). Total costs = $163 billion.**

Several writers refer to these strategies as ways to "mitigate" transition costs. Strictly speaking, transition costs, to the extent they reflect sunk costs or obligations, cannot be mitigated. Utilities cannot reduce costs on a plant already purchased any more than consumers can save money on electricity already consumed. Virtually all the strategies that we identified involve shifting costs among different segments of the economy (Baxter, Hadley, and Hirst 1996). Costs may shift from one group to another, between electricity consumers and producers, for example, or from future ratepayers to present ratepayers.

To illustrate, consider an extreme example—immediate opening of retail electricity markets. Under traditional regulation, a utility is permitted to recover all prudently incurred costs of providing service to all the customers within its franchise service area in return for state regulation of rates and profits. If regulators simply open the utility's retail markets to other electricity suppliers, all revenue shortfalls and resulting transition costs fall on utility shareholders.

A less extreme example helps distinguish between strategies that merely shift costs and those that result in efficiency gains. Consider a utility that reduces administrative costs by $100 million. Under traditional cost-of-service regulation, utility shareholders accrue these savings as increased earnings until the next rate case, at which point rates will be lowered to reflect the utility's new cost of service. Only after these new rates are established are the cost savings passed to ratepayers. As a mitigation strategy for transition costs, these cost savings could be used to reduce the utility's transition costs by $100 million. One way to implement this strategy is to hold current rates constant; the cost savings are not reflected in revised rates. A more equitable strategy is to share these administrative cost savings between shareholders and ratepayers. Consumers are better off because their total price for electricity is lower than if the utility had not reduced administrative costs. Utility shareholders are better off because a portion of the cost savings can be used to lower embedded generation costs and, as a result, transition costs. Thus, strategies that reduce costs result in efficiency gains that can be used to offset transition costs.

From filings at FERC, state proceedings, published literature, industry press, and consultant reports, we compiled a list of strategies that may be implemented to address transition costs. We grouped the many individual strategies located during our review into six major categories:

- Market actions affect the market structure for electricity or rely on market mechanisms.
- Depreciation options modify the depreciation of utility assets.
- Rate-making actions change the rates utilities charge for electricity service.
- Utility cost reductions offset transition costs or lower electricity prices.
- Tax measures increase taxes or use tax reductions or deductions.
- Other options include a handful of strategies not falling in the first five categories.

From the 34 individual strategies identified and discussed in our report (Baxter, Hadley, and Hirst 1996), this paper discusses the 21 strategies that merit continued attention because of their prominence in restructuring proceedings and decisions.

As we discussed earlier, transition-cost strategies typically involve shifting costs among groups, either immediately or across time. Table 1 presents our qualitative assessment of which party will bear the transition costs under each strategy. For many strategies, the identity of the affected party or parties is clear. For example, rapidly opening retail markets, in the absence of other measures, will clearly harm shareholders of those utilities with above-market generation costs. For other strategies, the consequences are not so clear cut because regulators and legislators will have a large effect on who bears the transition costs. In these cases, we assume that decision makers will act to distribute costs across groups. For example, regulators can structure rates so the benefits of reducing utility costs either flow completely to shareholders or to ratepayers. We assume regulators will decide to share utility cost reductions with both groups. Similarly, regulators can approve performance-based-rate-making mechanisms that largely insulate shareholders from market risks, but we assume that regulators will approve mechanisms that will shift the preponderance of market risk (in return for a greater opportunity to achieve market rewards) from ratepayers to shareholders.

**Table 1. Different transition-cost strategies and the parties most likely to bear the costs[a]**

| Strategy | Utility Shareholders | Retail Ratepayers | Taxpayers | Wheeling Customers | QFs, IPPs |
|---|---|---|---|---|---|
| **Market Actions** | | | | | |
| Open markets | ✓ | | ✗ | | ✗ |
| Delay competition | | ✓ | | | |
| Divest utility plant | ✓ | | ✗ | | |
| Merge[b] | | | | | |
| Market excess power | ✓ | ✓ | ✗ | | |
| **Depreciation Options** | | | | | |
| Alter depreciation | | ✓ | | | |
| Transfer depreciation reserves | | ✓ | | ✗ | |
| **Rate-Making Actions** | | | | | |
| Reduce utility returns | ✓ | | ✗ | | |
| Restructure/unbundle rates | | ✓ | | ✗ | |
| Performance-based rates | ✓ | ✗ | | | |
| Disallow costs | ✓ | | ✗ | | |
| Exit fees | | | | ✓ | |
| Access charges | | ✓ | | ✓ | |
| **Utility Cost Reductions** | | | | | |
| Reduce operating costs | ✓ | ✓ | | | |
| Reduce power-purchase costs | ✓ | | | | ✓ |
| Reduce public-policy- | | | | | |
| Financial write-downs | ✓ | | ✗ | | |
| **Tax Measures** | | | | | |
| Consumption/production tax | | ✓ | | ✓ | |
| Tax reduction/deduction | | | ✓ | | |
| **Other Options** | | | | | |
| Eliminate obligation to serve | ✓ | | ✗ | | |
| Statutorily authorized | | ✓ | | ✓ | |

[a]A "✓" indicates the actor with primary responsibility, while an "✗" indicates secondary responsibility.

[b]Assessing the effects mergers will have on transition costs is difficult. A given merger could potentially benefit or harm any or all the actors listed.

[c]To the extent that reductions in public-policy-program costs reflect reductions in services, prospective program participants and society in general will bear the transition costs.

Of the 21 strategies we discuss, utility shareholders and retail ratepayers have primary or secondary responsibility for paying transition costs in 10, taxpayers in 9, wheeling customers in 6, and nonutility suppliers in 2. For two of the strategies, mergers and public-policy-program cost reductions, assigning costs to any of these parties in advance is difficult.

Taxpayers will shoulder some portion of transition costs unless changes to the current tax codes are made. As we noted previously, utility revenue losses from retail wheeling will be partially offset by reductions in income-tax payments. Utilities may also be able to take a charge against income when writing down above-market assets. Although we do not explicitly note the tax consequences of delaying competition, most businesses deduct operating expenses. As a result, the higher electricity costs that businesses will experience from a delay in competition will be partially offset by reductions in taxes. Residential taxpayers, of course, will not benefit from this tax effect.

Absent regulatory or legislative actions, most divestiture strategies will leave transition costs with utility shareholders and taxpayers. An exception would be the strategy proposed by Blank, Gilliam, and Wellinghoff (1996). In their proposal, the allocation of transition costs depends on the price for generation services negotiated by the nonprofit T&D company. Assuming that this price is below the generation company's embedded costs but above spot market prices, then utility shareholders and retail ratepayer [and qualifying facilities (QFs), to the extent the generation company itself has long-term contracts with QFs] will bear the transition costs. The reduction in federal income taxes under this proposal depends on the size of the nonprofit's electric operations relative to the former utility's total electric operations.

Our assessment for marketing excess power differs from how we assess other strategies. Here we indicate which party will be hurt when the utility does not pursue profitable market opportunities. Shareholders will forego these margins and the federal treasury will lose the income tax from these earnings. Retail ratepayers will face higher rates if the utility operates generating units when cheaper power is available for purchase.

Unless regulators explicitly allocate costs to shareholders, all the depreciation options shift costs to retail ratepayers. This shift occurs over time, however. Accelerated depreciation shifts costs from future ratepayers to current ratepayers. Accelerated depreciation may also affect the utility's income-tax bill depending on each asset's original book depreciation schedule and when accelerated depreciation begins and ends relative to this original schedule. Depending on these respective schedules and the observation period, the net effect on income taxes could be positive or negative. Because these tax effects are specific to each asset, we do not reflect them in Table 1. Assessing the effects of a transfer of depreciation reserves is complicated. A depreciation reserve transfer has no impact on rates if the transfers are offsetting, utility rates remain bundled, and cost-of-service differences between customer classes are ignored. Once rates are unbundled, however, this strategy is difficult to implement without shifting costs to retail ratepayers and wheeling customers. Such cost shifting is difficult to avoid when transferring costs from the soon-to-be-deregulated (i.e., generation) to the regulated (i.e., T&D) side of the utility.

Restructuring and unbundling rates allocates most costs to retail ratepayers. Unbundling rates allocates some costs to wheeling customers, however, should they continue to pay for ancillary services or nongeneration-related customer services and administrative and general expenses. The access-charge strategy allocates costs to retail ratepayers and wheeling customers. Eliminating the utility's obligation to serve primarily affects shareholders because utilities are freer to retire uneconomic assets or to reduce reserve margins. Statutorily authorized cost recovery is an attractive solution to recover those public-policy investments that create regulatory assets. Costs are recovered from all ratepayers on the utility's system when the investment was made, including those that subsequently become wheeling customers

## WHO WILL ULTIMATELY PAY FOR TRANSITION COSTS?

Perhaps the most important, and difficult, transition-cost issue facing regulators is deciding how to allocate transition costs among the various parties, including utility shareholders, retail customers in different classes, independent power producers, and perhaps others.

Not surprisingly, debates at the state and federal level on this issue have been quite heated. In part, this is a consequence of the large dollar amounts at stake. In part, this may be a consequence of the strong policy, rather than analytical, basis for deciding this issue. In other words, analysis has little to contribute to legislative and regulatory decisions concerning the allocation of these costs.

### Pro-Recovery Arguments

The primary proponents of the argument that utilities are entitled to, and should receive, full recovery of their transition costs are, not surprisingly, the investor-owned utilities themselves. Baumol, Joskow, and Kahn (1994) offer what are perhaps the foremost arguments, based on economics and regulatory policy, supporting full shareholder recovery of stranded costs. The authors suggest that increasing economic efficiency should be the primary objective of restructuring the electricity industry. They argue that, when properly structured, competitive markets are more likely to increase economic efficiency than are regulated markets. These efficiency gains will involve both productive efficiency (i.e., providing goods at minimum cost) and allocative efficiency (setting prices correctly, based on marginal costs).

The authors' primary conclusion is that equity and productive efficiency considerations support a policy of full transition-cost recovery for utility shareholders. On the equity side, the authors believe that shareholders have not previously received compensation from their allowed equity returns for the risk they now face of not being able to recover their investments due to changes in government policy. Further, they note that utilities incurred most of these costs with the full approval, and sometimes at the mandate, of regulators. Should shareholders fail to recover transition costs, the efficiency consequences include distortion of competition between utilities and alternative suppliers, extension of the transition to competition, and the possibility of increased capital costs to the electricity industry.

The authors indicate that recovery of transition costs can be compatible with efficient competition when the recovery mechanism is properly structured. Joskow (1996) provides more detail on this issue. To ensure that the outcome of competition between rival suppliers is based on which is more efficient, the authors conclude that the costs of historical obligations must be assessed from all customers who have benefited from these obligations.

Rowe and Graening (1996) develop legal arguments to justify full payment to utility shareholders of stranded costs. Based on the Takings Clause of the Fifth Amendment, they argue that the government may require private property owners to cede rights to that property to serve the public good, but it must then ensure just compensation to the owner. Paying transmission owners the embedded costs of their transmission system is irrelevant, in part because transmission is an integral part of a utility's larger generation, transmission, and distribution system. Allowing others to use a utility's transmission system adversely affects of the value of a utility's generation assets and for this reduction in value the utility is entitled to full compensation.

**Anti-Recovery Arguments**

Large industrial customers and low-cost utilities, among others, oppose payment of full transition costs to utilities. They argue that payment of transition costs to utilities will have anti-competitive and uneconomic consequences by providing payments to high-cost producers that will have the effect of discriminating against low-cost producers. Full cost recovery also ignores any responsibility that utilities have for these costs (through poor management decisions).

Rose (1996) argues that recovery of transition costs by utility shareholders is not supported on grounds of either economic efficiency or historical regulatory policy. He states that the concept of transition costs, and arguments for its recovery by utility shareholders, has little basis in economic theory, legal precedence, or precedence in other deregulated industries.

Rose first considers the argument that transition-cost recovery is required for economic efficiency. This argument, he writes, is based on a narrow definition of efficiency—preventing "uneconomic bypass" of the utility's system (i.e., selecting another supplier when the utility is the lowest-cost provider for that customer). He argues instead for a broader perspective on efficiency, one that considers the long-term promotion of competitive markets and incentives for suppliers to minimize costs over time. In his view, longer-term gains from price reductions to consumers are likely to exceed the shorter-term losses from uneconomic bypass. Rose further argues that allowing transition-cost recovery may impair the development of competitive markets by reducing utility incentives to lower costs, acting as a barrier to entry and exit of other suppliers in the marketplace, and creating an asymmetry between utility risk and reward.

Rose next considers the argument that cost recovery is required to comply with historical regulatory policy (i.e., the "regulatory compact"). He discusses differing interpretations of this compact and concludes that full recovery of transition costs would be inconsistent with historical regulatory policy in many states. The only entitlement granted to utilities is the revocable privilege to serve an exclusive territory, from which stems the obligation to serve. This entitlement is not an agreement to pay all prudent (and other) costs; customers have no reciprocal obligation to purchase from the utility unless a written contract is in place.

**Government Decisions**

At the federal level, the Council of Economic Advisers (1996) favors utility recovery of transition costs:

> In unregulated markets the possibility of stranded costs typically does not raise an issue for public policy—it is simply one of the risks of doing business. However, there is an important difference between regulated and unregulated markets. Unregulated firms bear the risk of stranded costs but are entitled to high profits if things go unexpectedly well. In contrast, utilities have been limited to regulated rates, intended to yield no more than a fair return on their investments. If competition were unexpectedly allowed, utilities would be exposed to low returns without having had the chance to reap the full expected returns in good times, thus denying them the return promised to induce the initial investment. A strong case therefore can be made for allowing utilities to recover stranded costs where these costs arise from after-the-fact mistakes or changes in regulatory philosophy toward competition, as long as the investments were initially authorized by regulators. ... The case for allowing recovery is even stronger where stranded costs arise from regulatory obligations imposed on utilities [such as PURPA QFs]. ... . To be sure, utilities should be granted recovery only of costs prudently incurred pursuant to legal and regulatory obligations to serve the public.

FERC (1996), in its Order 888, came down clearly on the side of utility recovery of "legitimate, prudent, and verifiable costs." Similarly, the California PUC (1995) and the California Legislature (1996) both decided in favor of allowing utilities the opportunity to recover their transition costs. FERC provides an extensive discussion of the many comments it received on this issue, both for and against cost recovery, and the basis for its decision to allow utilities the opportunity to recover all their transition costs.

FERC's decision limits utility recovery of costs to only those that can be directly attributable to FERC's Order 888 providing for open-access transmission. If, for example, a wholesale customer physically leaves a utility's service area, the utility's losses associated with this departure would not qualify for cost recovery under FERC's rule. In addition, FERC limited recovery to costs incurred prior to July 11, 1994, the date of its original stranded-cost notice of proposed rulemaking. Finally, FERC requires a utility to demonstrate that it had a "reasonable expectation" to serve the departing wholesale customer for a certain amount of time. Thus, although FERC decided to allow utilities the opportunity to recover 100% of the costs stranded by increased transmission access, FERC clearly limited these opportunities to those that are a direct consequence of its actions.

Both FERC and California dealt with the allocation of costs among parties. With respect to the utilities themselves, both entities put in place mechanisms to encourage utilities to cut. FERC ruled that departing wholesale customers will pay the transition costs associated with their departure. This decision ensures that neither utility shareholders nor other wholesale customers bear the costs associated with a particular customer's departure.

The California Legislature (1996) sought to ensure that residential and small commercial customers would benefit from restructuring that state's electricity industry. To that end, the legislature authorized the issuance of up to $5 billion of government bonds, the proceeds of which would be used to guarantee residential customers a minimum 10% rate reduction and help pay for transition costs. The lower interest rate on government vs utility bonds and the longer amortization period (10 vs 5 years), plus the possibility of an exemption from federal income taxes, will be used to provide the rate reduction to residential customers. The Legislature decided that all retail customers will pay for transition costs through a nonbypassable Competition Transition Charge, allocated across rate classes in a manner similar to the customer-cost allocation in place as of June 1996.

Hanger (1996) suggests "different recovery levels for different types of stranded investments." Commissions should consider the degree of utility-management responsibility for the transition costs that exist in each category. In addition, the transition costs associated with utility-owned generation assets includes both a return *of* investment and a return *on* investment; Commissions can consider these types of costs differently for recovery purposes.

We believe that the regulatory and legislative decisions in favor of full-cost recovery are based on both philosophical and practical reasons. Philosophically, the federal and California governments recognize that many of the utility decisions that led to above-market costs (especially the construction of nuclear plants and the purchase of electricity from qualifying facilities) were actively promoted by government. Even where decisions were not promoted by governments, governments acknowledge that the regulatory commissions approved those actions.

Practically, it would likely be very difficult to implement a new industry structure without the support of utilities. If utilities were informed that they would not be permitted to recover transition costs, they could find many ways to delay implementation of competitive markets. For example, although the Michigan Public Service Commission mandated a retail-wheeling experiment in 1994, retail wheeling has yet to begin in that state.

## CONCLUSIONS

Transition costs are a key issue in debates about changes in the structure, operation, and regulation of the U.S. electricity industry. Regulators, electric utilities, nonutility power producers, marketers, brokers, and customers argue about the analysis, quantification, mitigation, allocation, and recovery of transition costs. To reduce such conflicts, which are a direct consequence of the large dollar amounts at stake, participants need to agree on appropriate methods to use to calculate transition costs, on the key factors (and their values) that affect these losses, and on the pros and cons of different methods to minimize such costs.

The potential losses a utility or its remaining retail customers might face because of retail wheeling can be calculated in many ways. Every general estimation approach has at least one substantive weakness. As a result, regulators must consider combinations of the general approaches or develop solutions to the weaknesses of a selected approach. We recommend that regulators use administrative valuation approaches to initially assess transition cost problems in their jurisdiction. For regulatory authorization of transition cost recovery, we recommend the use of administrative valuation approaches where continued utility ownership of existing generation and transmission assets is not a major impediment to a competitive power market. Market valuation is an attractive approach when continued utility dominance of generation markets impedes the operation of competitive power markets.

Although many factors affect transition-cost estimates, only a few factors have substantial effects on the magnitudes estimated. These critical factors include the start date for retail wheeling, the amount of retail load that is eligible for wheeling, differences between wholesale (spot) prices and utility marginal production costs, and utility fixed production costs.

We identified a wide range of strategies to address transition costs. These strategies rely on market actions, depreciation options, rate-making actions, cost reduction options, and other approaches. Many of the proposed strategies essentially shift costs from one set of economic actors to another (i.e., among utility shareholders, retail customers, wheeling customers, and independent power producers). Several cost-reduction options rely on efficiency gains to offset transition costs, and must be distinguished from strategies that simply shift costs.

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