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Strategies To Address Transition Costs in the Electricity Industry

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MANAGED AND OPERATED BY
LOCKHEED MARTIN ENERGY RESEARCH CORPORATION
FOR THE UNITED STATES
DEPARTMENT OF ENERGY

ORNL-27 (3-96)

ORNL/CON-431

ENERGY DIVISION

STRATEGIES TO ADDRESS TRANSITION COSTS IN THE ELECTRICITY INDUSTRY

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July 1996

Sponsored by
Coal and Electric Analysis Branch
Energy Information Administration
and
Office of Utility Technologies
Office of Energy Efficiency and Renewable Energy
U.S. Department of Energy

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Oak Ridge, Tennessee 37831
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LOCKHEED MARTIN ENERGY RESEARCH CORPORATION
for the
U.S. DEPARTMENT OF ENERGY
under contract No. DE-AC05-96OR22464

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SUMMARY

Transition costs are the potential monetary losses that electric-utility shareholders, ratepayers, or other parties might experience because of structural changes in the electricity industry. As the restructuring debate in the electricity industry enters its third year, the question of how to address transition costs remains a major impediment to more rapid progress on several other issues, including market structure, customer access and choice, regulatory jurisdiction, and the timing of restructuring. Regulators, policy analysts, utilities, and consumer groups have proposed a number of strategies to address transition costs. Suggested strategies posit actions and effects that vary broadly, such as immediately opening retail electricity markets (and letting utility shareholders bear all transition costs) or delaying retail competition (and assigning the preponderance of costs to retail ratepayers). Despite the role of transition costs in the larger restructuring debate, little systematic analysis of different transition-cost strategies is publicly available.

Our report has three objectives. First, we identify a wide range of strategies available to regulators and utilities to address transition costs. Second, we systematically examine the effects of selected strategies on transition costs. As one byproduct of this objective, we develop an assessment framework useful for examining transition-cost strategies. Finally, we identify potentially promising strategies that may provide benefits to more than one set of stakeholders.

We review filings at federal and state proceedings, published literature, industry press, and consultant reports to compile the list of available strategies. We group the many individual strategies 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.

Of the 34 individual strategies we identify, retail ratepayers have primary or secondary responsibility for paying transition costs in 19 of the strategies, shareholders in 12, wheeling customers in 11, taxpayers in 8, and nonutility suppliers in 4. Most of the strategies we identify shift costs among different segments of the economy (e.g., from shareholders to retail ratepayers), although certain strategies use utility cost reductions to offset transition costs.

We use an integrated utility planning model to assess the effects of different strategies on transition costs. In assessing most strategies, we follow three steps. First, we define a base-case utility and use it to assess each strategy. Second, we create a retail-wheeling scenario and

estimate the financial consequences relative to the base case. Third, we incorporate a specific strategy into the planning model and estimate the resulting financial consequences. Our estimate of each strategy's effect is the difference in transition costs for the retail-wheeling scenario with and without the strategy. We examine reasonably complete representations of ten individual strategies (e.g., opening markets, delaying competition, marketing excess power, accelerating depreciation, unbundling rates, and reducing power purchase costs) and partial representations of two others. One of these 12 strategies, reducing utility operating costs, we examine in detail, studying four separate areas of utility cost performance and cost reduction potential.

Table S-1 groups the different strategies we assess by their potential effects on the base-case utility's transition costs. Because the absolute effects of different strategies are linked to the assumptions that define our base-case utility, this table provides a more general indication of how a strategy may affect other utilities. When reviewing Table S-1, keep in mind that potentially affected utilities are not representative of all U.S. utilities. Potentially affected utilities will have substantial above-market costs in at least one of three areas: utility-owned generation, long-term purchase obligations, and regulatory assets.

Strategies with potentially large effects change transition costs to utility shareholders by 25% or more. For at-risk utilities, delaying retail wheeling, charging exit fees to departing customers, and discounting energy payments to qualifying facilities to market prices are all likely to result in large reductions in utility transition costs. Rapidly opening retail markets will lead to large increases in transition costs for at-risk utilities.

The effects of the utility's failure to market the energy freed by departing retail customers are difficult to assess. One case we examine results in a large increase in utility transition costs, but another case yields a modest reduction in costs. Our results suggest that the benefits (or costs) of marketing excess energy are related to the marginal generation costs of the utility's own plants, the operation and cost obligations of qualifying-facility plants under contract to the utility, and the opportunities available in the wholesale market.

Reductions in nongeneration costs, such as administrative and general costs, may have substantial effects on transition costs. The comparative importance of reducing specific nongeneration costs depends on the cost structure of the utility in question. For our base-case utility, attaining a cost-performance standard in administrative and general operations (as defined by the lowest-cost firms in the industry) reduces its transition costs substantially. For utilities with nongeneration costs close to or slightly below the industry average, the cost-reduction potential declines accordingly.

Strategies with medium effects change the utility's transition costs by 5% to 25%. Charging wheeling customers for ancillary services results in medium effects on transition costs. Most qualifying-facility contracts incur lower costs for capacity than energy. As a result, discounting qualifying-facility capacity payments to market prices has less effect on a utility's transition costs than does discounting energy payments. Accelerating depreciation of the generation plant may have quite large effects on transition costs, depending on current depreciation expenses and

Table S-1. Potential effects of different strategies on base-case utility transition costs[a]

Potential effect on utility transition costs	Strategy
Large (25% or greater)	Rapidly open retail markets (+)
	Delay retail wheeling (−)
	Market excess energy (±)
	Charge exit fees (−)
	Reduce administrative and general costs (−)
	Discount qualifying facility energy payments to market (−)
Medium (between 5% and 25%)	Increase system load factors (±)
	Accelerate depreciation of the generation plant (+)
	Charge wheeling customers for ancillary services (−)
	Reduce customer-service costs (−)
	Reduce transmission operations and maintenance costs (−)
	Reduce distribution operations and maintenance costs (−)
	Reduce generation operations and maintenance costs (−)
	Discount qualifying facility capacity payments to market (−)
Modest (less than 5%)	Accelerate depreciation of the generation plant and decelerate depreciation of the transmission and distribution plant (+)
	Accelerate depreciation of regulatory assets (±)
	Reduce public-policy-program costs (−)

[a]A "+" indicates the strategy increases transition costs; a "−" indicates the strategy decreases transition costs; a "±" indicates the strategy may increase or decrease transition costs.

the extent to which depreciation schedules are compressed. Because accelerated depreciation raises transition costs, utilities are unlikely to pursue this strategy in isolation.

System load factors can be increased by reducing on-peak demand or increasing off-peak sales. For the base-case utility, reducing on-peak demand lowers utility production costs, but reduces revenue from demand charges even more. The result is an increase in utility transition costs. Increasing off-peak sales increases production costs, but revenue from the higher sales more than offsets the cost increase. The absolute effect of increasing system load factors on transition costs depends on how much load factors change. For most utilities, we expect these changes to be small. As a result, the attendant effects on utility transition costs are unlikely to be much greater than the ones illustrated here, and may indeed be more modest.

Our analysis illustrates that utilities may be able to offset the increased costs of accelerated depreciation by decelerating the depreciation of other assets. Any transition costs remaining will be modest. Accelerated depreciation may also be applied to regulatory assets. Our results suggest that whether accelerating depreciation of these assets increases or reduces utility transition costs depends partly on when the change in depreciation begins. If begun before retail wheeling starts, utility transition costs will decrease. If begun after wheeling starts, utility transition costs will probably increase. If the at-risk utility has substantial above-market generation costs or power-purchase contracts, the effects of regulatory asset depreciation will probably be modest. Accelerating the depreciation of regulatory assets will have a more pronounced effect as these assets' share of total transition costs grows.

Finally, reducing public-policy-program costs will have modest effects on transition costs for most utilities. The ultimate effect, of course, will be determined by the size of the initial programs and the extent of cuts; yet even a utility spending 5% or more of its annual revenues on these programs can hardly expect to achieve large reductions in transition costs. Instead, utilities are motivated to reduce these expenditures to cut prices.

Most of the strategies we examine require the cooperation of other parties, including regulators, to be implemented successfully. As a result, financial stakeholders must be engaged in negotiations that hold the promise of shared benefits. Only by rejecting "winner-take-all" strategies in favor of strategies that benefit multiple stakeholders will the transition-cost issue be expeditiously resolved.

ABBREVIATIONS

A&G	administrative and general
CPUC	California Public Utilities Commission
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
GWh	gigawatt-hour
IPP	independent power producer
kWh	kilowatt-hour
NPV	net present value
O&M	operations and maintenance
ORFIN	Oak Ridge Financial Model
PBR	performance-based rate making
T&D	transmission and distribution

INTRODUCTION

As the restructuring debate in the electricity industry enters its third year, progress is evident on several fronts. The Federal Energy Regulatory Commission (FERC) released a final rule on transmission open access—a key element to facilitate more efficient wholesale markets. Several utilities have already filed transmission tariffs in anticipation of FERC's final rule. 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. 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:

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

Early in the restructuring debate, researchers identified transition costs as a critical issue (e.g., Anderson, Graham, and Hogan 1993). In its initial restructuring proposal, the California Public Utilities Commission (CPUC) also recognized the importance of transition costs (CPUC 1994). The CPUC subsequently held separate hearings on certain transition-cost issues (CPUC 1995a). In the CPUC's final policy decision, only the issue of market structure received more attention than transition costs (CPUC 1995b).

Despite the attention transition costs received in California's restructuring rulemaking, the issue is far from resolved. After releasing its December 1995 decision, the CPUC began to receive requests to rehear the decision. Several of these requests cited transition costs as central to their concern. As an example, Pacific Gas and Electric Company (1996, p. 3) stated:

> To date, the Commission has nowhere undertaken the analytical effort required to assess whether and to what extent the utilities exposed to the various changes in the regulatory framework are likely to recover much or all of their transition costs under the framework adopted, not to mention the costs of developing the new structures envisioned. Such an analysis would be an absolute prerequisite to any finding by the Commission that the ratemaking structure adopted was not unconstitutionally confiscatory in its effect.

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 reduce these costs?
- Who will ultimately pay for any remaining costs and how?

SETTING THE NATIONAL CONTEXT

Uncertainty over the magnitude of potential transition costs clearly contributes to the ongoing debate. One of our earlier studies (Baxter and Hirst 1995) identified industry-wide estimates that ranged from \$20 billion (Hobart 1994) to \$500 billion (Perl 1994). Our study confirmed 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 developed national estimates that ranged from \$16 billion to \$268 billion and suggested that the most plausible range for potential transition costs is \$72 billion to \$104 billion.[1]

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 Moody's because of the treatment of income taxes. Our estimates are net of the change in income taxes.[2] Had Moody's chosen to include the effect of income taxes, their estimate would have fallen in the middle of our most plausible range. These estimates suggest that potential transition costs are substantial, though smaller than many earlier estimates, and that the range of national estimates is narrowing.

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[1]Unless otherwise noted, we express all cost or price estimates in 1994 dollars.

[2]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.

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 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.

Our more recent work examined different estimation approaches. One report identified the broad array of general estimation approaches and examined seven specific approaches in detail (Baxter 1995a). We found that the estimation approaches 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.

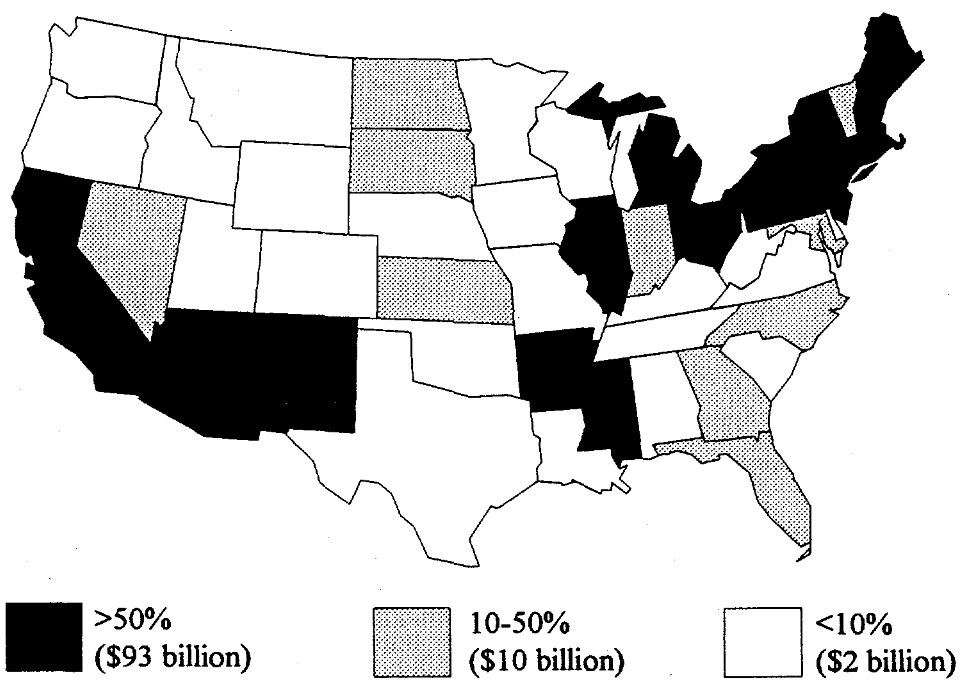

Figure 1. Transition costs as a percent of utility equity (Source: Baxter and Hirst 1995).

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.

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 2 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 (O&M) 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

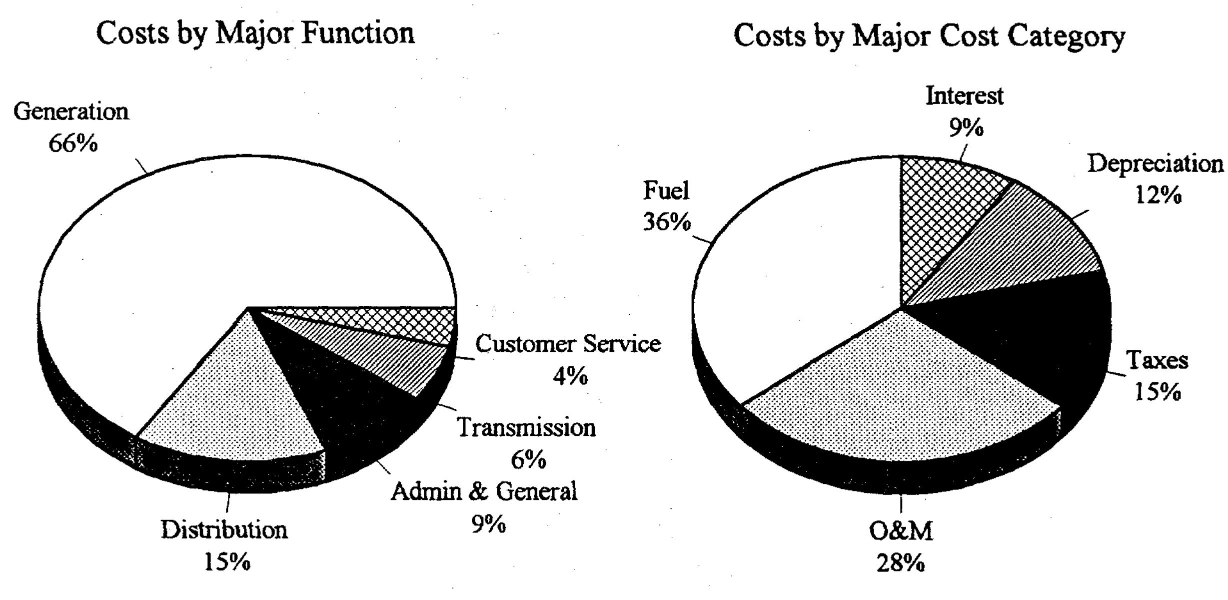

Figure 2. Distribution of costs for U.S. investor-owned electric utilities in 1994 (Source: EIA 1995a). Total costs = $163 billion.

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.

REPORT OBJECTIVES AND OUTLINE

Strategies to address transition costs have emerged from practically every part of the industry. As expected when the potential dollar stakes number in the tens of billions, the array of strategies suggested is substantial, ranging from calls for either the utility shareholders or the utility customers to bear all the transition costs of restructuring. A critical element missing from this debate is information about how specific strategies will affect transition costs. Only with this information in hand, will policy makers and stakeholders be able to identify the more promising strategies and to craft approaches that avoid "winner-take-all" outcomes.

In this report, we have three objectives. First, we identify a wide range of strategies available to regulators and utilities to address transition costs. Second, we systematically examine the effects of selected strategies on transition costs. As one byproduct of this objective, we develop an assessment framework to examine different strategies. Finally, as a result of our initial assessment, we identify potentially promising strategies that may provide benefits to more than one set of stakeholders.

Chapter 2 presents the wide range of strategies for addressing transition costs that we identified in the literature and indicates the strategies we subsequently examined. Chapter 3 describes the assessment framework in detail, including a description of our integrated planning model and the approach we use to assess each strategy. Chapter 4 reports our assessment results. In Chapter 5, we present our conclusions and recommendations.

STRATEGIES TO ADDRESS TRANSITION COSTS

The question of how to address transition costs remains a major impediment to more rapid progress on several other restructuring issues. As a result, regulators, policy analysts, utilities, and consumer groups have proposed a number of strategies to address transition costs. This chapter identifies and describes many of these strategies.

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 reviewed involve shifting costs among different segments of the economy. Costs may shift from one group to another, between electricity consumers and producers, for example, or from future ratepayers to present ratepayers. To mitigate means to relieve, or to make less severe or painful. Characterizing these strategies as mitigation options may be appropriate, so long as we recognize that the relief is often achieved by shifting costs from one party to another.

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, any potential revenue shortfall and resulting transition costs fall on utility shareholders. A simple measure of the transition costs in this case is the difference between the utility's embedded generation costs, as established under traditional regulation, and a generation price that might result from a competitive generation market. Yet at the other extreme—full shareholder recovery of embedded generation costs—ratepayers will experience transition costs as a welfare loss.

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 adjusted 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. In the world of regulatory oversight, of course, these administrative cost savings will probably be shared 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, and these efficiency gains can be used to offset transition costs.

TRANSITION-COST STRATEGIES

From filings at FERC, state proceedings, published literature, industry press, and consultant reports, we compile a list of strategies that may be implemented to address transition costs. Our objective is to reflect the range of ideas being developed for and discussed by the electricity policy community. As a result, we do not screen out proposals that, in our view, are either unsound or politically unpalatable.

Based on our review of these individual strategies, we identify six major types of strategies: market actions, depreciation options, rate-making actions, utility cost reductions, tax measures, and other options. Our discussion of the individual strategies is organized by these six major categories.

Market Actions

These strategies focus on affecting the market structure for electricity or rely on market mechanisms, such as auctions or sales, to affect the distribution of transition costs.

Open Markets. This strategy calls for the rapid and broad opening of retail electricity markets (i.e., retail wheeling) at the earliest possible date. Monopoly franchises for retail electricity sales are eliminated, and all retail electricity purchasers have a choice of electricity suppliers. Such a strategy maximizes competitive pressures on electricity suppliers and results in the maximum consumer welfare gain (Flaim 1994).

Delay Competition. The delay is not indefinite, but this strategy suggests a more deliberate opening of retail electricity markets. Here retail access proceeds in a staged fashion, with only certain customer segments initially getting access to alternate suppliers (Flaim 1994). Retail access is eventually granted to all consumers, but not until several years after the initial group gets access. A variant on this strategy is to give all consumers access at the same time, but to delay the onset of access by several years.

Divest Utility Plant. Divestiture, selling all or part of a utility's generation portfolio to separate companies (affiliated or unaffiliated), is a widely discussed strategy (e.g., Rose 1995a). Divestiture has the potential to address several issues. The sale provides a readily identifiable market value for the asset(s), which is necessary to estimate transition costs, and also separates the unregulated generation business from the regulated transmission and distribution (T&D) business. Some analysts argue that utility divestiture is necessary to ensure competitive markets in some parts of the country and to reduce potential conflicts between unregulated and regulated business operations. Divestiture also reduces the possibility that a utility will exercise market power from a monopoly market (transmission) to a more competitive generation market.

However, divestiture strategies may encounter complex accounting and financial issues (Kinney and Warren 1996).

Rose (1995a) proposes a variant on divestiture, which he calls a "rate-base spin off." Rose's proposal requires a utility to determine the generation needed to serve the retail customers remaining after the onset of competition. The utility retains this portion of its generation and sells the remainder to a separate company. The sale moves that generation out of the utility's rate base, and the separate company becomes an exempt wholesale generator. We do not see a sharp distinction between this option and utility divestiture. In addition, utilities may have difficulty predicting which customers will continue with retail service.

Blank, Gilliam, and Wellinghoff (1996) present another type of divestiture strategy. Under their proposal, the vertically integrated utility is split into two separate companies. The first company is a for-profit, competitive generation company comprised of all the former utility's generation and any necessary transmission assets. The remaining transmission and all the utility's distribution and service functions form a second, nonprofit, company. The nonprofit status of this second company is key to their proposal, as they demonstrate that the ensuing tax (the nonprofit would pay no federal income taxes on its electric operations) and financial savings (higher debt ratings would lead to reduced borrowing costs) can be used to reduce rates or offset transition costs. The nonprofit T&D company would initially contract for generation from the new competitive generation company, but would be free to seek alternative suppliers once this initial contractual obligation is fulfilled. This initial obligation, however, means any transition costs associated with the existing generation system remain with the service territory for the duration of the contract.

A divestiture strategy is most commonly applied to generation, but analysts also discuss the sale of utility transmission assets.[3] This discussion is motivated by the belief that the market value of transmission assets exceeds their book value. In such cases, the above-book proceeds from a transmission sale could be used to at least partially offset the below-book market values of certain generating assets. Setting aside potential legal issues (Hempling, Rose, and Burns 1994), problems arise, of course, for those transmission-poor utilities that are faced with potential transition costs.

Merge. Company mergers are, perhaps, one of the most visible artifacts of the restructuring debate (Wilson 1996). Mergers occur for many reasons, not all of which are related to transition costs. Nevertheless, to the extent that a merger increases overall operating efficiencies or improves marketing opportunities, or both, mergers can be viewed as a transition-cost strategy.

Market Excess Capacity or Energy. Opportunities to increase revenues represent opportunities to reduce transition costs. Marketing existing excess capacity or energy, or capacity or energy freed by departing customers, is a clear strategy to increase revenues. Indeed,

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[3]Revaluing generation, transmission, and distribution assets is a similar strategy, except the utility retains ownership of all assets.

FERC's (1996) transition-cost-estimation approach defines mitigation as the sale of available energy at market prices. Some proposals (e.g., Transmission Access Policy Study Group 1995), including FERC's, give departing customers the opportunity to market energy freed by their departure from the utility.

Depreciation Options

Depreciation expenses for unamortized generation plant contribute directly to fixed generation costs. As a result, analysts have devoted considerable attention to examining how plant depreciation could be modified to address transition costs. The depreciation options we review are all, strictly speaking, rate-making actions. We place depreciation in a separate category to recognize the attention these strategies have attracted in the transition-cost debate.

Accelerate Depreciation of Utility Assets. Traditional regulation permits lengthy depreciation periods for the capital-intensive investments in generating facilities. For large power plants, these depreciation schedules may run over 30 or 40 years. Accelerating a depreciation schedule shortens the time over which capital costs are recovered. All things being equal, accelerated book depreciation increases depreciation expenses over the shortened depreciation schedule, but reduces these expenses once the plant is fully amortized. The primary motivation for accelerated depreciation is to increase the recovery of a utility's fixed costs while its retail franchise is still intact (RDI 1994).

After the utility plant, regulatory assets are often a utility's major asset category. Regulatory assets are intangibles, such as deferred debt costs, that are considered assets because the costs are being collected in rates or because it is probable that costs will be collected in future rates. The regulatory-asset-account balances for many utilities are large, and these assets will have no value in a competitive market. As a result, utilities are requesting accelerated depreciation of regulatory assets in anticipation of increased competition.

Accelerated Depreciation Offset with Decelerated Depreciation. Because accelerated depreciation increases depreciation costs immediately, an alternative is to offset these cost increases by decelerating depreciation of other utility-plant assets (Hempling, Rose, and Burns 1994). For most utilities, the T&D plant is the largest capital asset after generation. Thus, one strategy is to offset the increased costs of accelerated depreciation by decelerating depreciation of transmission or distribution assets, or both. Southern California Edison (1994) proposed such a strategy to more rapidly recover shareholder investment in a nuclear plant and still hold retail rates constant.

Transfer Depreciation Reserves. Transferring depreciation reserves from T&D accounts to generation-plant accounts is an explicit strategy to revalue the associated assets. Such a transfer will reduce the net book value of the generation plant and increase the net book value of the T&D plant by the amount transferred. South Carolina Electric & Gas used this strategy to reduce the net book value of a nuclear plant to the average for nuclear plants in the region (South Caroline Public Service Commission 1996).

Economic Levelization. In some jurisdictions, regulators direct utilities to use a depreciation schedule that creates comparatively higher depreciation expenses in the first years after a plant is added to the rate base. Economic levelization keeps the depreciation expense constant (in real dollars) over time (McCullough and Brown 1994). Thus, economic levelization has the opposite effect of accelerated depreciation and is best described as an indirect transition-cost strategy. This option's objective is to reduce rates so that utilities can compete more effectively for sales.

Rate-Making Actions

Under traditional regulation, authorization to recover generation costs is granted in rate cases. Because rates and embedded cost recovery are so closely connected, it is no surprise that we identify so many transition-cost strategies relying on rate-making actions.

Adjust Utility Returns. Reducing a utility's authorized return will lower earnings, revenues, and rates. However, if the utility is permitted to hold rates constant (i.e., consistent with rates necessary to collect the previously higher earnings), the difference between previous earnings (as embedded in the unchanged rates) and current earnings can be used to reduce transition costs.

Eliminate Subsidies. This and the following two strategies could be described together as "get prices right." Eliminating subsidies means ensuring that rates charged to different customer classes reflect the cost of service for each class. Thus, residential rates are not subsidized by other customers, nor are price discounts for large customers paid by small customers. To the extent these subsidies also distort price signals, eliminating the subsidies provides consumers a clearer indicator of the utility's cost structure relative to alternate suppliers.

Restructure Rates. In most jurisdictions, current rate design recovers variable costs and some portion of fixed costs through a volumetric energy charge. Even for those customers that pay an energy and demand charge, a portion of fixed costs are recovered through the energy charge. Designing a two-part rate for all ratepayers that includes an energy rate close to the utilities' actual marginal costs and a fixed charge close to the utilities' fixed costs represents a more accurate price signal. The utility is able to compete successfully for sales during times when the utility is the low marginal cost provider, thus avoiding uneconomic bypass of the utility's generation system. Valle and Bidwell (1995) note that the lower energy rate that will result for most utilities from such a rate restructuring will also increase electricity demand. Any demand increase will lead to greater revenues and, as a result, reduced transition costs.

Unbundle Rates. Perhaps the simplest example of rate unbundling is the rate-restructuring option described above, which provides more appropriate price signals to consumers. Electricity services and costs can be further unbundled to include T&D costs and ancillary services costs. Unbundling generation services in addition to power delivery, energy, and capacity may help address transition costs. For example, while the costs of ancillary services are a relatively small part of a utility's total costs, charging for these costs may in some cases lead to substantial reductions in transition costs (Baxter 1995a).

Allow Rate Flexibility. Giving utilities more flexibility in setting prices will encourage pricing strategies that affect transition costs (Hempling, Rose, and Burns 1994). With rate flexibility, for example, a utility can charge rates below its embedded cost but above its marginal cost, or even above its embedded costs when the prevailing market price permits.

Performance-Based Rate Making (PBR). PBR eliminates cost-of-service rate making and instead establishes either a price or revenue cap that is adjusted periodically for inflation and a minimum productivity-improvement target. A properly designed PBR mechanism shifts market risks from consumers to the utility, and provides the utility incentives to reduce costs and improve productivity (Commes et al. 1995). PBR is attractive as a transition-cost strategy when at least a portion of these cost savings are credited toward the utility's transition costs.

Rose (1995b), among others, proposed to combine an accelerated depreciation strategy with PBR. In this proposal, the accelerated depreciation costs are offset by cost reductions from the PBR mechanism. Instead of offsetting accelerated depreciation costs for generation by decelerating depreciation of other assets, this option shifts the cost-reduction burden (and risk) to the utility.

Disallow Costs. One strategy to address transition costs is simply to disallow certain costs from rates. These disallowances are related to the utility's above-market generating costs or to other areas of utility operations that regulators deem to be high relative to the industry. In some states, regulators are prohibited from retroactively disallowing costs already in the rate base. In such cases, this strategy is only effective for costs not yet included in rates or that the utility has not yet incurred.

Explicitly Shift Costs to Captive Customers. Regulators can periodically reset rates to recover costs from remaining customers that had previously been paid by departing customers. This strategy is particularly unpopular with utilities who fear a continuous series of rate increases that drive even more customers to other suppliers. Of course, this strategy will be at least as unpopular with captive customers.

Exit Fees. Exit fees paid by departing customers are the opposite of charging captive customers for transition costs. Most, but not all, proposals link the exit fee to those embedded utility costs incurred on behalf of the departing customer (Hempling, Rose, and Burns 1994). Exit fees can be structured as a lump-sum payment or a stream of payments. The exit-fee strategy attracts considerable interest from utilities and regulators, and is the strategy FERC (1996) selected to address transition costs from departing wholesale customers. A properly structured exit fee makes the utility indifferent (with regard to recovering the utility's historical investment on the customer's behalf) to a customer's decision to leave or stay and discourages uneconomic bypass of the utility's system.

Net Generation Savings. Rose (1995a) discusses a strategy of sharing the generation savings realized by departing customers. This is also a type of exit fee, but the fee is discounted. Rose defines the full generation savings as the difference between the utility's embedded cost of generation and the generation price obtained by the departing customer. Only a percentage of the full generation savings realized by the departing customer is used to offset transition costs. The customer keeps the remaining savings.

Access Charges. Access charges for transmission or distribution service can be structured to include transition cost recovery. The access charges are fixed ($/customer) or volumetric [¢/kilowatt-hour (kWh)]. The fixed charges are collected as a lump sum or as a payment stream. Charges set for transmission access are under FERC jurisdiction, while charges for distribution access are under state jurisdiction. Access charges are appealing because they recover transition costs from all electricity users except those few that are completely disconnected from the utility grid. Rose (1995a) describes an access charge that applies only to departing customers. This option resembles an exit fee, except that the access charge is tied to a continued service provided by the utility seeking to recover costs from the departing customer.

Utility Cost Reductions

As with depreciation options, utility cost-reducing options could also be categorized as rate-making actions. To be considered as fully realized transition-cost strategies, most of the following options require regulatory approval to allow cost reductions, particularly those achieved in nongeneration operations, to be used to offset transition costs. Generation cost savings directly reduce transition costs by allowing utilities to offer more competitive electricity prices. Cost reductions that do not lead to reductions in the quality or level of service provided represent economic-efficiency gains, and thus are distinguished from strategies that shift costs among different economic actors.

A decision by the Arizona Corporation Commission (1996) contains an example of one type of cost-reducing mechanism that can be applied to the first three strategies listed below. Cost reductions that the Arizona Public Service Company achieves in relation to an established benchmark are to be shared between ratepayers and shareholders.

Reduce Operating Costs. Generation costs savings could come from reducing plant heat rates and O&M costs and from retiring uneconomic plants. Utilities would be motivated to reduce costs in other areas, such as transmission, distribution, and customer service, if these reductions decrease transition costs for shareholders.

Reduce Public-Policy-Program Costs. By public-policy programs, we refer to the collection of obligations vested in utilities by legislators and regulators (Tonn, Hirst, and Bauer 1995). These obligations include energy-efficiency, low-income, and research-and-development programs, among others. From the utility's perspective, the primary benefit of reducing public-policy-program costs is to reduce overall costs and prices.

Reduce Power-Purchase Costs. Utilities with above-market power-purchase contracts, whether with qualifying facilities (QFs), independent power producers (IPPs), or other utilities, can reduce costs by restructuring these contracts. Depending on the history of the specific contract and the utility's financial status, the utility may be able to restructure the contract, or to buy out the above-market portion of the contract at a discount.

Financial Write-Downs. By taking a financial write-down of assets, the utility may take a loss against income. Assuming the plant is no longer operating and is not fully depreciated for tax purposes, this loss would be shared with taxpayers at the utility's marginal tax bracket. Under a write-down, further capital cost recovery is no longer probable as required by Financial Accounting Standards No. 71 (Financial Accounting Standards Board 1982). Proponents argue that this approach is most appropriate for assets developed or deployed in response to federal policy because any reductions in tax collections are experienced by the U.S. Treasury.

Tax Measures

Taxes are used frequently as an instrument of public policy. Because the economy's electricity sector provides substantial tax revenues at the federal, state, and local level, we are not surprised to identify several transition-cost strategies that rely on tax measures. Tax strategies appeal to those who argue that the entire economy benefits from restructuring the electricity sector and that, as a result, the entire economy should bear any transition costs. In addition, spreading transition costs over the entire economy reduces the effects on any single sector. Of course, policies that increase taxes have fallen into disfavor in the United States.

Consumption Tax. This is a broad-based tax on electricity use (¢/kWh or a fixed percentage of the sale price), implemented at the state or federal level. The revenues from a consumption tax would be distributed to utilities facing transition costs. Several options are available to structure this strategy. The annual revenues could be directed into a trust fund (or funds in different states) administered by a public agency. The fund(s) could then subsidize the buy out of above-market utility and independent generation and regulatory assets. We estimate that such a tax at the national level would be 0.5¢/kWh, as a rough approximation, and would need to remain in effect for ten years.[4]

National Tax for Nuclear Plants. This strategy is simply a consumption tax targeted to pay for transition costs associated with nuclear plants, including their unrecovered sunk costs, waste storage, and plant decommissioning (Working Group 1995). This strategy is favored by those arguing that federal policies played a substantial role in the development and deployment of commercial nuclear electricity generation.

Production Tax. A production tax is an excise tax imposed on electricity sales or generation and levied on electricity generators rather than consumers (Rose 1995a). Most excise taxes, such

[4]We assume the present value of industry-wide transition costs is $100 billion. Collecting this sum over ten years requires constant annual payments of about $15 billion, assuming an 8% discount rate. National electricity use was about 2.9 million gigawatt-hours (GWh) in 1994. Assuming an annual growth of 2%/year, average annual national electricity use over the ten-year period would be about 3.2 million GWh. Dividing $15 billion by 3.2 million GWh yields about 0.5¢/kWh.

as those on cigarettes, alcohol, and gasoline, are shifted to consumers by including the amount of the tax in the selling price. The primary difference between the consumption and production tax proposals is who collects the revenue from the taxes, and not who ultimately pays.

Tax Reduction. A tax-reduction strategy can take many forms. This strategy was initially conceived as a reduction in the utility's marginal income tax rate at the state (where applicable) or federal level. However, a tax reduction can also target a state's gross revenue tax collected by the utility. Because independent producers do not collect this tax, a gross revenue tax acts to further differentiate utility prices from prices of alternate suppliers. Where utilities pay proportionately greater property taxes than other generators, equalizing property tax rates also reduces the difference between utility prices and prices from independent generators.

Tax Deduction. This strategy calls for a tax deduction or credit for uneconomic and unamortized investments in utility plant that utilities subsequently retire (Working Group 1995). Such a deduction is beyond the deduction from the loss of income that a utility takes as a result of writing down generating assets to market.

Other Options

Preserve Retail Franchise. Some have argued for preserving the retail franchise as a transition-cost strategy (e.g., Steinmeier 1995). Except as another way of delaying or eliminating competition, it is difficult to see how this strategy addresses transition costs.

Eliminate Obligation to Serve. Certain early restructuring proposals did not relieve utilities from their historical obligation to serve all customers within their franchise service areas. If utilities no longer face this obligation for departing customers, utilities may be more able to retire uneconomic assets or reduce capacity reserve margins.

Statutorily Authorized Recovery. Legislators can enact laws that convert a regulatory promise of cost recovery into a statutory right to recovery. Puget Power implemented this strategy to ensure recovery of utility demand-side-management expenditures—the utility's largest regulatory asset (Kelly and Gaines 1995). The specific statute enacted in Washington creates a new property right, the "bondable conservation investment." Under this law, customer rates must be allowed to recover demand-side-management-related expenditures, including the costs of project financing, once these costs are approved by state regulators. Once this revenue stream is secured, it may be used as the basis for issuing securities, that in turn may be used to obtain lower-cost financing.

Entrance Fee for Returning Customers. Customers that depart the utility system but subsequently elect to return can be charged an entrance fee. The entrance fee could be structured to cover the transition costs incurred during the period the customer purchased from alternate suppliers.

Entrance Fee for New Generation. Generation developed after restructuring can be charged a fee to enter the market (Rose 1995a). The rationale for this strategy is that new generators benefit more than existing generators from competitive markets. Setting aside that its underlying rationale is open to dispute, this proposal appears to face several obstacles. Deciding which agents will collect this fee is difficult. Transmission-owning and distribution-owning utilities are likely candidates, but using these agents encourages abuse of their market power. Moreover, those utilities collecting the fees are not necessarily those with transition costs. More importantly, new generators were never subject to the traditional regulatory compact and, therefore, did not cause or contribute to any transition costs flowing from that compact. Finally, an entrance-fee approach raises barriers to new entrants to the generation market, which is entirely inconsistent with prevailing restructuring proposals.

WHO BEARS THE TRANSITION COSTS?

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 PBR 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.

Of the 34 strategies we identify, retail ratepayers have primary or secondary responsibility for paying transition costs in 19, shareholders in 12, wheeling customers in 11, taxpayers in 8, and nonutility suppliers in 4. 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 comprehensive restructuring 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 shareholders, retail ratepayers, and 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 may be hurt when the utility does not pursue profitable wholesale-market opportunities. Shareholders will be hurt because of the foregone margins from the wholesale market. Retail ratepayers will face higher rates if the utility operates generating units when cheaper wholesale power is available for purchase. As we show in Chapter 4, however, utility shareholders may sometimes incur lower losses if the utility does not increase wholesale sales in response to retail wheeling.

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. Economic levelization does the opposite. 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 reserve 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.

Unbundling rates allocates some costs to wheeling customers, for example, should they continue to pay for ancillary services or nongeneration-related customer services and administrative and general (A&G) expenses. A variant of the access-charge strategy shifts transition costs to wheeling customers, though the more frequently discussed 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. The utility may also then be permitted to charge entrance fees for returning customers. 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

Table 1. Who bears the transition 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					
Accelerate depreciation		✓			
Accelerate/decelerate depreciation		✓			
Transfer depreciation reserves		✓		✗	
Economic levelization		✓			
Rate-Making Actions					
Adjust utility returns	✓		✗		
Eliminate subsidies		✓			
Restructure rates		✓			
Unbundle rates		✓		✗	
Allow rate flexibility		✓			
Performance-based rates	✓	✗			
Disallow costs	✓		✗		
Explicitly shift costs to captive customers		✓			
Exit fees				✓	

Strategy	Utility Shareholders	Retail Ratepayers	Taxpayers	Wheeling Customers	QFs, IPPs
Net generation savings	✓			✓	
Access charges		✓		✓	
Utility Cost Reductions					
Reduce operating costs	✓	✓			
Reduce public-policy-program costs[c]					
Reduce power-purchase costs	✓				✓
Financial write-downs	✓		✗		
Tax Measures					
Consumption tax		✓		✓	
National tax for nuclear plants		✓		✓	
Production tax	✗	✓		✓	✗
Tax reduction			✓		
Tax deduction			✓		
Other Options					
Preserve franchise		✓			
Eliminate obligation to serve	✓		✗		
Statutorily authorized recovery		✓		✓	
Entrance fees for returning customers				✓	
Entrance fees for new generation				✗	✓

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

STRATEGIES ASSESSED

Of the 34 strategies discussed in this chapter, we selected several for quantitative examination based on three criteria: the availability of data to characterize the strategy; the suitability of our assessment framework to examine the strategy; and the electric-industry community's interest in the strategy as evidenced by an approach's prominence in filed testimony and the wider literature.

We examined reasonably complete representations of ten strategies and partial representations of two others. We examined one of these 12 strategies, reducing utility operating costs, in detail, studying four separate areas of utility cost performance and cost-reduction potential. The 12 strategies selected for analysis were:

- open retail markets;
- delay competition;
- merge (e.g., improve utility load factors);
- market excess power;
- accelerate depreciation of generation plant;
- accelerate depreciation of generation plant and decelerate depreciation of T&D plant;
- accelerate depreciation of regulatory assets;
- unbundle rates (e.g., charge departing customers for ancillary services);
- exit fee for departing customers;
- reduce operating costs;
    - reduce customer-service costs;
    - reduce A&G costs;
    - reduce T&D O&M costs;
    - reduce generation O&M costs;
- reduce public-policy-program costs; and
- reduce power-purchase costs.

The assessment framework used to investigate these strategies is described in Chapter 3.

ASSESSMENT FRAMEWORK

This chapter describes our integrated utility planning model—the Oak Ridge Financial Model (ORFIN) and how we apply the model to assess different strategies. It also presents details about the base-case utility and the retail-wheeling scenario. In addition, it describes how we estimate benchmarks for different aspects of industry performance.

FRAMEWORK OUTLINE

We use ORFIN to assess the effects of different strategies on transition costs. We have used ORFIN in several other applications, such as assessing the effects of different resource additions on utility shareholders (Hirst and Hadley 1994a), studying the effects of demand-side management programs on utility rates (Hirst and Hadley 1994b), examining the consequences of net lost revenue adjustment mechanisms on utility finances (Baxter 1995b), and analyzing the effects of different transition-cost-estimation methods (Hirst, Hadley, and Baxter 1996a).

For most strategies, we follow three steps. The first step is to define a base-case utility—the reference point for our assessment. The financial effects of retail wheeling and the strategies to address the ensuing transition costs are estimated with reference to this base case. The second step is to create a retail-wheeling scenario and then estimate the financial consequences of retail wheeling on the utility shareholders. We hold retail prices constant from the base case so that utility shareholders bear the transition costs.[5] The third step is to incorporate a strategy into ORFIN and estimate the resulting financial consequences.

These three steps in the assessment framework are diagramed in the upper half of Figure 3. They result in two estimates of transition costs. One estimate reflects the financial effects of imposing the retail-wheeling scenario on the base-case utility. The other estimate reflects the financial effects of imposing the transition-cost strategy on the retail-wheeling scenario. Our estimate of each strategy's effect is the difference in estimated transition costs between the retail-wheeling scenario and the retail-wheeling scenario with the strategy. For the example in Figure 3, we estimate the strategy reduces transition costs to utility shareholders by $300 million. Unless otherwise noted, this is the approach we use to assess each strategy.

[5]We have also examined the financial consequences of retail wheeling on remaining ratepayers (Hirst, Hadley, and Baxter 1996b). For most of the cases we studied, the magnitude of transition costs were similar, regardless of whether all costs fell on shareholders or ratepayers. The important exception was the amount of retail load that is eligible for wheeling. We also examined the sensitivity of transition-cost estimates to a wide variety of market, regulatory, and accounting factors, including production costs, market prices, load growth, and fuel prices.

For a few of the strategies examined, this framework is not appropriate. As an example, consider a strategy of cutting public-policy-program costs. Here we assume that the cost reduction is accompanied by a reduction in services offered. In this circumstance, regulators will not allow the utility to continue to charge rates that were initially set to include the prior level of program costs and services. For this and other strategies where it is not reasonable to assume that retail prices remain constant from the base case to the retail-wheeling scenario, we proceed by defining a new base-case utility. Here the strategy is introduced when we define the new base-case utility. The new base case includes a new estimate of retail rates that reflect the utility's new cost structure. We then introduce the retail-wheeling scenario to the new base-case utility.

The lower half of Figure 3 illustrates this alternative framework. As before, the result is two estimates of transition costs; but in this approach, the second estimate is made with reference to the new base-case utility. Our estimate of the effect of the strategy is still the difference in estimated transition costs between the retail-wheeling scenario and the retail-wheeling scenario with the strategy. The example in Figure 3 indicates this difference is $50 million.

THE OAK RIDGE FINANCIAL MODEL

ORFIN is a simplified version of a utility integrated planning model. ORFIN includes a production-costing module, utility financial statements (income statement, balance sheet, and cash-flow statement), and a rate-design module (functionalization, classification, and allocation of costs to customer classes). Hadley (1996) provides the most complete description of the version of ORFIN used in our current study.

Before briefly describing the elements of ORFIN most relevant to this study, we first define the boundaries of our assessment framework, which are illustrated in Figure 4. ORFIN simulates a single utility interacting with a single wholesale market. The utility serves bundled retail customers through its integrated generation, transmission, and distribution system. The utility also buys and sells power on the wholesale market when economical, subject to certain system constraints, such as the utility's wholesale transmission capacity. Wheeling customers purchase electricity directly from the wholesale market but receive electricity through the utility's T&D network.

ORFIN contains many user inputs to permit examination of the effects of a wide variety of variables on utility production costs, assets, incomes, losses, and rates. Table 2 lists the key categories of user inputs. The user provides information on the initial state of the utility. These initial conditions include information on the utility's power plants, power-purchase contracts, O&M costs, and customer characteristics. The user also specifies the initial fuel prices and wholesale prices and their escalation over time. This initial state of the utility defines the base case.

The dispatch module uses data from each year to calculate the generation, contract purchases, and wholesale-market activity (purchases and sales) for the utility. The module dispatches up to

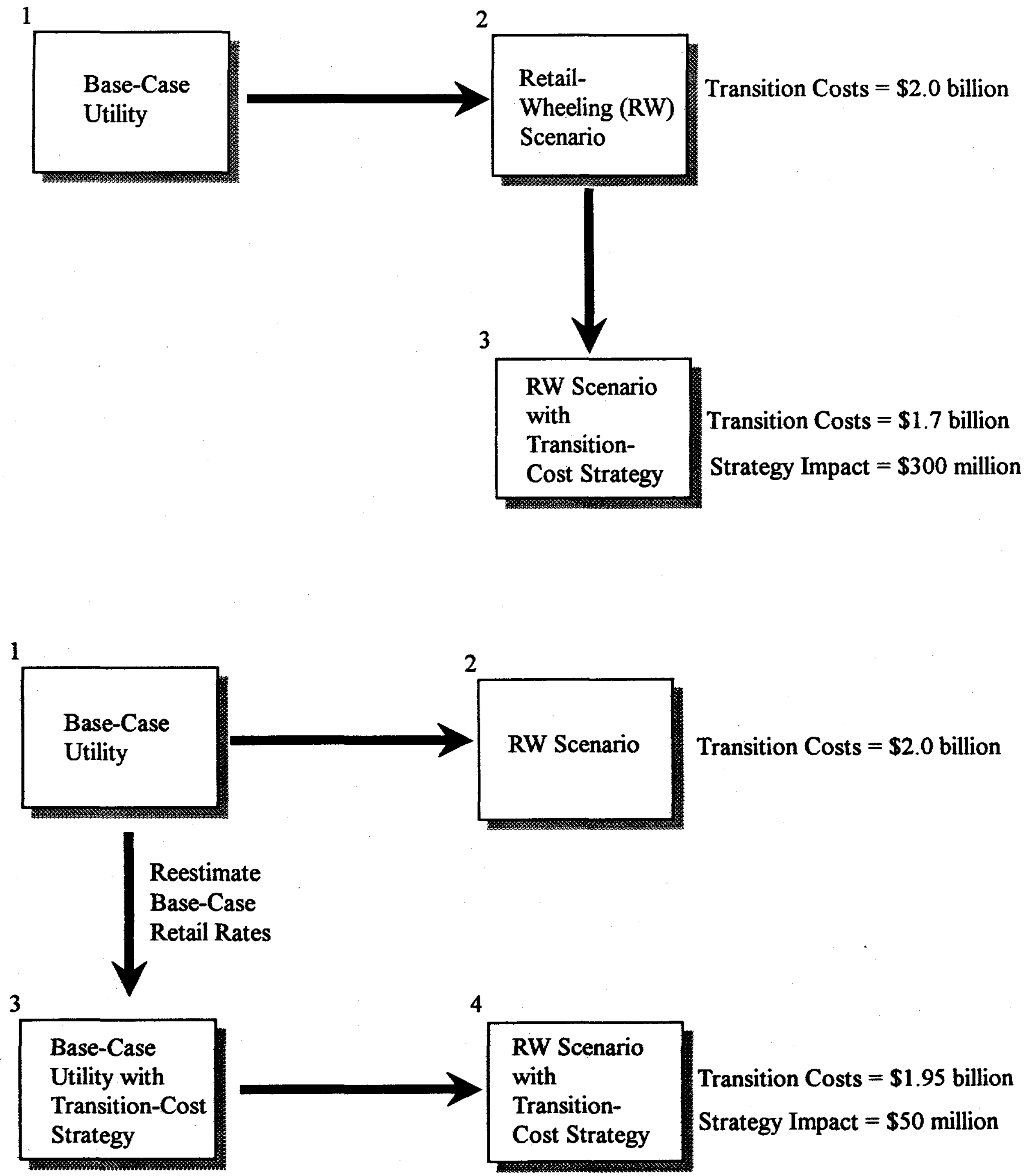

Figure 3. Steps in the assessment of transition-cost strategies.

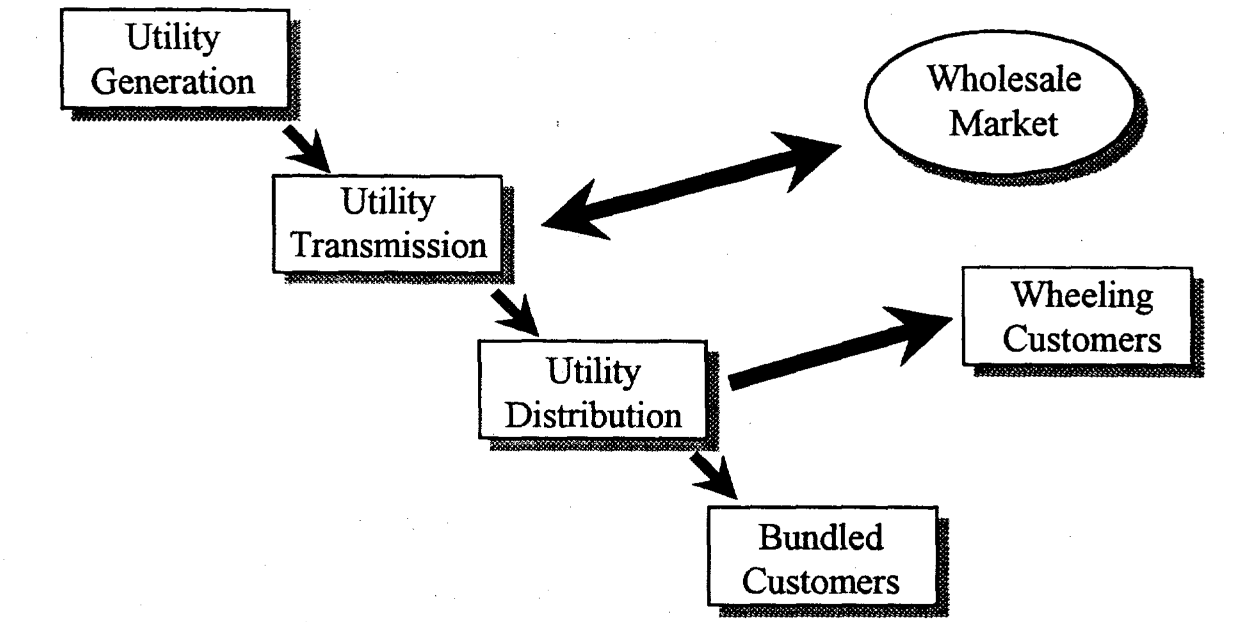

Figure 4. Schematic of the assessment modeling framework.

ten distinct utility resources. These resources can be utility-owned generating units, long-term power-purchase contracts, or a new resource (a utility-owned plant or a contract). New plants may be added in small increments each year to ensure that the utility meets its designated reserve requirements. The model matches production and loads for a peak period (that includes no planned outages) and an off-peak period (where plants are derated so that their annual availability accounts for user-defined forced and planned outage rates). The production-costing results are then used by the financial portions of ORFIN to estimate O&M expenditures.

The dispatch module first calculates load-duration curves for the peak and off-peak seasons. The ten resources are then sorted in order of their variable costs. Must-run plants are assigned a zero bid price for dispatching purposes. The percentage of the season a plant operates is calculated for up to 22 power levels. For each season, these 22 points are sorted by increasing power level before calculating the equivalent load duration curve for each plant.

After calculating the operating times for all plants for the year, ORFIN determines if it is economical to sell any excess power on the wholesale market or to displace some of its own production with wholesale purchases. The user defines the wholesale market using up to four wholesale prices for different portions of the year. ORFIN then compares the variable cost for each plant with the wholesale purchase and sale prices for each period. When a plant's variable cost is lower than the current wholesale sale price and the plant has excess capacity, the plant will sell into the market. When its variable costs exceed the wholesale purchase price and it is producing at that time, then ORFIN backs down the plant and, instead, purchases wholesale

Table 2. Key inputs to ORFIN

Nongeneration operating costs
Transmission, distribution, customer service, A&G, O&M ($/year), and public-policy-program costs ($/year), and O&M cost escalation (%/year)

Nongeneration capital costs
Transmission, distribution, and general capital costs ($/year, $/customer, $/ΔkW)

Power-purchase contracts
Capacity (MW), offline date (year), forced and planned outage rates (%), fixed costs ($/kW-year), and variable costs (¢/kWh)

Utility-owned generating units
Capacity (MW), initial cost ($/kW), start and offline dates (year), tax and book depreciation lives (years), forced and planned outage rates (%), fixed O&M cost ($/kW-year), variable O&M cost (¢/kWh), O&M escalation rate (%/year), heat rate (Btu/kWh), fuel type, and fuel prices ($/MBtu) by year

Wholesale-market prices
Prices (¢/kWh) by time period (% of year), escalation rates (%/year), difference between wholesale purchase and sale price (¢/kWh), and transmission capacity (MW)

Customers
By class: number of customers, consumption (kWh/customer-month), load factor, growth rates (%/year) in number of customers and in per-customer consumption, and T&D energy and demand losses

Retail wheeling
Percentage of customers from each class that wheel by year, percentage of A&G costs paid by wheelers, and ancillary-service cost adder (¢/kWh)

Finances
Long-term bonds and common equity (% of total capitalization and return in %/year), inflation rate (%/year), federal/state income tax rate (%), revenue-sensitive tax rate (%), property tax rate (%), frequency and type (historic vs future test year) of rate cases, and regulatory assets

power. ORFIN compares each possible transaction with the user-defined transmission-capacity constraint and limits wholesale sales and purchases accordingly.

ORFIN's income statement reflects the results of the utility's operations for a calendar year. The income statement includes detail about revenues, expenses, and income. Income is the difference between revenues and expenses. Revenues are the product of electricity sales and prices, summed over the relevant customer classes. Operating expenses include production and nonproduction costs, book depreciation, taxes, and interest payments. Production expenses include fuel and O&M costs for the utility's power plants, power-purchase-contract costs, and purchases and sales on the wholesale market. Net income is the return to utility shareholders. ORFIN yields what is called a bottom-up ex ante administrative valuation of transition costs

(Baxter 1995a). The annual transition costs are the annual difference in net income between the retail-wheeling scenario and the base case. The total transition costs are the sum of these annual differences, discounted to present value dollars.

$$\text{Net Income}_t = \text{Revenues}_t - \text{Expenses}_t$$

$$\text{Transition Costs} = \sum_{t=1}^{T} \left[(\text{Net Income}_{bc,t} - \text{Net Income}_{rw,t}) \div (1 + d)^t\right]$$

We calculate transition costs as net present value at the utility's return on equity for the years t = 1 through year T. In our analysis, the utility's nominal return on equity is 11%, which, when combined with a 3% inflation rate, yields a real discount rate, d, of 8%. We also set T = 10 for most strategies. In practice, determining T can be difficult because, under certain circumstances, the annual values calculated with the second equation may be positive for a few years and then turn negative. Net $\text{Income}_{bc,t}$ is from the base case for year t while Net $\text{Income}_{rw,t}$ is from the retail-wheeling case for the same year.

Base Case

To assess transition-cost strategies, we develop a hypothetical base-case utility. We select an existing utility to serve as the template for the base case. As a result, the base case is developed from a substantial amount of actual utility data from 1993 and 1994. In deciding which existing utility to use as a template, we select a utility that faces potentially substantial transition costs arising from each of three major transition-cost categories: utility-owned generation, power-purchase contracts, and regulatory assets. The actual utility data we use to develop the base case are from an industry-wide data base (RDI 1995), the utility's annual reports and resource plan, and the utility's Section 10-K filings with the Securities and Exchange Commission. In our base case and subsequent analyses, our objective is not to precisely simulate the performance of a specific utility.[6] Instead, we ground our analysis with actual data whenever possible to make our assessments more concrete.

As of 1995, the base-case utility is investor-owned with a rate base of $7.3 billion, common equity of $3.2 billion, and revenues of $4.6 billion. Annual retail sales are 43,800 GWh, and retail peak demand is 7,500 MW. In the absence of retail wheeling, the utility forecasts annual electricity sales and peak demand to grow at about 1.0%/year. The utility's system load factor is 66%.

The utility's total generating capacity is 10,000 MW (Figure 5). The utility owns about 52% of this capacity, including a large nuclear plant (1,270 MW). The remaining capacity consists of long-term power-purchase contracts. All the long-term contracts are in effect through the 10-year analysis period. Roughly two-thirds of these long-term contracts (approximately 3,100 MW) are

[6]We multiply key utility-specific data (e.g., capacity and loads) by a scalar to create the hypothetical utility in our base case.

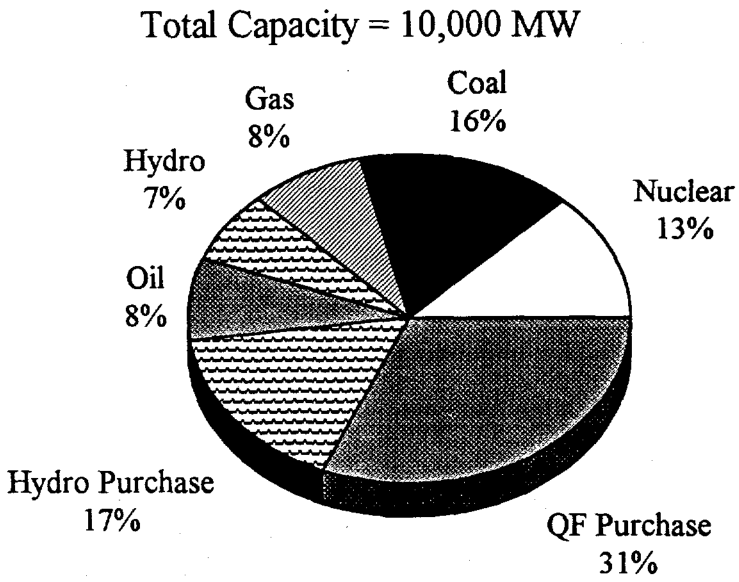

Figure 5. Generation mix for the base-case utility.

with QFs. Nearly 90% of the QF contracts (about 2,800 MW) have "must-run" provisions; that is, the utility must purchase power from these facilities when they are available. We model these must-run provisions by setting their bid price at zero for plant-dispatch purposes. The combined capacity and energy payments for these must-run contracts result in purchased electricity at about 7.2¢/kWh. With a reserve margin of 33%, the utility has no plans to add new resources. The utility's large coal plant (1,570 MW), one of its natural gas plants, and all of its hydro plants (725 MW) are fully depreciated. The nuclear plant is a comparatively recent addition to the utility's rate base and will not be fully depreciated until 2018. The utility's regulatory-asset-account balances total about $1 billion in 1995.

Because the utility has surplus capacity, substantial transmission links (3,600 MW) with neighboring systems, and low marginal generation costs (an average of about 2.1¢/kWh), the utility is active on the wholesale power market.[7] The utility sells about 9,400 GWh into the wholesale market and purchases about 1,000 GWh. Wholesale sales decline about 4%/year, and purchases increase about 9%/year as the utility's retail sales increase over time.

We characterize the wholesale market using four price blocks. Purchases from the four blocks are available 30%, 30%, 35%, and 5% of the time, respectively. The purchase prices from the blocks are 2.0¢/kWh, 2.2¢/kWh, 2.4¢/kWh, and 6.0¢/kWh, respectively. We assume that

[7]Note that the must-run QF contracts reduce the utility's marginal generation costs. The must-run plants effectively push the utility-owned plants further up the dispatch order. As a result, the utility's coal plant (variable costs of 1.7¢/kWh) and one of its natural gas plants (variable costs of 2.2¢/kWh) are on the margin for substantial hours of the year. The overall capacity factor for utility-owned generation in 1995 is 0.58, while the power-purchase capacity factor is 0.61.

wholesale sale prices are 0.1¢/kWh lower than the purchase prices for each block. We expect wholesale sale prices to be less than purchase prices because the utility has to pay for losses or other ancillary services when selling power on the wholesale market. We assume the base-case utility is a price-taker in this market and that its purchases from and sales to this larger market have no effect on market prices. We use three sources to develop this characterization of the wholesale market. First, we examine system lambda data from the relevant regional power pool in conjunction with hourly load data for the template utility. Second, we consult a wholesale market forecast for this region (Coste and Adams 1994). Finally, we consider personal communications with utility staff about the price and supply characteristics of the wholesale market in their area. These three sources provide a consistent characterization—current wholesale prices are low for most of the year, though for a few hundred hours each year prices can become substantially higher, and purchase and sales opportunities are abundant.

In estimating rates for the base case, we ensure that the utility collects revenues sufficient to recover all costs, including the utility's authorized 11% return on equity. Full-service retail customers face these same rates in the retail-wheeling scenario. Residential customers pay a volumetric rate and a customer charge. Commercial and industrial customers pay a volumetric rate, a demand charge, and a customer charge. As Figure 6 illustrates for 1994, the utility's average residential rates (12.4 vs 8.4¢/kWh), commercial/industrial rates (9.9 vs 6.1¢/kWh), and total production costs (5.7 vs 4.5¢/kWh) are substantially higher than national averages for

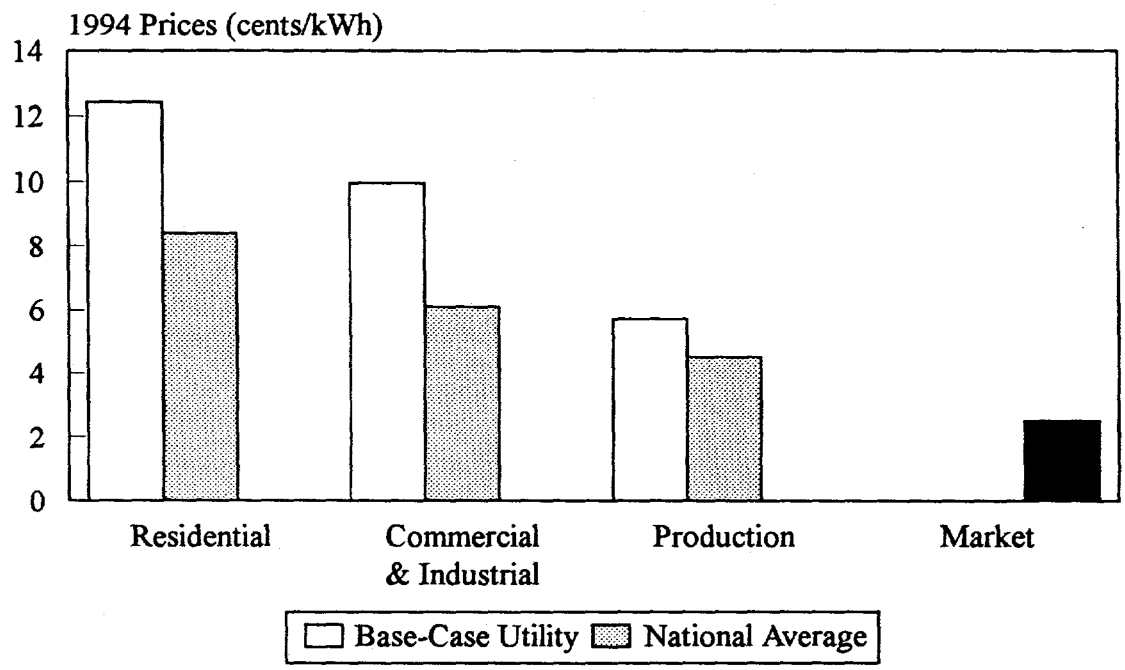

Figure 6. Comparison of base-case and national-average electricity prices for 1994.

electric utilities (EIA 1995b). Most importantly for potential transition costs, the utility's average production cost is well above the average wholesale price (2.5¢/kWh, weighted by consumption).

We assume modest inflation (3%/year), no real increases in fuel prices, no new generating units under construction, no investments in existing generating units, but new investments in transmission ($86 million/year) and distribution ($164 million/year). The utility's assets decline from $7.3 billion in 1995 to $7.0 billion in 2005 (in nominal terms). Utility production costs (i.e., O&M and fuel costs) remain constant in real terms. As a consequence of the depreciation of utility assets, by 2005 real average production costs and retail rates decline to 4.2¢/kWh and 9.2¢/kWh, respectively. Table 3 provides a summary of the base-case-utility results.

Retail-Wheeling Case

We assume retail wheeling begins in 1996 for commercial and industrial customers and 1997 for residential customers. By 1998, 60% of commercial and industrial customers have alternative suppliers, as have 40% of residential customers by the year 2000. These assumptions about the timing and pace of retailing are developed exogenously and then incorporated in ORFIN. We then hold these wheeling percentages constant so that these same fractions of new customers (60% commercial and industrial, 40% residential) entering the utility's former service area become wheeling customers. Figure 7 depicts the shift to wheeling under this scenario. The scenario reflects an aggressive move by utility customers to obtain alternative suppliers. As

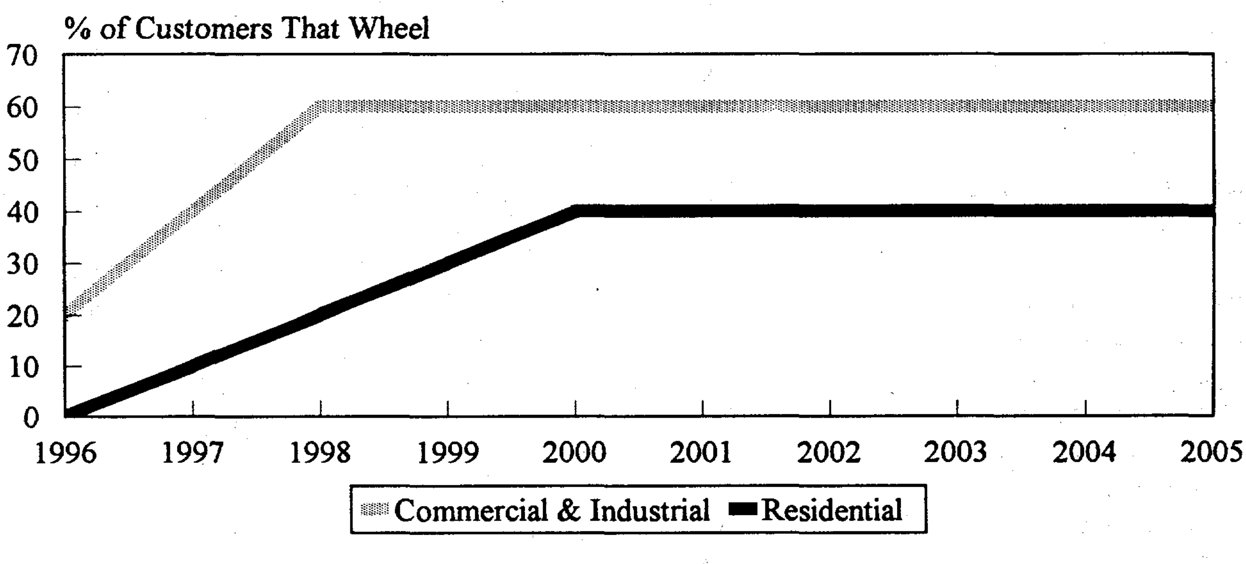

Figure 7. Retail-wheeling scenario.

Table 3. Summary information from ORFIN for the base-case utility

	1995	1996	1997	1998	1999	2000	2005
ANNUAL SUMMARY							
Retail sales (GWh) at busbar	43,809	44,274	44,744	45,220	45,700	46,187	48,700
Wholesale (spot) sales (GWh)	9,424	9,070	8,713	8,361	8,012	7,666	5,992
Wholesale (spot) purchases (GWh)	-1,020	-1,129	-1,242	-1,364	-1,494	-1,634	-2,471
Net wholesale GWh	8,404	7,940	7,471	6,997	6,517	6,033	3,521
Retail wheeling	0	0	0	0	0	0	0
Peak demand at busbar (MW)							
Retail	7,522	7,603	7,685	7,768	7,852	7,937	8,376
Wholesale sales	1,941	1,897	1,853	1,810	1,766	1,722	1,493
Wholesale purchases	680	707	721	742	770	801	906
Retail wheeling	0	0	0	0	0	0	0
Costs and prices (1994 ¢/kWh)							
Average retail price	10.98	10.76	10.54	10.33	10.14	9.95	9.19
Average production costs							
Fixed	2.82	2.64	2.46	2.30	2.14	2.00	1.44
Variable	2.82	2.81	2.81	2.80	2.80	2.79	2.76
Total	5.64	5.45	5.27	5.10	4.94	4.79	4.20
Average marginal cost of generation	2.07	2.11	2.16	2.21	2.26	2.31	2.56
Wholesale price to meet demand	2.49	2.49	2.49	2.49	2.49	2.49	2.49
Return on equity (%)	11.00	11.00	11.00	11.00	11.00	11.00	11.00
INCOME STATEMENT (millions, nominal $)							
Revenues	4,615	4,705	4,799	4,898	5,001	5,110	5,767
Expenses							
Fuel	287	295	304	313	323	332	385
Power-purchase contracts	1,405	1,438	1,473	1,508	1,545	1,583	1,789
Spot purchases	36	41	45	50	56	62	102
Spot sales	-196	-194	-191	-189	-186	-183	-164
Purchased power, total	1,245	1,285	1,326	1,370	1,415	1,462	1,726
O&M, fixed + variable	254	262	270	278	286	295	342
Production expenses, total	1,786	1,842	1,900	1,961	2,023	2,089	2,453
Nonproduction expenses	854	884	914	946	978	1,012	1,199
Book depreciation	231	235	240	245	251	256	283
Depreciation of regulatory asset	91	91	91	91	91	91	91
Revenue-sensitive taxes	462	470	480	490	500	511	577
Property taxes	317	319	322	325	328	331	350
Federal income taxes, current	201	197	193	189	186	185	265
Federal income taxes, deferred	35	35	35	35	35	33	-49
Expenses, total	3,977	4,074	4,176	4,281	4,392	4,507	5,169
Interest expense	284	282	281	280	278	277	275
Net income	355	349	343	337	331	326	323
BALANCE SHEET (millions, nominal $)							
Assets	7,269	7,229	7,192	7,160	7,132	7,107	7,053
Equity	3,196	3,141	3,088	3,036	2,987	2,942	2,963

noted earlier, we also assume that retail rates are the same in the base case and the retail-wheeling case. As a result, the revenue losses from retail wheeling are borne by utility shareholders. We assume that wheeling customers pay a wheeling charge that includes the nongeneration portion of A&G costs. Wheeling customers also pay customer service and T&D costs.

Table 4 presents the effects of wheeling on the utility by showing the differences between the base-case (i.e., Table 3) and retail-wheeling-case values. Utility retail sales drop by 24,700 GWh in the year 2000. The utility quickly eliminates wholesale purchases, but dramatically increases sales to the wholesale market. By the year 2000, the utility has increased sales about 0.9 kWh on the market for every 1.0 kWh in lost retail sales. The utility's production costs increase markedly under retail wheeling, from 5.6¢/kWh in 1995 to 7.6¢/kWh in 2000. Fixed costs per retail sale in particular show a dramatic increase as these costs are spread over a declining customer base.

The utility's loss of net income is $137 million in 1996 and peaks at $527 million in 2000 before declining gradually to $510 million by 2005 [in nominal terms (Figure 8)]. The total transition costs are $2.45 billion under the retail-wheeling scenario [1996–2005, net present value (NPV)], which represents 77% of the utility's equity as of 1995.[8]

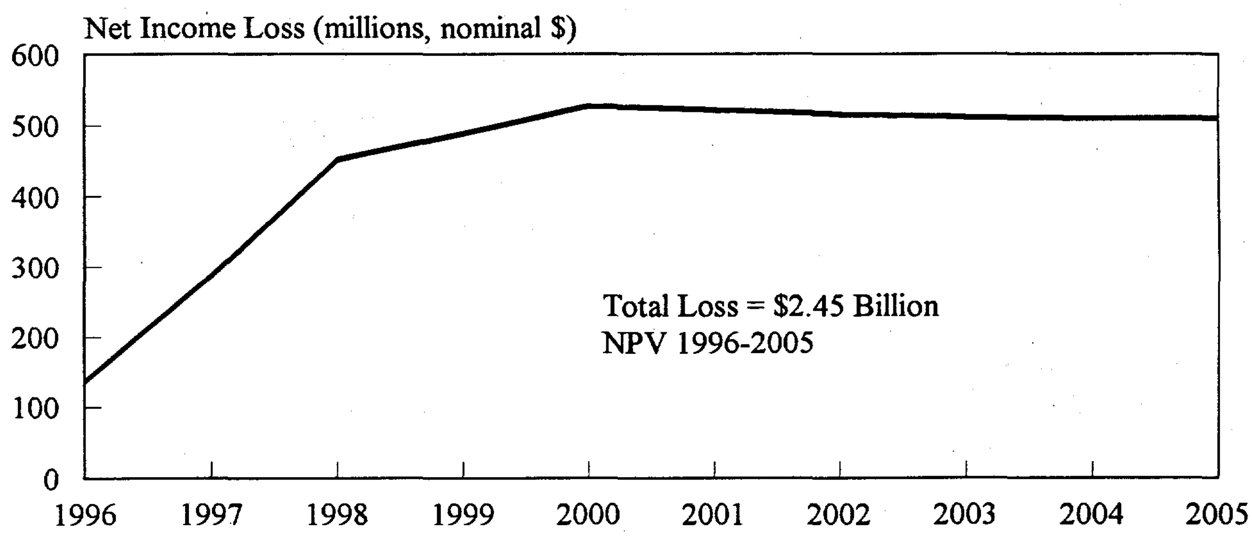

Figure 8. Transition costs (annual net income loss) for the base-case utility under the retail-wheeling scenario.

[8]We estimate transition costs using what we call the "bottom-up lose-sale" approach (Hirst, Hadley, and Baxter 1996a). Transition-cost estimates may differ, depending on utility and wholesale-market characteristics and the estimation approach used. For example, utility transition costs under the same retail-wheeling scenario are $2.32 billion using what we call the "bottom-up keep-sale" approach, or about $130 million less than the result from the "lose-sale" approach.

Table 4. Differences between the base-case and the retail-wheeling scenario

	1995	1996	1997	1998	1999	2000	2005
ANNUAL SUMMARY	(Retail wheeling results minus base case results)						
Retail sales (GWh) at busbar	0	-6,036	-13,611	-21,335	-23,012	-24,732	-26,024
Wholesale (spot) sales (GWh)	0	5,080	12,265	18,965	20,341	21,505	22,372
Wholesale (spot) purchases (GWh)	0	898	1,237	1,364	1,494	1,634	2,471
Net wholesale GWh	0	5,978	13,502	20,329	21,835	23,139	24,843
Retail wheeling	0	6,036	13,611	21,335	23,012	24,732	26,024
Peak demand at busbar (MW)							
Retail	0	-984	-2,258	-3,558	-3,873	-4,195	-4,418
Wholesale sales	0	578	1,249	1,701	1,821	1,907	2,094
Wholesale purchases	0	-468	-711	-742	-770	-801	-906
Retail wheeling	0	984	2,258	3,558	3,873	4,195	4,418
Costs and prices (1994 ¢/kWh)							
Average retail price	0	0.19	0.34	0.60	0.48	0.34	0.32
Average production costs							
Fixed	0	0.42	1.08	2.05	2.17	2.30	1.65
Variable	0	0.07	0.20	0.43	0.48	0.56	0.52
Total	0	0.49	1.27	2.48	2.66	2.86	2.17
Average marginal cost of generation	0	-0.55	-1.18	-1.71	-1.83	-1.92	-2.13
Wholesale price to meet demand	0	0	0	0	0	0	0
Return on equity (%)	0	-4.33	-9.22	-14.72	-16.20	-17.79	-17.37
INCOME STATEMENT (millions, nominal $)							
Revenues	0	-422	-921	-1,453	-1,591	-1,734	-1,870
Expenses							
Fuel	0	0	0	-9	-13	-19	-15
Power-purchase contracts	0	-4	-7	-8	-8	-8	-10
Spot purchases	0	-31	-45	-50	-56	-62	-102
Spot sales	0	-116	-299	-489	-540	-590	-704
Purchased power, total	0	-151	-350	-546	-604	-660	-815
O&M, fixed + variable	0	0	0	-1	-2	-2	-2
Production expenses, total	0	-151	-350	-557	-618	-681	-832
Nonproduction expenses	0	0	0	0	0	0	0
Book depreciation	0	0	0	0	0	0	0
Depreciation of regulatory asset	0	0	0	0	0	0	0
Revenue-sensitive taxes	0	-42	-92	-145	-159	-173	-187
Property taxes	0	0	0	0	0	0	0
Federal income taxes, current	0	-92	-191	-300	-325	-352	-340
Federal income taxes, deferred	0	0	0	0	0	0	0
Expenses, total	0	-284	-634	-1,003	-1,103	-1,206	-1,359
Interest expense	0	0	0	0	0	0	0
Net income	0	-137	-287	-451	-488	-527	-510
BALANCE SHEET (millions, nominal $)							
Assets	0	0	0	0	0	0	0
Equity	0	0	0	0	0	0	0

ESTIMATING PERFORMANCE BENCHMARKS

Several of the strategies we examine reduce utility operating costs (e.g., customer-service costs, A&G costs, transmission O&M, distribution O&M, and generation-plant O&M). To avoid making arbitrary assumptions about the potential for cost reductions, we establish performance benchmarks for each aspect of utility operations examined. Our objective is to estimate benchmarks that represent excellent cost performance for the electric-utility industry. We select cost performance at about the 90th percentile as our benchmark for each cost variable. That is, our definition of excellent performance is that only about 10% of the firms in the industry have equal or lower costs for a specific aspect of utility operations.

We establish each benchmark using essentially the same process for each area of operations. Beginning with a database that contains all U.S. electric utilities (RDI 1995), we select medium- to large-sized investor-owned utilities that predominantly serve retail customers. From this subset of utilities, we then plot and examine the resulting frequency distribution for each cost variable. We estimate the mean, median, standard deviation, and range for each distribution and check carefully for outliers (e.g., observations with a value several standard deviations removed from the distribution mean) or other data problems (e.g., missing values or negative values). In most instances, we delete such observations from the relevant initial distribution, and subsequently replot the distribution and reestimate the descriptive statistics. For several of the cost variables, we also consider whether certain obvious utility characteristics are associated with the distributions. We look at the relationship between utility size and customer-service costs, for example, to determine whether economies of scale might be operating. Our intent here is to adjust for these effects when necessary. Only at this juncture do we estimate the approximate 90th percentile value for each cost distribution.

To illustrate, we apply the above process to the category of A&G costs. From the population of U.S. electric utilities in 1994 (N = 3,206), we select utilities with summer peak demands greater than 499 MW (N = 200), with more than 100 retail customers (N = 148), and that are investor-owned (N = 115). We thus narrow our population of interest from the entire utility industry to this group of 115 firms. Figure 9 presents a frequency distribution for A&G costs ($/customer) for these 115 firms and certain descriptive statistics. These utilities spend an average of $156/customer on A&G costs, but costs range widely—utilities spend as little as $64 and as much as $422/customer.[9] Our inspection of the individual observations does not suggest any obvious outliers or data errors. In addition, we examine the correlation between A&G costs and utility sales (r = 0.14), number of residential customers (r = 0.05), number of total customers (r = 0.05), and customer mix (r = 0.00). None of these correlations suggest a significant association

[9]We also examined the distribution of A&G costs for each year from 1988 to 1994. The characteristics of this distribution are quite stable over this seven-year period. Selecting another year from this period or merging all seven years of observations into a single distribution, would have yielded quite similar results. We reached the same conclusion after examining the distribution of customer-service costs over the identical seven-year period.

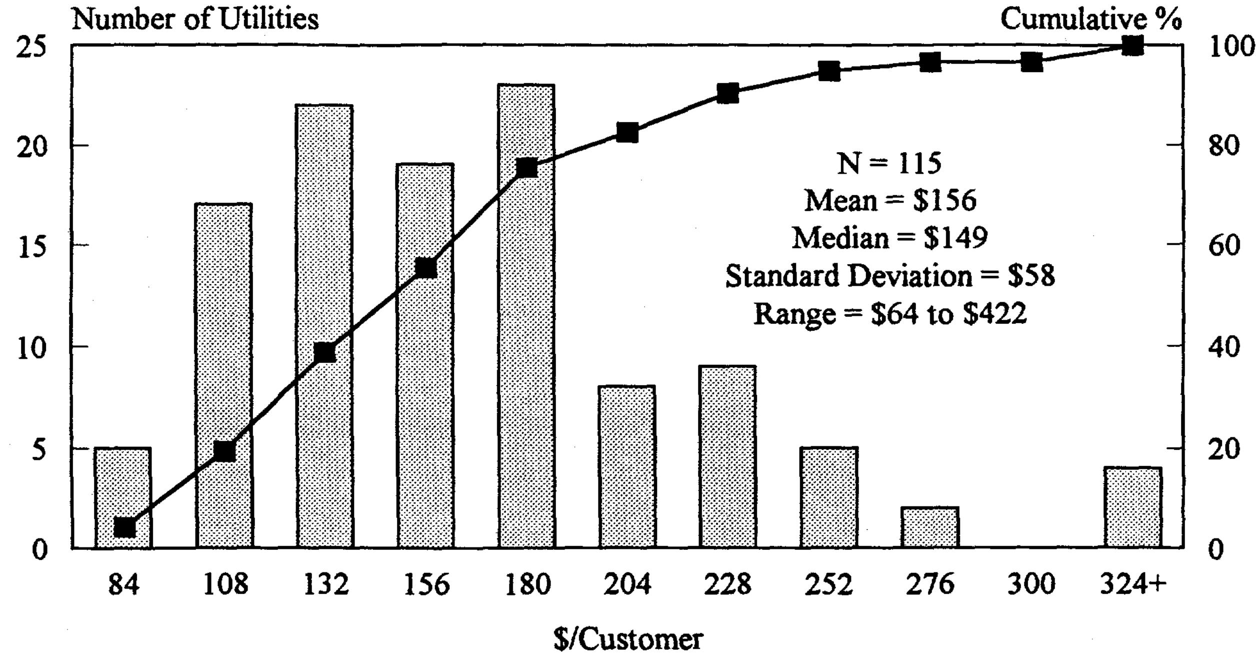

Figure 9. Frequency and cumulative distributions for A&G costs in 1994 (Source: RDI 1995).

between A&G costs and the respective utility characteristics.[10] As a result, we find no reason to adjust the frequency distribution shown in Figure 9.

Figure 9 also presents the cumulative frequency distribution for A&G costs. The cumulative frequency distribution allows us to readily identify the approximate 90th percentile, which for this variable is about $96/customer. We apply the same process to customer-service costs, transmission O&M costs, and distribution O&M costs. Of course, utility differences in A&G costs or customer-service costs may also partially reflect differences in how individual utilities define these two categories—what one utility defines as an A&G cost, another utility may treat as a customer-service cost. In addition, what one utility treats as an A&G or customer-service cost, another utility may assign to another cost category altogether. We account for the first classification difficulty by also estimating a performance benchmark for A&G and customer-service costs combined and then assessing the base-case utility's performance relative to this benchmark in Chapter 4. We do not address the second type of cost-classification problem.

[10]The available data did not allow us to examine all possible associations between utility costs and utility characteristics. We did not, for example, examine the relationship between T&D costs and the population or customer density of utility service areas.

The procedure differs slightly for generation-plant O&M costs. Here we assume that cost-performance benchmarks can only be appropriately established by comparing plants of similar type and vintage. Thus, for each type of utility-owned plant in our base-case utility, we select plants from our national database with the same fuel type, combustion process, capacity, and vintage. We include O&M cost data from 1990 to 1994 to help ameliorate the problem of an unusual year-specific O&M operation skewing the cost distribution. Thus, for the nuclear plant in our base case, we identify 48 comparable plants and use five years of O&M cost data for most of these plants. For the coal plant, we identify 36 comparable coal plants. From this point, we follow the same process used for the other cost variables to estimate the performance benchmark. The two natural-gas-fired plants in our base case have characteristics that provide a small comparison group (fewer than 30 observations). Instead of constructing plant O&M frequency distributions for these two plants, we estimate the average cost performance from 1990 to 1994 for the lowest-cost plant in the sample.[11]

Table 5 displays the base-case values and performance benchmarks for each of the cost variables we examined. In every instance, our cost assumptions for the base-case utility exceed the cost-performance benchmarks. The base-case utility's A&G, customer-service, transmission O&M, distribution O&M, and nuclear-plant O&M costs are also well above industry averages.

The relative importance of fixed and variable plant O&M costs depends on how much each plant runs. In general, however, we assign most O&M costs to fixed O&M. To illustrate, when the base-case utility's nuclear plant operates with a capacity factor of 80%, then the plant will incur annual fixed O&M costs of about $159 million and annual variable O&M costs of about $5 million. Comparable figures for the coal plant (70% capacity factor) are $36 million for fixed O&M and $15 million for variable O&M. The remaining thermal plants, however, have fixed-to-variable O&M cost ratios that are much closer to the nuclear plant's.

[11]RDI's database reports plant-specific O&M costs in total dollars and ¢/kWh. As a result, the base-case and performance-benchmark values are derived from total plant O&M costs. ORFIN requires that these aggregated costs be allocated to fixed and variable O&M. We used the Electric Power Research Institute's *Technical Assessment Guide* (1993) to estimate the fixed and variable components of total plant O&M costs. We used the resulting fixed and variable O&M cost shares to allocate total O&M costs to fixed and variable costs for the base-case utility and for the cost benchmarks for each plant.

Table 5. Performance benchmarks for utility cost variables

Cost Variable	Base-Case Value	Industry Average	Performance Benchmark
Administrative & general ($/customer)	231	156	96
Customer service ($/customer)	92	63	45
Administrative & general and customer service combined ($/customer)	323	219	154
Transmission O&M ($/kW-year)	8	4	2
Distribution O&M ($/kW-year)	20	12	8
Plant O&M			
Nuclear			
Fixed ($/kW-year)	125	91	61
Variable (¢/kWh)	0.06	0.04	0.03
Coal			
Fixed ($/kW-year)	23	26	12
Variable (¢/kWh)	0.16	0.18	0.08
Natural Gas 1			
Fixed ($/kW-year)	13	21	8
Variable (¢/kWh)	0.04	0.06	0.03
Natural Gas 2			
Fixed ($/kW-year)	22	24	8
Variable (¢/kWh)	0.09	0.10	0.03
Oil			
Fixed ($/kW-year)	6	7	2
Variable (¢/kWh)	0.11	0.13	0.03
Hydro			
Fixed ($/kW-year)	4	12	3
Variable (¢/kWh)	0.08	0.24	0.06

ASSESSMENT RESULTS

This chapter presents our assessment results for selected strategies. When necessary to understand the results, we also describe how we characterize a particular strategy in the assessment. We emphasize that the absolute values reported are less important than the direction and comparative magnitude of the assessment estimates. The absolute values themselves are linked to the assumptions that define the base case and the retail-wheeling scenario. A more useful application for the assessment results at this stage is to distinguish between strategies that may have large effects on transition costs and those with smaller effects.

MARKET ACTIONS

Results from our assessment of six strategies are displayed in Figure 10. Because this chapter contains several figures like Figure 10, we want to be clear about their contents. The *y*-axis displays changes in transition costs for utility shareholders as a result of introducing a strategy, identified along the *x*-axis, to the retail-wheeling scenario. Thus, Figure 10 presents results relative to the transition costs experienced by the base-case utility under the retail-wheeling scenario, as discussed in Chapter 3 (illustrated in Figure 3). A positive estimate means the strategy increased shareholders' transition costs relative to the retail-wheeling scenario; a negative estimate indicates the strategy decreased transition costs. A delay in wheeling, for example, results in transition costs to utility shareholders of $1.66 billion, which is $790 million (32%) less than the $2.45 billion in transition costs from the retail-wheeling scenario.

A strategy of rapidly opening retail electricity markets is represented by the retail-wheeling scenario we described in Chapter 3. The financial consequences for utility shareholders are severe, as evidenced by the retail-wheeling results presented in that chapter. If we assume a more extreme scenario, for example, one in which virtually all retail customers wheel by the year 2000, then the utility's transition costs increase 96% ($4.8 billion, or almost $2.4 billion more than the retail-wheeling scenario). The $4.8 billion estimate also approximates the transition costs electricity consumers bear, assuming that customers do not get access to competitive electricity markets and the utility fails to reduce costs. The $4.8 billion estimate defines the extreme effects of both rapidly opening retail electricity markets and keeping these markets closed for an extended period.

These extreme strategies bracket the range of possible outcomes from market actions, but a strategy to delay wheeling, for example, is unlikely to have as its objective an indefinite or lengthy delay. As a result, we also examine a strategy where retail wheeling occurs, but the start and pace differ from our retail-wheeling scenario. Compared to the retail-wheeling scenario, we delay the onset of wheeling for each customer group by two years and assume the time

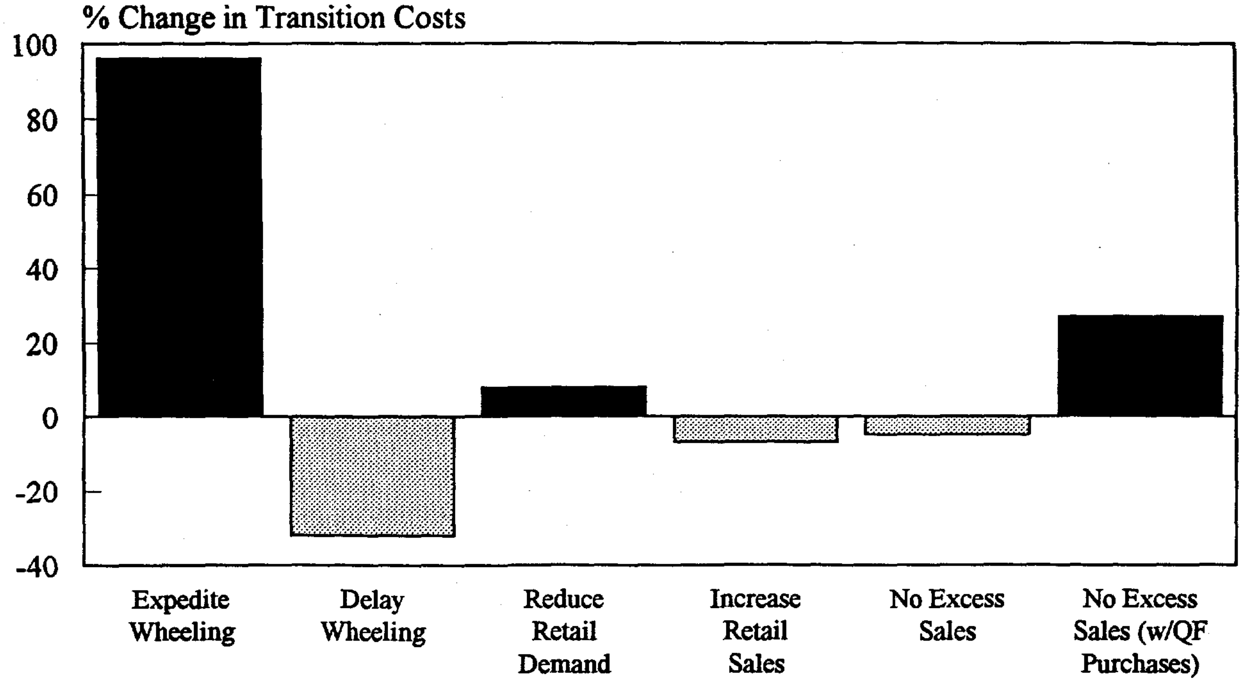

Figure 10. Effects of market actions on utility transition costs.

needed to reach the highest wheeling level is twice as long as in the retail-wheeling scenario.[12] We assume commercial and industrial customers begin to wheel in 1998 (instead of 1996) and 60% wheel by 2002 (instead of 1998). We assume residential customers begin to wheel in 1999 (instead of 1997) and 40% wheel by 2005 (instead of 2000). The strategy to delay wheeling reduces transition costs to shareholders by about 32% ($790 million), compared to the retail-wheeling scenario, for two reasons. First, the utility delays the financial consequences of retail wheeling by two years. Second, once wheeling begins, the utility has more time to depreciate sunk costs.

Analysts have identified improving system load factors as one possible objective of utility mergers. Other possible objectives are reducing costs, which we discuss later, and enhancing the value of each utility's asset portfolio. Setting aside the question of whether a utility will be able to effectively manage loads in a competitive environment, we assume the utility achieves a 5%

[12] In the delay-wheeling strategy, we estimate transition costs from 1996 to 2007, which reflects the absence of these costs in 1996 and 1997 and still provides a full ten-year period once the utility begins to incur these costs (1998 to 2007), as in the retail-wheeling scenario.

improvement in system load factor (i.e., from 66% to 69%).[13] The utility can increase its load factor either by reducing retail demand at peak periods or by increasing retail sales during off-peak periods. We would expect an increase in load factor through peak demand reductions to lower utility expenses, which it does. Unfortunately, utility revenues decrease more than expenses because improving the system load factor reduces revenues collected from customer demand charges. The net result is an increase in transition costs of 8% [$210 million (Figure 10)]. When a utility successfully increases its system load factor through reduced demand, this result suggests a need to revise the allocation between fixed and variable charges to avoid reduced earnings. The alternative strategy, increasing off-peak sales, increases utility expenses, but the resulting revenue increase exceeds the costs. The net result is a decrease in utility transition costs of 7% ($160 million).

The assessment framework incorporates the effects of marketing the energy freed by departing customers. Thus, the transition costs of $2.45 billion from the retail-wheeling scenario already reflect any benefits and costs derived from increased wholesale sales. To estimate these effects, therefore, we set the utility's annual wholesale sales in the retail-wheeling scenario to the same level as in the base case without retail wheeling (e.g., annual wholesale sales for the year 2000 return to about 7,700 GWh, as in Table 3). In this revised version of the retail-wheeling scenario, the utility is unable to convert any of the lost retail sales to wholesale sales. The result is a 5% reduction ($110 million) in utility transition costs. This counterintuitive result is explained by examining the change in wholesale-sales revenue and in production costs between the initial and revised retail-wheeling scenarios. In the revised retail-wheeling scenario, the utility experiences a decline in wholesale-sales revenue consistent with its lower wholesale sales. But over the ten-year analysis period, the decrease in production costs (fuel and variable O&M) from its own plants and from its most expensive long-term contracts more than offsets the revenue loss. ORFIN responds to the lower level of wholesale sales by reducing generation from utility-owned plants as well as by reducing purchases from the must-run QF contracts; this latter effect is particularly important. If the utility is able to reduce purchases from these must-run contracts, whose costs exceed 7¢/kWh, the production-cost savings are substantial. When do lower expenses more than offset lower revenues? For our base-case utility, only when the retail-wheeling levels become substantial.

We examine a second case where all the utility resources except the QF must-run contracts operate at the same level as above (i.e., the case where the utility has the same level of wholesale sales in the retail-wheeling scenario as in the base case). This second case examines the implications if the utility suffers a loss of retail sales but must purchase from the QF must-run facilities whenever they are available. In this case, transition costs increase by 27% ($660 million) because the utility purchases some above-market QF power and sells it at a loss on the wholesale market. Results from these two cases suggest that generalizing about the effects of marketing energy freed by departing retail customers is difficult; the benefits (or costs) of marketing excess energy will be utility-specific

[13]The more effective load-management strategies will use pricing mechanisms, such as real-time pricing or time-of-use rates, or use direct load control in conjunction with special pricing arrangements.

DEPRECIATION OPTIONS

In the base-case utility, three of six utility-owned generating plants are not fully depreciated by 1996. Of these three plants, only the nuclear plant carries a substantial depreciation expense ($115 million/year). We placed the nuclear plant in the rate base in 1988; the plant will be fully depreciated by 2018. The utility's revised depreciation strategy is to retire the plant's construction debt in the year 2000 by accelerating depreciation payments beginning in 1995. The result of this strategy is higher transition costs for shareholders from 1996 to 2000, but then lower transition costs beyond 2000. The net effect of accelerated depreciation is to increase transition costs by 5% (Figure 11) or $120 million.

Another strategy is to offset the increased costs of accelerated depreciation by decelerating depreciation of other assets. In the base case, the average depreciation expense for T&D is about $99 million/year (between 1996 and 2005), and the depreciation schedule is 50 years for new capital additions. To assess this strategy, we examine two cases. In the first case, we lengthen the depreciation schedule of T&D assets by 25 years (from 50 to 75 years), and in the second case, we lengthen the schedule by 50 years (from 50 to 100 years). Extending T&D depreciation by 25 years increases transition costs about 2% or $50 million (i.e., transition costs decrease about 3 percentage points or $70 million relative to the accelerated depreciation strategy). Extending depreciation of T&D assets by 50 years virtually offsets the increased cost from accelerating depreciation of the nuclear plant. Even this latter strategy leaves the utility with transition costs of almost $2.5 billion. But the assessment indicates the utility can alter depreciation schedules to

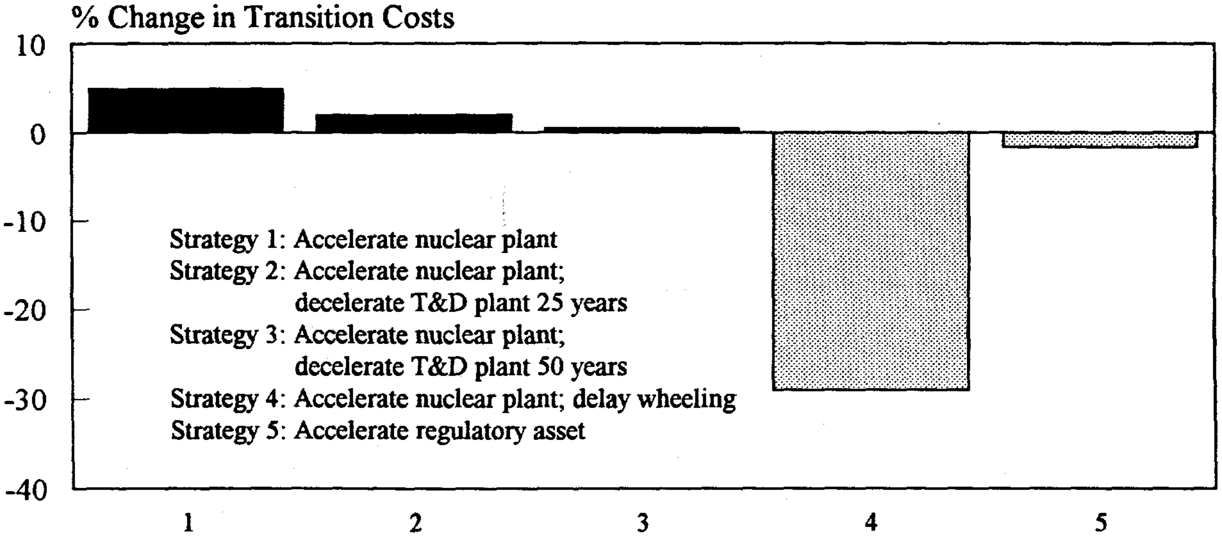

Figure 11. **Effects of depreciation options on utility transition costs.**

make itself no worse off than it was under the retail-wheeling scenario while retiring its largest generation-related debt expense. To make further headway on transition costs, however, the utility will have to combine depreciation options with other strategies.

To illustrate, we consider another combination of strategies (this one pairing up delayed wheeling with accelerated depreciation). These two strategies together reduce transition costs by 29% (about $720 million). With potential transition-cost reductions of this magnitude, utilities with substantial undepreciated generation assets will find this an attractive course of action.

Finally, the utility also has a regulatory-asset-account balance of $1 billion in 1995 that is fully depreciated by 2005. The utility's revised strategy is to accelerate the depreciation so that the regulatory asset is fully depreciated by the end of 1997. The net effect of this strategy is to decrease transition costs by almost 2% ($40 million). The higher transition costs from 1996 to 1997 are more than offset by the lower transition costs beyond 1997. Should the utility wait to accelerate depreciation until retail wheeling begins in 1996, its transition costs increase by 3% ($80 million).

RATE-MAKING ACTIONS

Unbundling rates is one probable outcome of industry restructuring. FERC's final rule (FERC 1996) on open access recognized the importance of unbundling ancillary services. FERC (1995) identified a set of ancillary services in its proposed rulemaking on open access, and others have subsequently described alternative sets of services (e.g., Hirst and Kirby 1996; North American Electric Reliability Council 1995). Efforts are also underway to unbundle the costs for these services (Wakefield et al. 1995). For unbundling, we examine a strategy in which the utility charges retail-wheeling customers for ancillary services.

Based on work at ORNL to assess ancillary service costs at 12 U.S. electric utilities, researchers found the average total cost to be about 0.4¢/kWh, of which about 0.3¢/kWh are fixed costs (Kirby and Hirst 1996). We implement this ancillary-services charge as an increase of $20/kW-year in the wheeling demand charge. Charging for ancillary services reduces utility transition costs by 10% ($240 million). Recent market tests should reveal how much electricity consumers are willing to pay for ancillary services (McCullough 1996).

Exit fees assign transition costs to departing customers. An exit fee is one transition-cost strategy FERC establishes for certain departing wholesale customers (FERC 1996). Exit fees could also be applied to departing retail customers.

As a first step, we estimate a one-time exit fee for the two customer classes in the base-case utility. Of course, an exit fee can also be structured as a stream of payments, presumably with carrying charges, but for simplicity we assume customers pay an exit fee the year they first take wheeling service. We use the following formula to calculate the one-time exit fee for each departing customer cohort by customer class:

$$\text{Exit Fee}_{c,r} = \left[\sum_{n=c}^{n=2018} \text{NPV (total generation cost}_n - \text{market price}_n + \text{regulatory asset cost}_n)\right] \times \text{average electricity use}_{r,\,1994}$$

The exit fee for year c and customer class r is the net present value, beginning in year c, of the difference between total generation costs, including regulatory asset costs, and the market price of generation. Total generation cost_n is the utility's fixed and variable generation costs in year n. Market price_n is the average wholesale market price in year n. Regulatory asset cost_n is the depreciation expense in year n for the regulatory asset account balance in 1994. Average electricity $\text{use}_{r,\,1994}$ is the average use in 1994 for customer class r.[14]

We note several important elements of this simple formula. First, we calculate an exit fee for customers departing in 1996, 1997, 1998, and so on; that is, for each cohort of customers leaving the utility. Second, while the time period for each cohort's calculation differs, the endpoint, the year 2018, is the same. We select 2018 as the common endpoint because that is the year the utility's last debt obligation (the nuclear plant) undertaken prior to restructuring is finally retired.[15] Finally, we use the average electricity use in 1994 for each customer class as a proxy for the expected future electricity use. Note that this assumption will lead to a slight underestimation of the utility's expected future revenue stream from these departing customers because one of our base-case assumptions is for a slight positive growth in electricity use per customer.

In addition, we use two approaches to estimating the difference between the utility's total generation costs and the market price. The first approach estimates this difference for a single year (e.g., the year the customer departs) and then holds this difference constant over time. The second approach, reflected in part by the above formula, accounts for how this difference might change over time. Our analysis assumes no change in fuel prices or market prices over time. These assumptions greatly ease our interpretation of the effects of different transition-cost strategies. We do forecast declines in fixed generation costs to reflect the depreciation of generation assets over time. As a result, total utility generation costs decline over time as generation assets are depreciated.

In Figures 12 and 13, we display results for these two approaches to exit-fee calculation for the base-case utility. Two observations are evident. First, exit fees calculated with the first approach (total generation costs held constant) are more than 50% higher than those calculated with the

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[14]In applications where real dollars are at stake, analysts should consider using each departing customer's recorded electricity use to estimate an exit fee rather than the customer-class average.

[15]Many exit-fee proposals argue that the end point for the calculation should be defined as the year that a utility's last financial obligation (be it a debt or long-term purchase) undertaken before restructuring is ultimately retired. We used a ten-year analysis period to estimate transition costs elsewhere in this report to be consistent with earlier ORNL work as well as with the work of other national studies, such as RDI's and Moody's. As a practical matter, extending our analysis beyond ten years would not substantially alter the relative results.

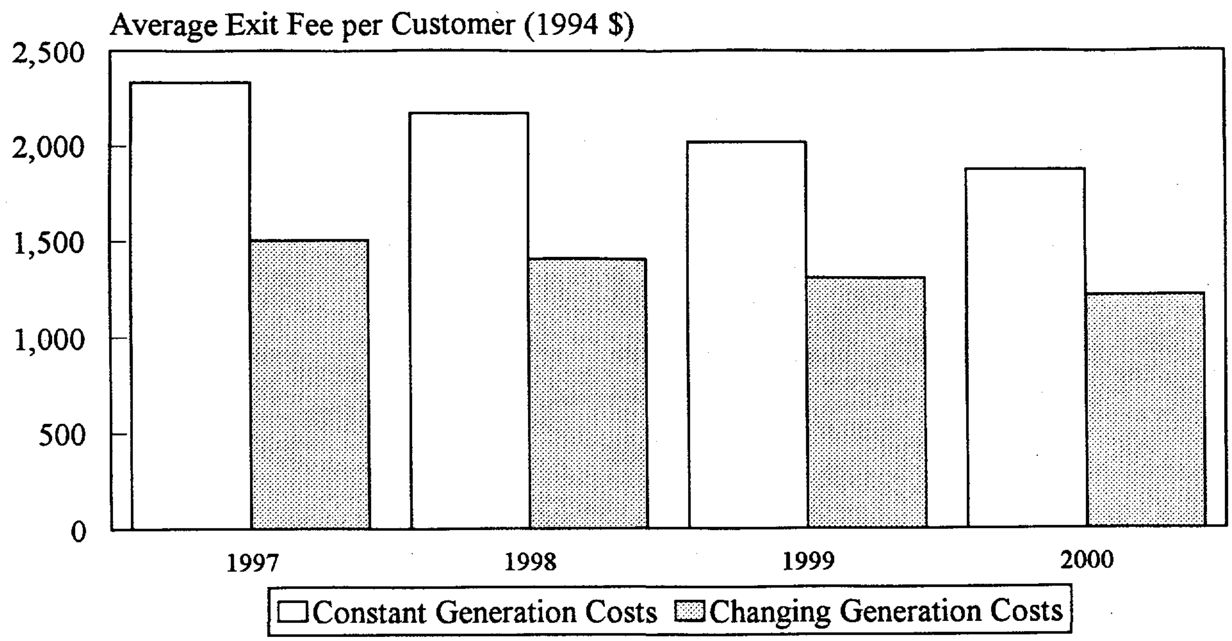

Figure 12. Two sets of exit fees for successive cohorts of departing residential customers.

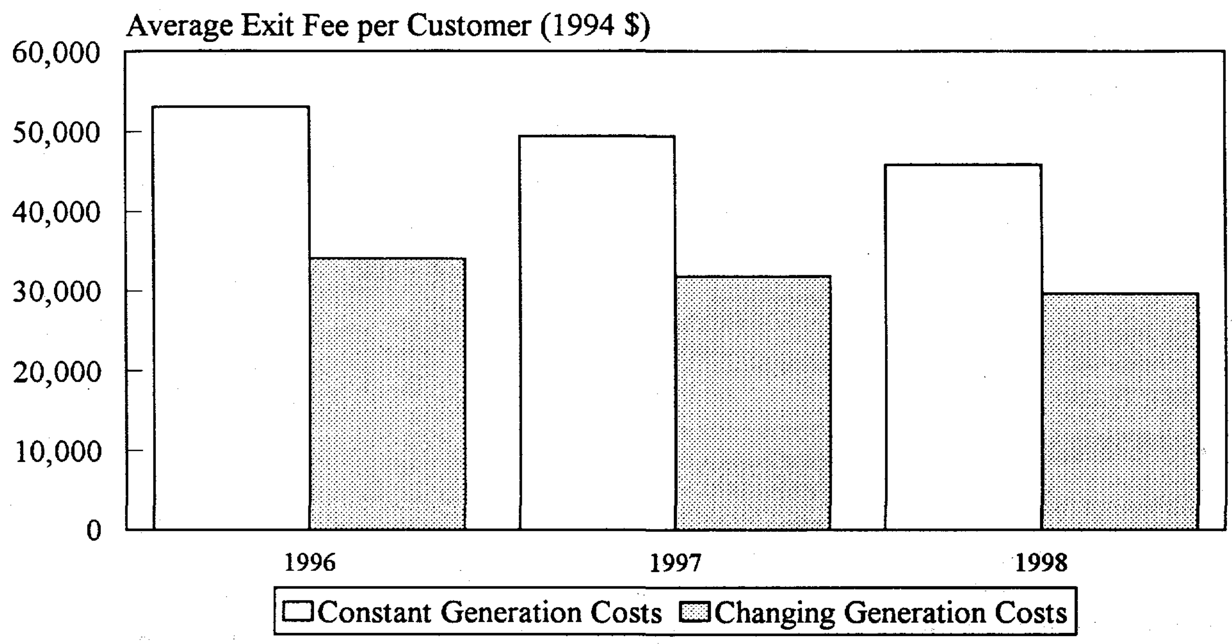

Figure 13. Two sets of exit fees for successive cohorts of departing commercial and industrial customers.

second approach (changing generation costs). Second, exit fees decline over time, and the first cohort departing pays the highest fee. Exit fees decline because each succeeding cohort has fewer years of transition costs rolled into the fee. More importantly, the difference between the utility's generation costs and the market price is greatest in 1996 and then declines each year because of depreciation. Customers that depart early must pay for this greater difference between utility costs and market prices.

Figure 14 shows the effects on the utility's transition costs of including these two sets of exit fees. The higher exit fees reduce the utility's transition costs by 146 %, which eliminates the utility's transition costs and results in a gain of $1.1 billion in net income from 1996 to 2005 (i.e., total impact is an increase of nearly $3.6 billion in net income compared to the retail-wheeling scenario). The lower exit fees eliminate 96% of the utility's transition costs (i.e., slightly under $2.4 billion). In principle, the lower exit fee should eliminate all utility transition costs; but as we noted above, our use of a proxy underestimates projected electricity use for departing customers.

We find that holding constant the first-year price difference between embedded generation costs and market prices will overestimate an exit fee intended to recover historical obligations the utility incurred on behalf of departing customers. While our assessment does not account for changes in fuel prices and market prices over time, it does account for a change that utility

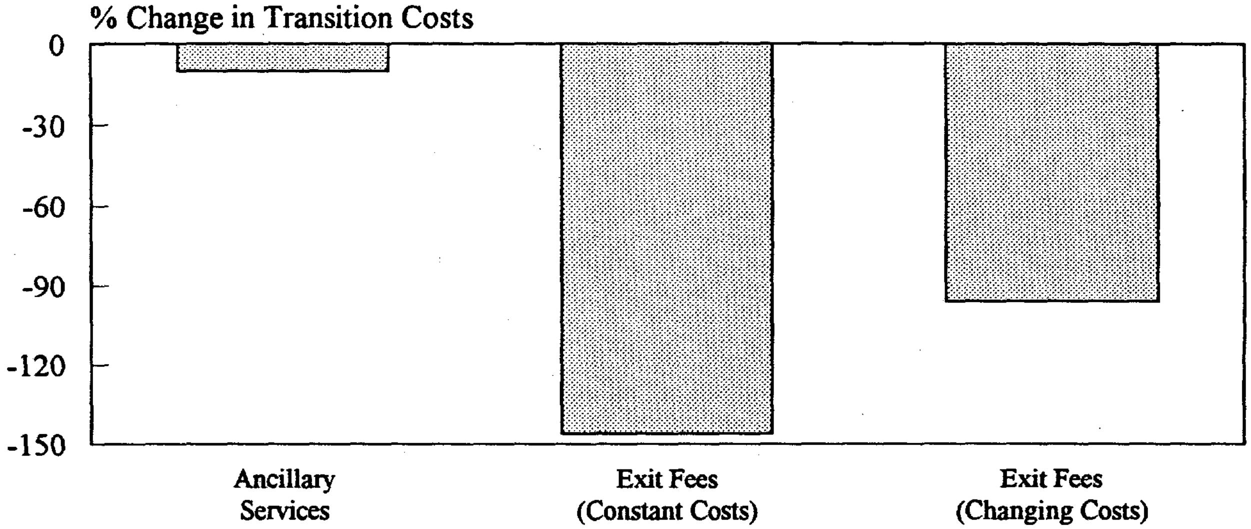

Figure 14. Effects of rate-making actions on utility transition costs.

planners and financial analysts can easily calculate—the reduction in utility fixed costs as assets depreciate over time.[16]

UTILITY COST REDUCTIONS

Nongeneration Costs

Differences in generation costs between regions has focused attention on the potential for efficiency increases and cost reductions in generation services. Analysts and commentators have paid less attention to the cost-reduction potential for nongeneration services. We do not posit the mechanism(s) that could be designed to achieve these reductions. The regulatory, research, and utility communities widely discuss performance-based regulation as one possible mechanism to encourage utilities to reduce costs over time. The transition-cost-recovery process itself could also provide utilities an incentive to reduce costs if a meaningful portion of these reductions are used to offset transition costs.

Figure 15 illustrates the potential effects on transition costs of reductions in six nongeneration costs. The first five cost variables compare base-case utility performance to a performance benchmark. Achieving benchmark performance in customer service reduces utility transition costs by 16% (almost $400 million). For A&G costs, the cost-reduction potential is 43% (more than $1 billion).[17] When we assess customer-service costs and A&G costs together, using the combined performance benchmark from Table 5, the cost-reduction potential is 54% ($1.3 billion), a somewhat smaller effect than when we consider these two categories separately and then simply add the results. Transmission O&M exhibits a cost-reduction potential of about 8% ($200 million), while achieving benchmark performance for distribution O&M reduces costs 10% ($250 million). These five cost variables suggest that the base-case utility has comparatively high costs in areas other than generation. Cost reductions in these five nongeneration areas have potentially large effects on utility transition costs and economic efficiency.

Public-policy-program costs are the sixth nongeneration cost variable in Figure 15. Our estimate of cost reductions here is not based on a performance benchmark. Instead, we assume that the utility reduces program expenditures by 75%, from $30 million/year to about $7 million/year. We also assume that these budget cuts are accompanied by reductions in services or benefits. As

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[16]Increasing market prices over time will have an analogous effect on transition costs. Thus, an analysis that holds market prices constant will overestimate transition costs should market prices actually increase over time. Of course, market prices are much more difficult to forecast accurately than the depreciation expense of power plants.

[17]We did not adjust costs to correct for regional differences in labor or materials costs. We note, for example, that the per capita personal income for the base-case utility's region is more than 10% above the national average (U.S. Bureau of the Census 1995). This difference suggests that labor costs for this part of the country are above average.

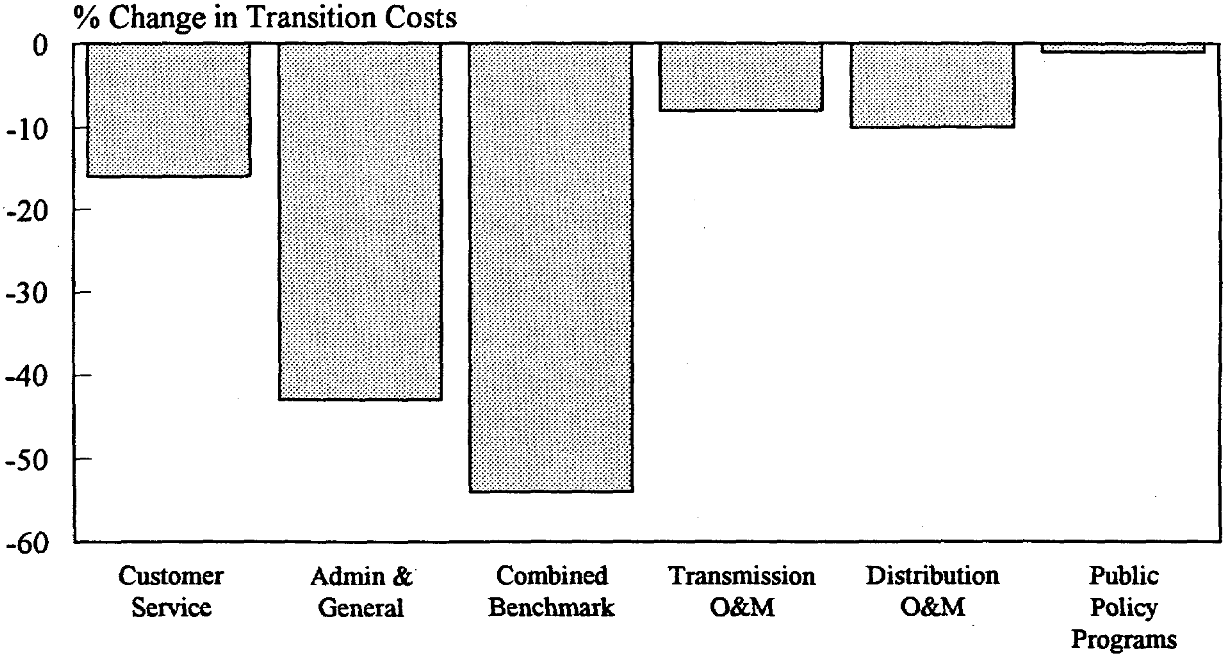

Figure 15. Effects of nongeneration cost reductions on utility transition costs.

a result, we redefine the base-case utility to reflect the 75% program reductions and we reestimate retail rates before introducing the retail-wheeling scenario. The ensuing reduction in transition costs is small because the base-case utility spends only about 1% of its revenues on public policy programs—a $23 million cut in public policy programs reduces utility transition costs by $23 million. Because cuts in public policy programs lead to equivalent reductions in the utility's transition costs, some members of the electricity policy community are concerned about the effects competitive pressures will have on public-policy-program expenditures in the absence of legislative or regulatory action.

Utility-Owned Generation

Figure 16 presents results of the utility's achieving performance benchmarks for generation-plant O&M costs; the white bars show the percent change in utility transition costs based on the absolute difference between the retail-wheeling scenario with and without the cost reduction, while the gray bars standardize the effects to generating capacity (e.g., if achieving benchmark O&M performance for a given plant reduces utility transition costs by 10% and if this plant's capacity is 500 MW, we express this reduction as 20%/1000 MW).

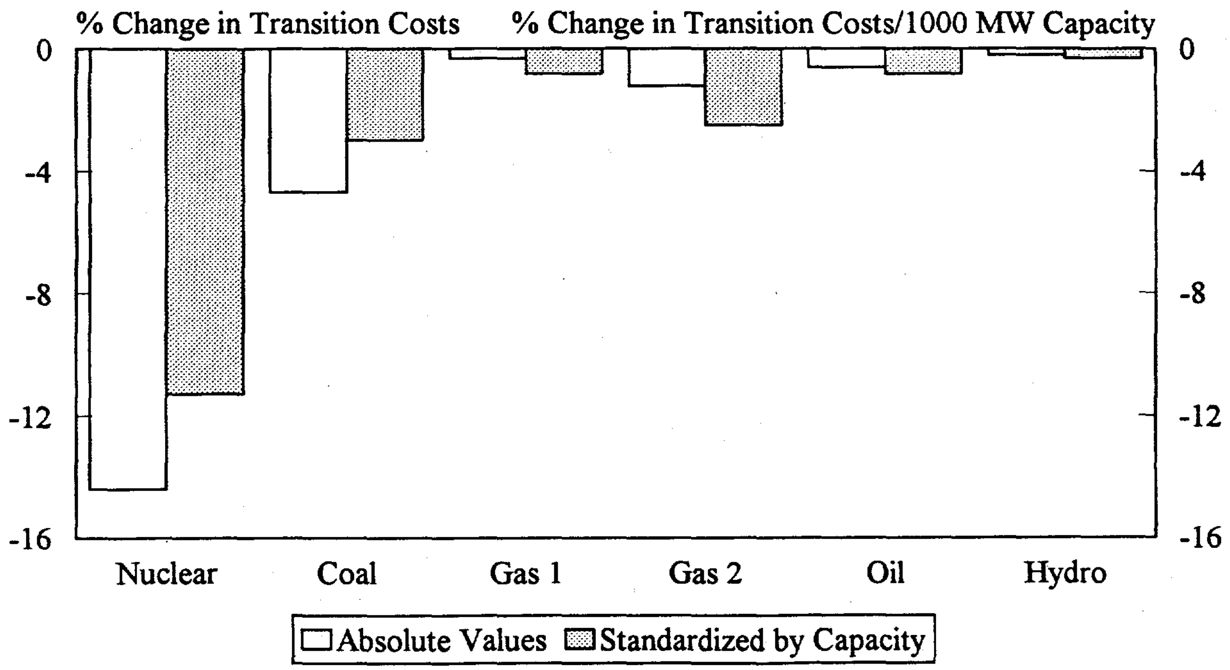

Figure 16. Effects of generation O&M cost reductions on utility transition costs.

Reducing O&M costs for the nuclear plant has by far the greatest potential to offset transition costs. Reaching the performance benchmark lowers transition costs by 14% (more than $300 million). The size of this potential cost reduction is expected because total O&M costs for this plant are about $163 million/year and achieving the performance benchmark cuts these costs in half.

The coal plant displays the next largest reduction at about 5% (more than $100 million). The nuclear and coal plants account for about 90% of the potential transition-cost offsets from improving plant O&M cost performance. The remaining plants have small absolute effects, although the second natural-gas plant's standardized effect approaches the coal plant's (Figure 16).

Of course, certain O&M cost reductions will themselves require investments by the utility, perhaps in training personnel, improving parts quality, or devising and implementing new procedures. The utility must decide which investments provide the highest return. In a competitive environment, for example, reducing the O&M costs on a plant whose marginal costs are well above market prices is not productive. Reducing variable O&M costs will not increase the operation of many plants because these costs are typically a small fraction of their total variable costs, which are the basis for economic dispatch. None of the variable O&M cost reductions we examine result in increased operation of the base-case utility's plants. In contrast, steps to reduce a plant's heat rate may enhance its competitive position. Another effective strategy is to reduce O&M costs for plants with marginal costs that already beat the market. For these plants, cost reductions increase the margin earned with each kWh generated; in our analyses, this is the case for both the nuclear and coal plants.

Figure 17 summarizes results from the cost-reduction assessments we have so far discussed. This figure suggests how cost reductions within the utility's system (i.e., from its own operations and plants) could offset transition costs. The generation O&M category here contains only the results for the nuclear and coal plants. Moving to the performance benchmarks yields potential savings of 91% (more than \$2.2 billion). Generation cost reductions are not the largest contributor to this total.

Power-Purchase Costs

The base-case utility spends more than \$1.2 billion/year on power purchases. Virtually all these power-purchase costs are incurred by the utility's 2,750 MW of "must-run" QF contracts. The utility's energy payments to the must-run QFs are about \$1 billion/year, with the balance being capacity payments. The total average cost of power purchased from QFs by the utility is 7.2¢/kWh. With market prices averaging 2.5¢/kWh, reducing power-purchase costs would clearly have a substantial effect on the utility's transition costs.

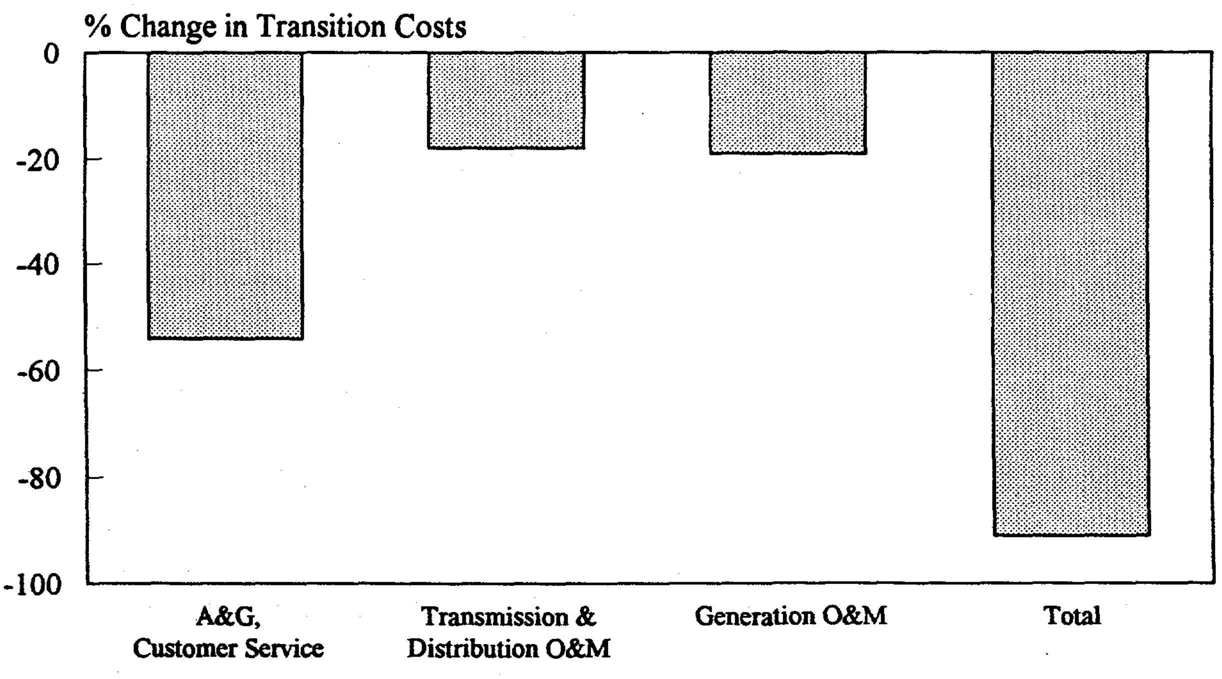

Figure 17. Effects of utility cost reductions on utility transition costs.

We examine four strategies to reduce the utility's power-purchase costs (Figure 18). The first strategy we assess is to discount the capacity payments of \$77/kW-year the utility makes to all QFs, not just the must-run facilities. This strategy discounts these payments to the market price for capacity. We construct a national average capacity price using the 10-year average market prices estimated by Moody's for each North American Electricity Reliability Council region (Fremont et al. 1995). Our estimated market price is \$40/kW-year. With capacity payments at \$40/kW-year, the utility reduces transition costs by 17% (more than \$400 million).

The second strategy also discounts current capacity payments to market, but the utility accelerates these payments.[18] By shortening the payment schedule, the utility must increase capacity payments to \$76/kW-year in 1995 and make these higher payments through the year 2000. The resulting cost increases through 2000 are more than offset by the subsequent cost reductions; the net result is a transition cost reduction of 13% (more than \$300 million).

In the third strategy, the utility continues to make the contracted capacity payments (at \$77/kW-year), but successfully negotiates full dispatchability provisions for all the must-run facilities. These facilities continue to set their energy price at 6¢/kWh. Not surprisingly, the utility rarely calls on these facilities, and the QF capacity factors approach zero by 1998 in this strategy (down from 70% in the retail-wheeling scenario). Compared to the retail-wheeling scenario, the utility's wholesale sales also decline (e.g., from 29,200 GWh to 13,800 GWh by the year 2000)[19] as do the revenues from these sales (from \$650 million to \$300 million). However, total power-purchase costs (contract costs minus the revenue from wholesale sales) also decline (from \$670 million to \$10 million). The result is a reduction in utility transition costs of 109% (almost \$2.7 billion; that is, transition costs are eliminated, and the utility's net income increases by about \$200 million compared to the base case).[20]

The fourth strategy maintains the must-run contract provisions but discounts the energy payments to the average market price of 2.5¢/kWh. The utility's wholesale sales return to the level projected in the retail-wheeling scenario (e.g., 29,200 GWh by the year 2000) as do

[18]QF contracts extend through the year 2010 in the base case.

[19]The examples in the parentheses in this and the following paragraph refer to projected costs and revenue in the year 2000.

[20]It does not follow from this result that all the utility's transition costs are tied to the must-run QF contracts. The result instead illustrates the importance of selecting carefully the reference point for estimating the impact of a strategy on utility transition costs (Figure 3). In estimating the impact of the third strategy, we assume the utility does not renegotiate dispatchability provisions until retail wheeling begins. We do not, therefore, reestimate the prices the utility continues to charge remaining retail customers for bundled services (i.e., the approach illustrated by the upper half of Figure 3). As a result, the utility's revenues from its remaining retail customers do not change relative to the base case, but the utility's total expenses decline relative to the base case. This explains why the benefit to the utility from this strategy exceeds the utility's total transition costs. If we instead assume that the utility should have renegotiated these contracts before retail wheeling began, we would have reestimated the utility's ensuing revenue requirement and retail rates. We ran such a case (i.e., using the approach illustrated by the lower half of Figure 3) and found the utility's transition costs decreased by 50% (\$1.2 billion).

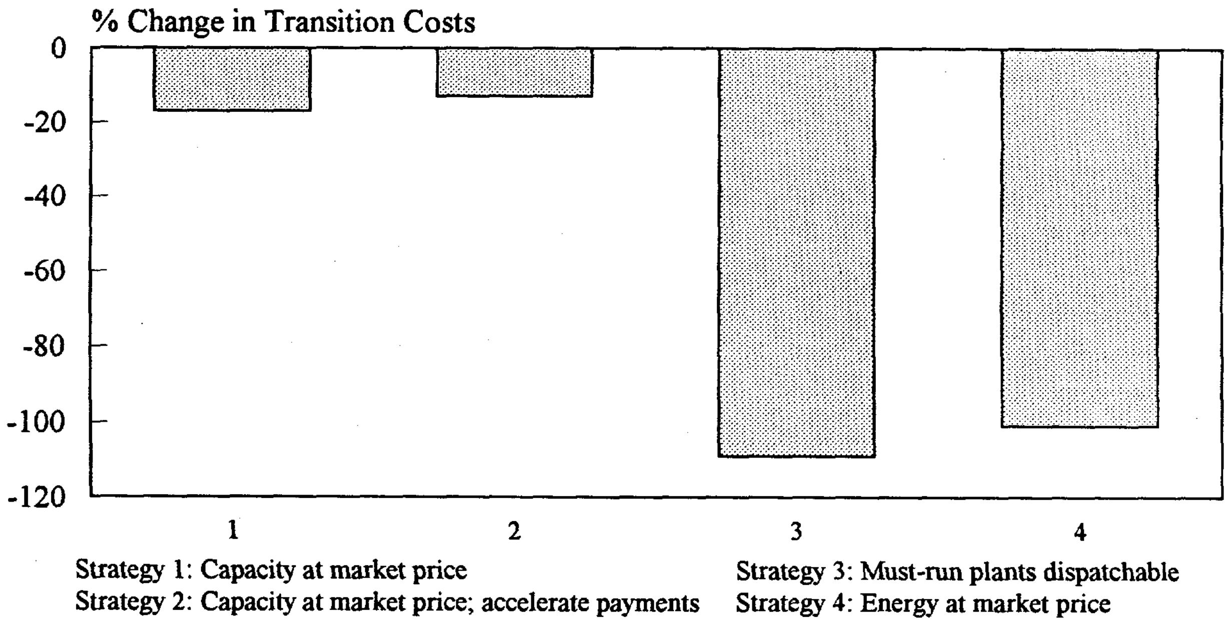

Figure 18. Effects of power-purchase cost reductions on utility transition costs.

revenues from these sales (e.g., $650 million), but power-purchase contract costs decrease substantially (e.g., from $1.3 billion in the retail-wheeling scenario to $730 million). As a result, total power-purchase costs decline dramatically (e.g., from $670 million in the retail-wheeling scenario to $80 million), and the utility's transition costs are eliminated.

From the above analysis, we see that every strategy that discounts energy payments to market, either by making must-run plants dispatchable or by continuing to dispatch plants but paying the market price for energy, produces large cost reductions. These reductions can exceed the utility's total transition costs. Of course, these reductions actually represent shifts in costs from utility shareholders to QF shareholders, which QF shareholders will resist. QFs will have incentives to renegotiate contracts when maintaining the full provisions of the existing contracts threatens the financial survival of the utility. In addition, provisions of certain existing QF contracts may become incentives to renegotiate once a competitive generation market is established. For example, consider a contract term that states that a QF must operate to receive its fixed energy payments. If the prevailing market prices are below the QF's operating costs, then the QF may have to operate the plant at a loss to receive its fixed payment. The QF will clearly seek to renegotiate its contract if this loss exceeds the value of the fixed payment. Similarly, a QF with energy payments tied to short-run avoided costs, as established by a competitive generation market, will be motivated to renegotiate if its operating costs exceed market prices. Finally, depending on their debt costs and discount rates, some QFs may prefer a contract buyout with up-front payments rather than continuing to receive payments over extended periods during a time of substantial changes in market structure and operation.

QF-shareholder resistance may be further reduced by sharing the gains achieved by utility shareholders. An example of such sharing is a renegotiated contract that eases the financial burden on the utility yet maintains a guaranteed long-term purchase obligation for the independent producer.

INTERPRETIVE CAUTIONS

Before summarizing our assessment results, it is instructive to review the interpretive cautions we raised in Chapter 3. From the utility's perspective, the retail-wheeling scenario is quite pessimistic. The scenario posits that other electricity suppliers have immediate access to the utility's retail customers and that many customers ultimately choose alternative suppliers. This scenario results in substantial earnings losses for utility shareholders. In contrast, the transition-cost strategies are optimistic. We assume the utility implements each strategy immediately and thus immediately experiences the benefits or costs. In addition, we do not include any costs to the utility in implementing these strategies; we are not conducting a cost-effectiveness or cost-benefit analysis. Further, we designed the analysis so that all the benefits (or costs) from each strategy flow to utility shareholders. Of course, we also designed the initial retail-wheeling scenario so that all transition costs are borne by these same shareholders. Finally, the utility must involve other actors to either implement or reap the longer-term benefits of these strategies. Even when pursuing internal cost reductions, for example, the utility must obtain approval from state regulators to be able to use these savings to offset transition costs over the long term. Reducing power-purchase costs will obviously involve utility negotiations with QFs.

SUMMARY

Table 6 groups the different strategies we assess by their potential effects on the base-case utility's transition costs. Because the absolute effects of different strategies are linked to the assumptions that define our base-case utility, this table provides a more general indication of how a strategy may affect other utilities. When reviewing Table 6, keep in mind that potentially affected utilities are not representative of all U.S. utilities. Potentially affected utilities will have substantial above-market costs in at least one of three areas: utility-owned generation, long-term purchase obligations, and regulatory assets.

Strategies with potentially large effects change transition costs to utility shareholders by 25% or more (i.e., more than $600 million). For at-risk utilities, delaying retail wheeling, charging exit fees to departing customers, and discounting QF energy payments to market are all likely to result in large reductions in utility transition costs. Rapidly opening retail markets will lead to large increases in transition costs for at-risk utilities.

The effects of the utility's marketing the energy freed by departing retail customers are difficult to assess. We include this strategy with others that had large effects because one of the cases we examine reveals a substantial increase in utility transition costs when the utility fails to pursue

Table 6. Potential effects of different strategies on base-case utility transition costs[a]

Potential effect on utility transition costs	Strategy
Large (25% or greater)	Rapidly open retail markets (+)
	Delay retail wheeling (−)
	Market excess energy (±)
	Charge exit fees (−)
	Reduce A&G costs (−)
	Discount QF energy payments to market (−)
Medium (between 5% and 25%)	Increase system load factors (±)
	Accelerate depreciation of the generation plant (+)
	Charge wheeling customers for ancillary services (−)
	Reduce customer-service costs (−)
	Reduce transmission O&M costs (−)
	Reduce distribution O&M costs (−)
	Reduce generation-plant O&M costs (−)
	Discount QF capacity payments to market (−)
Modest (less than 5%)	Accelerate depreciation of the generation plant and decelerate depreciation of the T&D plant (+)
	Accelerate depreciation of regulatory assets (±)
	Reduce public-policy-program costs (−)

[a]A "+" indicates the strategy increases transition costs; a "−" indicates the strategy decreases transition costs; a "±" indicates the strategy may increase or decrease transition costs.

sales in the wholesale market. A second case, however, shows a small decrease in utility transition costs. Our results suggest that the benefits (or costs) of marketing excess energy are related to the marginal generation costs of the utility's own plants, the operation and cost obligations of QF plants under contract to the utility, and the opportunities available in the wholesale market. These results are consistent with earlier findings on the importance of the interaction between the utility and the wholesale market in determining transition costs (Hirst, Hadley, and Baxter 1996a,b).

Reductions in nongeneration costs, such as A&G costs, may have substantial effects on transition costs. The comparative importance of reducing specific nongeneration costs depends on the cost structure of the utility in question. For our base-case utility, attaining benchmark performance in A&G costs reduces substantially its transition costs. For utilities with nongeneration costs close to or slightly below the industry average, the cost-reduction potential declines accordingly. In general, we expect the absolute cost-reduction potential to be greater in A&G than in customer service simply because industry-wide A&G costs are double customer-service costs (Figure 2). In addition, customer-service functions may become more important to utilities pursuing new or expanded market opportunities.

Strategies with medium effects change the utility's transition costs by 5% to 25% (i.e., $120 million to $600 million). Charging wheeling customers for ancillary services results in medium effects on transition costs. Most QF contracts incur lower costs for capacity than energy. As a result, discounting QF capacity payments to market will have less effect on a utility's transition costs than will discounting energy payments. Accelerating depreciation of the generation plant may have quite large effects on transition costs, depending on current depreciation expenses and the extent to which depreciation schedules are compressed. Because accelerated depreciation raises transition costs, utilities are unlikely to pursue this strategy in isolation.

System load factors can be increased by reducing on-peak demand or increasing off-peak sales. For the base-case utility, reducing on-peak demand lowers utility production costs, but reduces revenue from demand charges even more. The result is an increase in utility transition costs. Increasing off-peak sales increases production costs, but revenue from the higher sales more than offsets the cost increase. The absolute effect of increasing system load factors on transition costs depends on how much load factors change. For most utilities, we expect these changes to be small in the short term. As a result, the attendant effects on utility transition costs are unlikely to be much greater than the ones illustrated here, and may indeed be more modest.

Our analysis illustrates that utilities can offset the increased costs of accelerated depreciation by decelerating the depreciation of other assets. Any transition costs remaining to the utility will be modest. Accelerated depreciation can also be applied to regulatory assets. Our results suggest that whether accelerating depreciation of these assets increases or reduces utility transition costs depends partly on when the change in depreciation begins.[21] If begun before retail wheeling starts, utility transition costs will decrease. If begun after wheeling starts, utility transition costs will probably increase. If the at-risk utility has substantial above-market generation costs or power-purchase contracts, the effects of regulatory asset depreciation will be modest. Accelerating the depreciation of regulatory assets will have a more pronounced effect as these assets make up a growing share of any given utility's total transition costs.

Finally, reducing public-policy-program costs will have modest effects on transition costs for most utilities. The ultimate effect, of course, will be determined by the size of the initial programs and the extent of cuts; yet even a utility spending 5% or more of its annual revenues on these programs can hardly expect to achieve large reductions in transition costs. Instead, utilities will be motivated to reduce these expenditures to cut costs and prices.

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[21]This observation also holds for accelerated depreciation of generation assets. For example, the utility's transition costs will decrease if regulators permit a utility to recover the capitol cost of its generation plants before retail wheeling begins.

CONCLUSIONS AND RECOMMENDATIONS

STRATEGIES TO ADDRESS TRANSITION COSTS

We identify a wide range of strategies to address transition costs. These strategies rely on market actions, depreciation options, rate-making actions, cost-reduction options, tax measures, or other approaches. Many of the proposed strategies essentially shift costs from one set of economic actors to another. Of the 34 individual strategies we identify, retail ratepayers have primary or secondary responsibility for paying transition costs in 19, shareholders in 12, wheeling customers in 11, taxpayers in 8, and nonutility power suppliers in 4.

Cost shifting is not necessarily a negative outcome, particularly when decision makers are selecting and implementing strategies based on clearly established and equitable criteria. Such criteria can be established through negotiations with stakeholders and by actively seeking public comment on proposed strategies. Certain strategies can actually mitigate transition costs by using reductions in future utility costs to offset transition costs resulting from past obligations.

ASSESSMENT OF SELECTED STRATEGIES

Using an integrated utility planning model, we examine reasonably complete representations of ten strategies and partial representations of two others. Several of the strategies we study have large effects on the base-case utility's transition costs. Actions to either rapidly open retail markets or delay retail wheeling have dramatic effects on utility transition costs. Assessed with reference to the base-case utility, for example, rapidly opening retail markets increases utility transition costs by more than $2 billion while delaying wheeling decreases costs by almost $800 million.

Charging exit fees to departing customers eliminates the utility's transition costs. Regulators must use care, however, when developing or reviewing exit-fee proposals. Exit-fee calculations are made just like certain administrative approaches to estimating transition costs and, as a result, suffer the same weaknesses. Exit fees require a forecast of the revenue the utility would expect to receive if the departing customer continued to purchase generation services from the utility. Exit fees also require a forecast of future market prices for generation services. The sensitivity of the exit-fee calculation to the market-price forecast suggests that regulators may want to establish provisions for exit-fee reconciliation should the price forecast deviate substantially from observed values. Another part of the exit-fee calculation also has an important effect, but this effect can be much more reliably predicted. Over time, the utility's sunk costs will decline. The associated change in the utility's fixed costs is readily calculated and should be included in exit-fee estimates. Ignoring the decline in utility fixed costs over time can result in exaggerated exit fees.

Most of the utility cost-reduction options we examine lead to substantial decreases in costs. For the base-case utility, reducing A&G costs produces the largest potential offset in transition costs. The cost-reduction potential for customer services and O&M is also sizable. These cost-reduction options stand apart from the other options we examine. Utility cost reductions may be used to offset, rather than simply shift transition costs. Thus, successful utility cost-reducing efforts lead to economic-efficiency gains.

The effects of marketing excess energy on utility transition costs are difficult to predict. In one case we examine, for example, the utility's failure to market excess energy actually decreases its transition costs. Thus, success of a marketing strategy will depend on the operating costs of the utility's plants, its long-term power-purchase obligations, and the characteristics of the wholesale market. In any case, utilities with substantial transmission capacity will find marketing to be a more effective strategy than utilities without sufficient interconnections. Reducing public-policy-program costs has only a modest effect on utility transition costs.

Our base-case utility has an abundance of above-market power-purchase contracts without dispatchability provisions. Actions the utility can take to reduce these costs, particularly the energy payments, through renegotiating or buying out these contracts will have dramatic effects on transition costs. The sustainability of long-term nondispatchable power-purchase contracts with fixed payments well above current or anticipated market prices is a major issue for the electricity industry.

Accelerating the depreciation of generation assets increases costs and shifts costs from future ratepayers to current ratepayers. Some utilities may be able to offset these cost increases by decelerating the depreciation of transmission or distribution assets or by combining accelerated depreciation with other strategies that reduce costs.

Our analysis also suggests the need for more systematic assessments of specific strategies. Results from this study should be interpreted with some caution. The potential of specific cost-reduction options, for example, will depend on the cost structure of actual utilities. We recommend studies that assess strategies for utilities with cost structures that differ from the base-case utility examined here. For example, utilities with more expensive plants, with lower-cost QF contracts, or with nongeneration costs closer to industry averages may benefit from a somewhat different mix of strategies than the ones identified in this study. We have not determined whether the cost-performance benchmarks used in our study could be widely achieved. While utilities differ greatly in cost performance, we have not controlled for all the variables that could contribute to variations in costs, such as regional differences in wage rates. Nevertheless, the potential cost reductions are sufficiently large to warrant considerably closer examination in future studies.

RECOMMENDATIONS

Most of the strategies we examine require the cooperation of other parties, including regulators, to be implemented successfully over the long term. An important exception is the strategy to market the energy freed by departing customers. As a result, financial stakeholders must engage in negotiations that hold the promise of shared benefits.

Left to their own devices, most financial stakeholders will pursue their self-interests. Utilities with transition-cost exposure will argue for full shareholder recovery. Ratepayers will argue for lower rates, choice of suppliers, and abandonment of the financial obligations that utilities incurred on their behalf. QFs will demand that contracts be fulfilled to the letter, although many regions have excess capacity. We characterize these positions as "winner-take-all." Testimony on transition cost issues filed at FERC and at proceedings in many states are replete with examples of these "winner-take-all" arguments. In addition, agents in exclusive pursuit of self-interest may also pursue multiple public forums to press their cases. Dissatisfied with a regulatory decision on transition costs, parties may seek redress through state legislatures, Congress, or the courts.

What is needed to break this logjam? The promise that no one party will bear all costs, that costs will be allocated across financial stakeholders, that competitive generation markets will be established, and that transmission and distribution services will be restructured in a timely and orderly way that affords opportunities for gains by all financial stakeholders. Absent this promise to achieve a negotiated consensus on the dual issues of transition costs and industry structure, restructuring efforts may bog down further in extensive regulatory and judicial disputes.

Consider the issue of bringing long-term power-purchase contracts closer to market. In certain circumstances, independent power producers will be motivated to negotiate with a utility whose long-term survival is jeopardized by continued payments for above-market-priced power. Because the benefits of a renegotiation to the utility may be quite large, the independent producers may be further motivated if the utility is able to share benefits. An example of sharing is a renegotiated contract that eases the financial burden on the utility yet maintains a guaranteed long-term purchase obligation for the independent producer. Sharing could also take place up front as a contract buyout.

Reducing utility costs is another area requiring cooperation between stakeholders as well as regulators. The competitive market will provide ample incentives for the utility to reduce generation costs. The utility's motivation to reduce costs in other areas, however, will depend on the incentives established. A utility exposed to transition costs will have less motivation to reduce nongeneration costs if regulators and consumer groups demand that all these savings flow to ratepayers. In contrast, a utility able to use a portion of its cost reductions to offset its transition-cost exposure will be more motivated to pursue cost efficiencies. To be successful, this strategy requires regulators and consumers to be satisfied with a price reduction that reflects only a portion of the costs saved by the utility. Only by rejecting "winner-take-all" strategies in favor of strategies that benefit multiple stakeholders will the transition-cost issue be expeditiously resolved.

The financial stakes involved in resolving the transition-cost debate are high. Appropriate decision makers (e.g., legislators or regulators or both) have a potentially key role to play in convening and brokering negotiated settlements that avoid "winner-take-all" outcomes. The tough decisions on transition costs are still to be made. Leadership is needed to obtain the economic-efficiency gains that advocates of industry restructuring have promised, while recognizing that the transition to a new industry structure has costs and acting to allocate those costs equitably.

ACKNOWLEDGEMENTS

We thank Suraj Kanhouwa, Diane Pirkey, and Val Jensen for their support and encouragement in this project. We thank Brendan Kirby for providing the data used to establish industry performance benchmarks. This report benefited greatly from reviews of an earlier draft by Wes Arlukiewicz, Eric Blank, Paul Carrier, Paul Fremont, Larry Hill, Suraj Kanhouwa, Steven Keller, Lance McKinzie, Betsy O'Brien, Diane Pirkey, Chris Seiple, and Richard Viinidainen. Finally, we thank Fred O'Hara for his editorial support and Glenda Hamlin for overseeing the report's printing and distribution.

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