Who Should Pay Transition Costs?

Once they decide how much of its transition costs a utility should be allowed to recover, regulators need to implement workable cost-recovery mechanisms. Such mechanisms should encourage competition in the generation sector and should neither unduly favor nor hamper the interests of utilities, independent power producers or customers.

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The most contentious arguments ... involve how we deal with the transition costs associated with moving to competition. ... [T]here is no consensus on how the Commission should address the stranded cost issue. In fact, petitioners are at polar extremes as to what the Commission should do regarding stranded costs.[1]

—Federal Energy Reg. Comm'n

Transition costs are enormously contentious for two reasons. First, a great deal of money—roughly $150 billion—is potentially at stake. Second, the decisions on how these costs should be allocated—among electric-utility shareholders, retail and wholesale customers, independent power producers and other wholesale electricity providers, and state and federal taxpayers—depend much more on policy judgments than on analysis.

This article, based on a comprehensive analysis of transition-cost issues,[2] summarizes the primary arguments in this debate, and reviews recent regulatory and legislative decisions determining which parties are responsible for transition costs. Because some level of cost recovery is likely to be allowed in most jurisdictions, we also discuss the design of cost-recovery mechanisms aimed at promoting competitive electricity markets.

I. Pro-recovery Arguments

The primary proponents of the argument that utilities are entitled to and should receive full recovery of their transition costs are, not surprisingly, the investor-owned utilities themselves. Baumol, Joskow and Kahn offer arguments, based on economics and regulatory policy, supporting shareholder recovery of transition costs (TCs).[3] They suggest that increasing economic efficiency should be the primary objective of restructuring the electricity industry. They argue that, when properly structured, competitive markets are more likely to increase economic efficiency than are regulated markets. These efficiency gains will involve both productive efficiency (i.e., providing goods at minimum cost) and allocative efficiency (setting prices correctly, based on marginal costs).

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

Baumol, Joskow and Kahn also indicate that TC recovery can be compatible with efficient competition when the recovery mechanism is properly structured.[4] To ensure that competition between rival suppliers is based on efficiency, they recommend that the costs of historical obligations be assessed on all customers who have benefited from these obligations.

Baumol, Joskow and Kahn offer arguments, based on economics and regulatory policy, supporting shareholder recovery of transition costs.

Rowe and Graening develop legal arguments to justify full payment to utility shareholders of TCs.[5] On the basis of the Takings Clause of the Fifth Amendment, they argue that the government may require private property owners to cede rights to that property to serve the public good, but it must then ensure just compensation to the owner. Paying transmission owners the embedded costs of their transmission system is irrelevant, in part because transmission is an integral part of a utility's larger generation, transmission, and distribution system. Allowing others to use a utility's transmission system adversely affects the value of a utility's generation assets, and for this reduction in value the utility is entitled to full compensation. Rowe and Graening write:

> The integration of distribution, transmission and generation into a tightly woven commodity delivery system performs as a whole. One part severed from the others can drastically reduce the property's comprehensive value. If the wires are severed from the generation, their loss will destabilize the value of the overall property. The result would be akin to a tricycle with only two wheels—broken and going nowhere.[6]

Kolbe and Tye argue that the rates of return historically allowed by state public utility commissions were insufficient to compensate shareholders for the risk associated with retail competition.[7] For utility shareholders to have been automatically compensated for the risk of TCs, the allowed rate of return would have had to be much higher than the actual cost of capital. Further, they say, the increment above the cost of capital is very case specific (i.e., it depends on the particular situation facing that utility). Kolbe and Tye believe it is unlikely that PUCs were performing the necessary company-specific calculations to determine the authorized return on equity.

II. Anti-recovery Arguments

Large industrial customers and low-cost utilities, among others, oppose payment of full TCs to utilities.[8] They argue that such payments will have anticompetitive and uneconomical consequences by providing payments to high-cost producers that will discriminate against low-cost producers. Full-cost recovery also ignores any utility responsibility for these costs and their consequent obligation to pay for at least some of them. Navarro believes that allowing full recovery of TCs is unfair to consumers, would provide a shield for high-cost producers and discriminate against low-cost producers, and would reward utilities for past "bad management decisions."[9]

Rose argues that TC recovery by utility shareholders is not supported on grounds of either economic efficiency or historical regulatory policy.[10] He states that the concept of transition costs and arguments for its recovery by utility shareholders have little basis in economic theory, legal precedence, or precedence in other deregulated industries.

Rose first considers the argument that TC recovery is required for economic efficiency. This argument is based on a narrow definition of efficiency—preventing uneconomical bypass of the utility's system (i.e., selecting another supplier when the utility is the lowest-cost provider for that customer). He argues instead for a broader perspective on efficiency, one that considers the long-term promotion of competitive markets and incentives for suppliers to minimize costs over time. In his view, longer-term gains from price reductions to consumers are likely to exceed the shorter-term losses from uneconomical bypass. Allowing TC recovery may impair the development of competitive markets by reducing utility incentives to lower costs, acting as a barrier to entry and exit of other suppliers in the marketplace, and creating an asymmetry between utility risk and reward. Finally, even if competitive forces lead to utility bankruptcies, society's resources will be more efficiently allocated after the financial readjustments bankruptcies will bring.

Opponents argue that stranded cost recovery will have anticompetitive and uneconomical consequences.

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

In contrast to Kolbe and Tye, Bradford believes that utility shareholders historically have been compensated at levels high enough to cover the risks of some loss on strandable investments.[11] Indeed, between 1977 and 1991, the annual total return to shareholders for 81 utilities averaged 13.3 percent per year, higher than the 13.2 percent for unregulated industrial firms even though electric-utility stocks were less risky than the market as a whole.[12]

III. Government Decisions

At the federal level, the Council of Economic Advisers has favored utility recovery of transition costs:

> In unregulated markets the possibility of stranded costs typically does not raise an issue for public policy—it is simply one of the risks of doing business. However, there is an important difference between regulated and unregulated markets. Unregulated firms bear the risk of stranded costs but are entitled to high profits if things go unexpectedly well. In contrast, utilities have been limited to regulated rates, intended to yield no more than a fair return on their investments. If competition were unexpectedly allowed, utilities would be exposed to low returns without having had the chance to reap

the full expected returns in good times, thus denying them the return promised to induce the initial investment. A strong case therefore can be made for allowing utilities to recover stranded costs where these costs arise from after-the-fact mistakes or changes in regulatory philosophy toward competition, as long as the investments were initially authorized by regulators. … The case for allowing recovery is even stronger where stranded costs arise from regulatory obligations imposed on utilities [such as QFs]. … To be sure, utilities should be granted recovery only of costs prudently incurred pursuant to legal and regulatory obligations to serve the public.[13]

FERC, in its Orders 888 and 888-A,[14] clearly favors utility recovery of "legitimate, prudent, and verifiable [wholesale] costs." FERC provides an extensive discussion of the many comments it received on this issue, both for and against cost recovery, and the basis for its decision to allow utilities the opportunity to recover all their TCs. Similarly, the California Public Utilities Commission[15] and the California legislature[16] decided to allow utilities the opportunity to recover their retail transition costs.

In granting the opportunity for full stranded-cost recovery, FERC also set out some significant limitations on recovery. It limits utility cost recovery to only those costs that can be directly attributable to Order 888, which mandated open-access transmission at the wholesale level. If, for example, a wholesale customer physically leaves a utility's service area, the utility's losses associated with this departure would not qualify for cost recovery under FERC's rule. In addition, FERC limited recovery to costs incurred prior to July 11, 1994, the date of its original stranded-cost notice of proposed rulemaking. Finally, FERC requires a utility to demonstrate that it had a "reasonable expectation" that it would continue to serve the departing wholesale customer for a certain amount of time. Thus, although FERC decided to allow utilities the opportunity to recover 100 percent of the costs stranded by increased transmission access, it limited these opportunities to those that are a direct consequence of FERC's actions. Also, FERC's rule applies only to entities for which financial obligations are defined by contracts.

In granting the opportunity for full cost recovery, FERC also set out some significant limitations on recovery.

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

The California legislature also sought to ensure that residential and small commercial customers would benefit from restructuring that state's electricity industry. To that end, the legislature authorized the issuance of up to $10 billion of government bonds, the proceeds of which would be used to guarantee residential customers a minimum ten percent rate reduction and help pay for TCs. The lower interest rate on government vs. utility bonds, the longer amortization period (ten vs. five years), and the exemption from state income taxes will be used to provide the rate reduction to residential customers. (But these securitization benefits have a cost: The state *guarantees* that retail electricity consumers will pay the interest and principal associated with these bonds.) The legislature decided that all retail customers will pay for transition costs through a nonbypassable competition transition charge, allocated across rate classes in a manner similar to the cost allocation in place as of June 1996. The California legislation is significant because it provides strong assurances of recovering a substantial portion of their transition costs. Also, by "securitizing" some of these costs, it reduces their magnitude.

Perhaps taking a cue from California, the Pennsylvania General Assembly has authorized the Pennsylvania Public Utility Commission to issue qualified rate orders to utilities for the issuance of transition bonds.[17] As in California, these bonds would require a lower interest rate because of the state's backing:

> Notwithstanding any other provision of law, the Commission has the power to specify that all or a portion of a qualified rate order shall be irrevocable. To the extent specified, neither the order nor the intangible transition charges authorized to be imposed and collected under the order shall be subject to reduction, postponement, impairment of termination by any subsequent action of the Commission. ... The Commonwealth will not limit, or alter or in any way impair or reduce the value of intangible transition property or intangible transition charges approved by a qualified rate order until the transition bonds and interest on the transition bonds are fully paid and discharged or the contracts are fully performed on the part of the electric utility.

Commissioner John Hanger, a member of the Pennsylvania Commission, suggests applying "different recovery levels for different types of stranded investments."[18] Commissions can consider the degree of utility-management responsibility for the TCs that exist in each category. In addition, the TCs associated with utility-owned generation assets includes both a return *of* investment and a return *on* investment; commissions can consider these types of costs differently for recovery purposes. Commissions may allow either no or a reduced return on equity on certain assets contributing to TCs, for example. Alternatively, commissions may allow only a return of capital without any return on investment. Under this policy, shareholders would forego their equity return and might also have to pay the long-term debt return to bondholders.

Rohrbach has shown how regulatory decisions on recovery of return on investment could affect the allowed cost of a particular nuclear generating unit.[19] For the unit in question, full-cost recovery

is equivalent to 8.5¢/kWh; reducing the allowed return on equity to 90 percent of the interest rate on long-term debt lowers the cost to 8.0¢/kWh; allowing zero return on equity lowers the cost to 7.0¢/kWh; eliminating both return on equity and interest on bond payments (i.e., setting the allowed cost of capital on this unit to zero) cuts the cost to 4.9¢/kWh.

The New Hampshire Public Utilities Commission[20] and the Vermont Public Service Board[21] adopted TC positions more favorable to customers and less favorable to utility shareholders than did either FERC or California. The New Hampshire PUC noted that, with the exception of purchases from qualifying facilities, the "New Hampshire electric utilities' historical prerogative to make resource decisions have not been significantly compromised by legislators or regulators."

The New Hampshire PUC proposed to use New England regional electric rates as a key element in determining the amount of TCs that individual utilities could recover. That is, the utilities in the worst financial shape, as measured by their retail rates, will get the least relief in TC recovery. The Commission stated that

> [T]his Commission has always possessed the legal authority and duty to allow electric service to be provided through a competitive market rather than monopoly providers. Those companies with the highest rates should have reasonably anticipated their relative vulnerability as compared to companies with rates at or below the regional average. The regional average approach simply reflects the level of risk which investors in New Hampshire's electric utilities should reasonably have anticipated.[22]

The Commission reasoned that each New Hampshire utility operated under comparable economic and regulatory conditions, including participation in the same power pool, access to the same fuel markets, and the requirement to conform to the same state laws and regulations. Given these similar operating environments, it assumed that differences in utility rates are attributable primarily to utility management decisions.

In response to the New Hampshire PUC's decision, Public Service Company of New Hampshire filed for a temporary restraining order in U.S. District Court. In March 1997, the federal court in Rhode Island issued a temporary restraining order. The New Hampshire PUC then issued a stay of its February 1997 restructuring orders.

The Vermont Public Service Board is especially concerned about transition costs because rates in Vermont are increasing at the same time that they are decreasing in other New England states. The difference is primarily a consequence of the $4 billion, 30-year contracts that the Vermont utilities signed several years ago with Hydro-Quebec. These contracts account for about 60 percent of TCs for the Vermont utilities.

The Vermont Board notes that the transition to competitive electricity markets may provide "substantial *opportunities* for utilities," which can be used to offset what would otherwise be TCs.[23] The Board also plans to limit TC recovery to a five-to-ten-year transition period. It emphasizes the utilities' obligations to mitigate TC amounts and offers to provide TC recovery only after all mitigation strategies have been implemented. The 11 mitigation strategies identified by the Board include: renegotiation of power-purchase contracts; buy out or buy down of power-purchase contracts; economic operation of existing facilities and contracts; shutdown of uneconomical generating units; renegotiation of fuel-supply contracts; cost reduction; sale of uneconomical assets; write-off or write-down of uneconomical assets; appropriate load growth; exchange of underutilized assets; and refinancing of obligations through low-cost, long-term bonds (similar to the method planned for California).

The regulatory and legislative decisions in favor of cost recovery may be motivated by both philo-

sophical and practical reasons. Philosophically, the federal and California governments recognize that many of the utility decisions that led to above-market costs (especially the purchase of electricity from QFs) were actively promoted by government. Even where decisions were not promoted by governments, governments acknowledge that regulatory commissions approved those actions. The Vermont and New Hampshire decisions, on the other hand, favor retail customers over utility shareholders and emphasize the historical and legal responsibility of utility managements for their resource-acquisition decisions.

Practically, it might be very difficult to implement a new industry structure without the support of utilities. If utilities were not permitted to recover most of their transition costs, they could find many ways to delay implementation of competitive markets. For example, although the Michigan Public Service Commission mandated a retail-wheeling experiment in 1994, retail wheeling has yet to begin in that state. A utility's suit against the New Hampshire PUC's decision on TC recovery is even more dramatic evidence of what can occur when a utility believes its financial viability is threatened. Thus, we speculate that utilities in many jurisdictions will be allowed to recover most, but certainly not 100 percent, of the TCs that they cannot reasonably mitigate.

The Massachusetts DPU took just such a pragmatic view in its recent order:

> In this rulemaking, we have determined that the electric companies have not established a clear legal entitlement to stranded cost recovery. At the same time, we acknowledge that the legal question of whether stranded costs are recoverable in the restructuring of the electric industry is one that PUCs and the courts have never addressed, let alone resolved. It continues to be our belief that litigation over stranded cost recovery would delay the introduction and benefits of competition for consumers. Furthermore, as a matter of sound public policy, the Department reaffirms that allowing electric companies a reasonable opportunity to recover stranded costs is in the pub-

lic interest because such recovery would: 1) ensure the provision of sound electric services during the transition to competition; 2) affirm reliability of commitments, which is an essential element in any future industry structure; 3) promote federal and state coordination and ensure equal treatment of similarly situated utilities; and 4) avoid costly, reform-delaying litigation.[24]

In deciding on how much TCs a utility is entitled to recover from its customers, the Massachusetts DPU will require full documentation on such costs from each utility, including sensitivity analyses.

Some utilities have generating assets whose book values are *below* market prices. Although this situation of negative TCs (i.e., what one might call transition benefits) has received little attention, regulators in some states will have to decide how to allocate these benefits between utility shareholders and retail customers. Presumably, the same principles that determine the allocations for positive TCs should apply to negative TCs. As noted by the staff of the Texas Public Utilities Commission, "In the transition to a competitive retail electricity market, to the extent utilities with *positive* [TCs] are granted recovery of such costs from ratepayers or otherwise, utilities with *negative* [TCs] should likewise be required to pass through to ratepayers the benefits of their low cost generation resources."[25]

IV. Integrating Cost Recovery with Markets

Once a decision is made to allow a utility to recover some or all of its TCs, regulators need to develop an appropriate cost-recovery mechanism. The Texas PUC suggested that recovery mechanisms be assessed for their effects on rates, incentives to utilities to cut costs, effects on competitive electricity markets, and administrative simplicity. Equity and efficiency are two key criteria to consider in this regard.

Equity refers to the distributional consequences of a recovery

mechanism. A recovery mechanism should allocate costs to parties in relation to their historical obligations and expectations. As an example, a per-customer recovery charge levied without regard to the historical electricity use for each customer class (or each customer) would not pass this test.

Efficiency refers to the resource-allocation and market-operation implications of a recovery mechanism. A cost-recovery mechanism should not distort competition by affecting consumer choice among competing suppliers. Nor should a mechanism encourage high-cost generators to operate instead of low-cost units. A mechanism should not act as a barrier to entry for new suppliers (e.g., by making it profitable for an existing supplier to underprice a new entrant that has lower costs). A mechanism should encourage utilities to reduce the amount of TCs as much as possible (e.g., by retiring generating units that are uneconomical to operate and by renegotiating power-purchase and fuel-supply contracts). Finally, whatever mechanism is chosen should be simple to administer and should, to the extent possible, reduce opportunities for litigation.

A. Role of Avoidable and Unavoidable Costs

Cost-recovery mechanisms should encourage the utility to manage its generating resources in an economically efficient manner. Such decisions should depend on the avoidable (e.g., fixed O&M) and unavoidable (e.g., interest payment) components of embedded costs and should not be influenced by the form of TC recovery. Consider an example to see how these cost components should affect future decisions on generator operation or retirement and the amounts of TC recovery.

The 200-MW unit in question has variable costs (fuel plus non-fuel O&M) of 2.1¢/kWh, avoidable fixed O&M costs of $10/kW-year, and unavoidable fixed capital costs of $20/kW-year (**Table 1**). Thus, TCs should be capped at $4 million/year (200 MW at $20/kW).

The economic fate of this unit should depend on its output

(GWh produced) and on the price it receives for that output. Assume that market conditions allow this unit to sell its output on the spot market for 2500 hours a year at an average price of 3.0¢/kWh. The unit's revenues amount to $15 million. Variable costs (200 MW x 2,500 hr x 2.1¢) account for $10.5 million, leaving $4.5 million to cover fixed costs. This $4.5 million is greater than the $2 million avoidable fixed cost, which suggests that it is economical to operate this unit. The $2.5 million remaining after avoidable fixed costs are paid can be used to offset TCs. Thus, this unit has transition costs of $1.5 million this year.

If the region had more generation on line than implied above, the unit might be able to operate for only 1,500 hours a year, receiving only 2.6¢/kWh for its output. In this case, the unit's revenue of $7.8 million would leave only $1.5 million after covering variable cost. This amount is insufficient to pay for avoidable fixed costs, suggesting that this unit should be shut down. (Whether the utility should permanently retire the unit or mothball it for a few years would depend on its assessment of future market conditions.) In this case, the TCs are capped at $4 million, the unavoidable capital costs. The utility would *not* recover the full $4.5 million loss it would incur if it continued to operate the unit.

If, however, the amount of capacity in the region is limited relative to demand, the unit might operate for 3,200 hours at 3.1¢/kWh. In this case, revenues would be sufficient to cover all the unit's costs, and TCs would amount to -$400 thousand (i.e., a negative TC). This amount should be used to offset losses associated with other generating units.

This example shows that the amount of TCs associated with a particular generator depends on the interactions between that unit and the competitive bulk-power market. It also suggests that regulators need to be careful in designing a TC-recovery mechanism to be sure that it does not distort what would otherwise be economically efficient decisions concerning the operation, shutdown, or retirement of the unit.

Table 1: Hypothetical Example Showing Relationship between Avoidable and Unavoidable Fixed Costs, and Allowable Transition Costs[a]

	Bulk-power market conditions		
	Base	Excess capacity	Little capacity
Unit operations			
Hours/year	2,500	1,500	3,200
Price received	¢/kWh	3.0	2.6
Revenues and costs (thousand $/year)			
Revenues	15,000	7,800	19,840
Variable cost	10,500	6,300	13,440
Net revenue	4,500	1,500	6,400
Avoidable fixed cost	2,000	2,000	2,000
Net revenue	2,500	-500	4,400
Unavoidable fixed cost	4,000	4,000	4,000
Net revenue	-1,500	-4,500	400
Maximum allowable TC	1,500	4,000	0

a. This 200 MW generating unit has fuel plus variable O&M costs of 2.1¢/kWh, avoidable fixed O&M costs of $10/kW-year, and unavoidable fixed (capital) costs of $20/kW-year.

B. Recovery Period

Regulators need to decide on the time period during which utilities will be allowed to collect TCs from their customers. A short recovery period (e.g., the four-year period for utility-owned generation to be used in California) provides for a rapid resolution of these issues and a prompt transition to a fully competitive electricity industry. On the other hand, a recovery period tied to the book and economic lifetimes of the underlying assets and liabilities matches cost recovery with cost incurrence. This type of approach might require TC payments for 20 or more years (e.g., until all power-purchase contracts have expired and all utility generating assets have been retired).

Another complication concerning the time period for TC recovery concerns the possible change from positive to negative TCs. As illustrated in **Figure 1**, a utility's fixed generation costs are almost certain to decline from year to year. Competitive pressures may also lower variable costs over time. On the other hand, as electricity demand grows and uneconomical generating units are retired, market prices may increase. At some point (2005 in the illustration), the utility's losses will become gains. If the state regulator allows, say, an eight-year recovery period from 1996 through 2003, the utility will be allowed to recover all of its TCs. It will face unrecovered TCs in 2004, but will then enjoy *negative* TCs (i.e., increased earnings) in subsequent years until the assets and liabilities are retired.

IV. Conclusions

The U.S. electric-utility industry is in the midst of major changes. These changes include deintegration of the industry and substantial increases in competition within the generation and customer-service sectors of the industry. A major consequence of these changes is the exposure of transition costs. These costs, which could amount to $100 to $200 billion nationwide, reflect the differences between the regulated prices for electricity generation and the prices that might occur in competitive power markets. These above-market costs are associated with past costs (e.g., in construction of power plants that turned out to be expensive or to provide more capacity than needed) and future obligations (e.g., long-term fuel-supply and power-purchase contracts).

The large financial stakes, comparable in magnitude to the total value of U.S. electric-utility common stock, guarantee controversy. Debates occur over transition-cost amounts; analytical and market methods to estimate these costs; the assets and liabilities to include in such calculations; the assumptions used in developing these estimates; approaches that can be used to offset at least some of these costs; the ultimate allocation of the remaining costs among utility shareholders, different classes of retail customers, independent power producers and other wholesale suppliers, and taxpayers; and appropriate cost-recovery mechanisms.

Competition does not create transition costs. Rather, it exposes these costs and makes them a visible source of conflict among different market participants as to who will bear these costs in the future. We call these costs transition costs to emphasize that they are not a permanent feature of a competitive electricity industry. Once dealt with—no easy task for regulators—they will no longer be an issue.

To date, governments have differed in their approaches to allocating the remaining, non-mitigable transition costs. The Federal Energy Regulatory Commission and the State of California, perhaps in recognition of the key role that today's utilities will play in the transition to a fully competitive electricity industry, decided to allow utilities the opportunity to recover their legitimate, verifiable, non-mitigable, and prudent transition costs. Vermont and New Hampshire regulators, on the other hand, emphasized the importance of utility mitigation of as much of the transition costs as possible. These two states, in balancing the interests of utility shareholders and retail customers, favored customers more than did FERC and California.

Having decided how much of its transition costs a utility should be allowed to recover, regulators now need to implement workable cost-recovery mechanisms. Such mechanisms should encourage competition in the generation sector and should neither favor nor

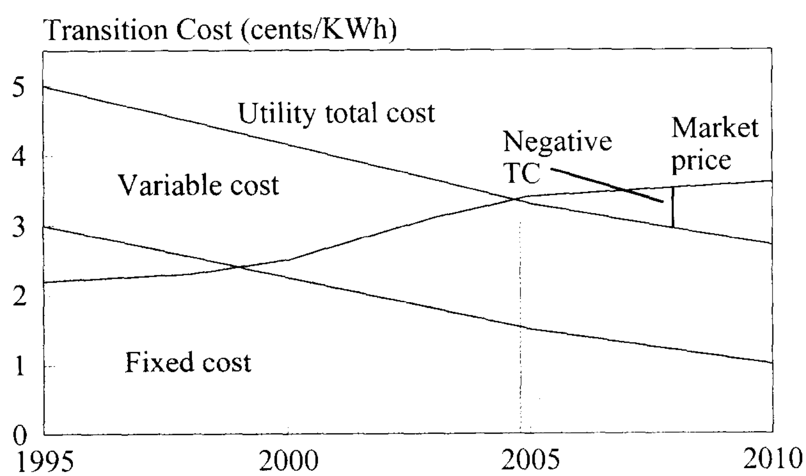

Figure 1: Hypothetical Transition Costs Over Time

hamper the decisions of utilities, independent power producers, and customers. In other words, the cost-recovery mechanism should not affect supplier decisions on electricity production and should not affect customer decisions on how much electricity to consume and from whom to buy that electricity. Cost-recovery mechanisms should give utilities the same incentives that other electricity suppliers face to cut costs and innovate. ■

Endnotes:

1. Fed. Energy Reg. Comm'n 1997, Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities (March 4, 1997) (Order on Rehearing, Docket Nos. RM95-8-001 and RM94-7-002, Order 888-A). *See also* Fed. Energy Reg. Comm'n, Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities (April 24, 1996) (Final Rule, Docket Nos. RM95-8-000 and RM94-7-001, Order 888).

2. L. BAXTER, E. HIRST, AND S. HADLEY, TRANSITION-COST ISSUES FOR A RESTRUCTURING U.S. ELECTRICITY INDUSTRY (ORNL/CON-440, March 1997).

3. W. Baumol, P. Joskow, and A. Kahn, The Challenge for Federal and State Regulators: Transition from Regulation to Efficient Competition in Electric Power (Edison Electric Inst., Dec. 9, 1994).

4. *See also* Paul L. Joskow, *Does Stranded Cost Recovery Distort Competition?*, ELEC. J., April 1996, at 31.

5. John Rowe and Paige Graening, *Property Law: It's Physical and Logical*, ELEC. J., Aug./Sept. 1996, at 44. An exchange of letters between Randazzo and authors Rowe and Graening in the Oct. '96 issue of *The Electricity Journal* indicate how complicated and contentious these constitutional issues are. *See* S. Randazzo, *Muddling Stranded Costs?* ELEC. J., Oct. 1996, at 5 (letter) , and Rowe and Graening response at 85. *See also* Mass. Dept. of Pub. Util., Electric Industry Restructuring Plan: Model Rules and Legislative Proposal (Dec. 30, 1996) (D.P.U. 96-100).

6. Rowe and Graening, *id.*, at 49.

7. A. L. Kolbe and W. B. Tye, *Compensation for the Risk of Stranded Costs*, 24 ENERGY POLICY, 1025-50 (Dec. 1996).

8. *See*, e.g., IPALCO Enterprises, Inc., Restructuring the Electric Utility Industry, The Real Problem and the Real Solution: Customer Choice Through Universal Access (Indianapolis, Ind., Nov. 1995).

9. P. Navarro, *Electric Utilities: The Argument for Radical Deregulation*, HARV. BUS. REV., Jan./Feb. 1996, at 112. Another commentator notes that almost all of the stranded nuclear investment comes from 34 plants that were completed after 1984. By that time, Michaels argues, utilities should have known that such plants were far too costly to build and, in many cases, were not needed at all. R. J. Michaels, *Stranded Investments, Stranded Intellectuals*, REGULATION, 1996, no. 1, at 47.

10. K. ROSE, AN ECONOMIC AND LEGAL PERSPECTIVE ON ELECTRIC UTILITY TRANSITION COSTS (Natl. Reg. Res. Inst., NRRI 96-15, July 1996).

11. P. A. Bradford, *Til Death Do Us Part or the Emperor's New Suit: Does a Regulatory Compact Compel Strandable Investment Recovery?* PUB. UTIL. Q. (3rd Q., 1996).

12. Michaels, *supra* note 9.

13. Council of Economic Advisers, *Promoting Competition in Electricity*, ECONOMIC REPORT OF THE PRESIDENT (U.S. Government Printing Office, Feb. 1996).

14. *Supra*, note 1.

15. Calif. Pub. Util. Comm'n, Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation (Dec. 20, 1995) (R.94-04-031, Decision 95-12-063) (later modified by Decision 96-01-009, Jan. 10, 1996).

16. California Legislature, Assembly Bill 1890, Ch. 854, Statutes of 1996 (Sept. 1996).

17. Pa. General Assembly, The Electricity Generation Customer Choice and Competition Act, HB 1509 (Nov. 20, 1996).

18. Statement of Commissioner John Hanger, Investigation into Electric Power Competition (Pa. Pub. Util. Comm'n, July 3, 1996).

19. J. Rohrbach, Calculating Utility Stranded Generation Investment (Pa. Pub. Util. Comm'n, Dec. 6, 1996).

20. N.H. Pub. Util. Comm'n, Restructuring New Hampshire's Electric Utility Industry: Final Plan (Feb. 28, 1997) (DR 96-150).

21. Vt. Pub. Serv. Bd., The Power to Choose: A Plan to Provide Customer Choice of Electricity Suppliers (Dec. 30, 1996) (Docket No. 5854).

22. N.H. Pub. Util. Comm'n, *supra* note 20, at 77.

23. The Massachusetts Department of Public Utilities (1996) also notes that today's utilities have certain competitive advantages, such as "substantial physical assets including plant, equipment, and sites acquired over the monopoly period, and largely financed by ratepayers; and, in some cases, intangible assets, such as name recognition and customer loyalty." Mass. Dept. of Pub. Util., *supra* note 5, at 247.

24. Mass. Dept. of Pub. Util., *supra*, note 5, at 264-65.

25. Texas Pub. Util. Comm'n, Report to the 75th Texas Legislature, Volume III: Potentially Strandable Investment (ECOM) Report: A Detailed Analysis (Jan. 1997).