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AN ECONOMIC AND LEGAL PERSPECTIVE ON ELECTRIC UTILITY TRANSITION COSTS

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EXECUTIVE SUMMARY

The issue of possibly unrecoverable cost incurred by a utility, or "stranded costs," has emerged as a major obstacle to developing a competitive generation market. Stranded costs or transition costs are defined as costs incurred by a utility to serve its customers that were being recovered in rates but are no longer due to the availability of lower-priced alternative suppliers. The idea of "stranded cost," and more importantly arguments for its recovery, is a concept with little basis in economic theory, legal precedence, or precedence in other deregulated industries. The main argument for recovery is that the "regulatory compact" requires it. This is based on the misconception that the regulatory compact is simply: the utility incurs costs on behalf of its customers because of the "obligation to serve" so, therefore, customers are obligated to pay. This is a mischaracterization of what the compact was and how it developed. Another argument is that recovery is required for economic efficiency. This presumes, however, a very narrow definition of efficiency based on preventing "uneconomic" bypass of the utility and that utilities minimize costs. A broader definition of efficiency and the likelihood of cost inefficiencies in the industry suggest that the cost imposed on customers from inhibiting competition could exceed the gains from preventing uneconomic bypass. Both these issues are examined in more detail below.

Economic Efficiency

There are two general types of economic efficiency: productive or "static" efficiency and a more comprehensive or "dynamic" efficiency. *Static efficiency* is achieved when power is generated by the lowest-cost producer; that is, there is only economic bypass of the utility's system and no "uneconomic" bypass. The marginal costs of the utility and alternative supplier and utility rates are assumed to remain unchanged and are optimal (all costs are minimized and there is no market power). *Dynamic efficiency*, in contrast, assumes that the utility's marginal cost can or does change over time and, if not optimal as might be expected under rate-of-return regulation, can be reduced through the use of market incentives. Competitive markets are by nature dynamic where competitors are driven to control costs to retain or attract customers (as long as it is profitable or is expected to be).

Dynamic-efficiency gains are potentially much larger than any static-efficiency losses. This is because the loss from “uneconomic” bypass, which only occurs in a limited quantity range, will likely be less than the gain to consumers from price reductions. If the intention is to facilitate the development of a dynamic competitive market, preference should be given to policy options that encourage dynamic efficiency and policies that impair it should be avoided. This cannot be achieved by just focusing on static-efficiency losses. The only time static efficiency should be pursued in isolation is when generators of electricity are optimally producing electricity at minimum cost; an unlikely assumption given that the starting position is cost-based regulation. The best way to achieve optimal dynamic efficiency is with unencumbered market incentives.

Specifically, allowing recovery of transition costs can negatively affect dynamic efficiency and impair the development of a competitive market in the following ways.

(1) *Blunts utility incentives to lower costs and mitigate transition costs*. For utilities that receive transition cost recovery this could occur primarily because the regulator, who has incomplete or imperfect information, is unable to detect when opportunities to reduce costs are not taken, are not the best alternative, or are not pursued to full advantage. At its worst, paying transition costs causes a perverse incentive to utilities to find and argue for recovery of all potential costs rather than lowering costs to become competitive (including costs that may not be appropriate for recovery). This institutionalizes existing utility uneconomic costs and rates rather than encouraging a phasing out of these uneconomic and inefficient costs.

(2) *Acts as a barrier to entry and exit*. Whether through entrance, access, or exit fees, recovery of a utility's sunk costs creates a barrier to entry.

Efficient suppliers are discouraged from expanding or entering the market. Inefficient utilities are instead subsidized to continue to be the supplier or, if another supplier is chosen, to support assets that no longer have an economic or market value equal to its accounting or embedded value. In addition to the higher costs that customers are forced to pay, this leads to inefficient self-generation as customers seek ways to avoid the fee. This is another form of uneconomic bypass, but is not prevented by an access fee since the fee itself is bypassable.

(3) *Creates an asymmetry between utility risk and reward*. A risk/reward asymmetry is created if a commission allows a utility to retain more profit than in the past, but simultaneously guarantees that any potential down-side loss from competition will be recovered from customers. Commissions have indicated thus far in the restructuring debates that higher profits will be allowed from competition and performance-based regulation. Allowing more up-side potential profit while limiting the down-side risk distorts a utility's incentive in such a way that it would be less cautious than it would be when the utility incurs a loss itself. Many utilities — perhaps even most — are likely to receive gains as a result from open and retail access and from a broader use of market-based rates. To make provisions for possible losses that the industry will incur without considering the possible substantial gains adds to the regulatory asymmetry. For this reason, transition cost recovery may conflict with the goal of increasing the use of performance-based regulation.

The Regulatory Compact

An examination of the origins and content of the regulatory compact finds little basis for the claim that utilities are always entitled to cost recovery and a return on their investments. Indeed, a strong argument could be made that to be consistent with past treatment and the manner in which the compact has been interpreted by many states, *full* recovery of transition costs would be inconsistent. There is no "entitlement" to "stranded" cost expressed or implied by the regulatory compact. The only entitlement granted was the revocable privilege to serve an exclusive territory. The obligation to serve stems from this privilege. The compact is not an agreement to pay all costs (prudent or otherwise) because of the obligation to serve. It is much more complex than simply "I am obligated to serve, therefore customers are obligated to pay all my costs." There is no reciprocal obligation on customers to buy, unless there is a written contract.

A description of this regulatory agreement or bargain as historically interpreted, may be as follows: the careful balance between compensatory rates and confiscation of utility property that allows a utility an opportunity to earn a reasonable return on investment in exchange for providing safe and reliable power at reasonable cost to all customers who request service. This is checked by the "used-and-useful" and "prudent-investment" tests, as well as from competition from government ownership, fuel substitutes, and self-generation. The regulatory compact was, by design, intended to protect ratepayers from monopoly abuse, not protect the utility from competition forever.

The debate on transition costs thus far implies that the commission or legislature imposes costs on the utility when it moves to open or direct access, or that regulators or customers *cause* costs. This has shifted the focus away from the origin or controller of these costs, the utility. In an economic sense, retail access and competition do not impose costs — rather they *expose* costs that are uneconomic relative to alternative suppliers. In many respects, it is the tariff or rate that is "stranded," not the investment. An important function of competitive markets is to screen out costs and suppliers that have above-market prices. These may include costs that would have remained hidden if the utility's monopoly was allowed to continue. It is important to remember that the regulatory compact was created originally to protect ratepayer interests, not primarily utility interests.

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FOREWORD

Few subjects have dominated discussion in electric utility regulation as has the issue of "stranded cost recovery." Sides have been chosen and arguments for permitted recovery from ratepayers range from zero to full. The present study critically appraises the main arguments made for substantial recovery of these costs by utilities — economic theory, legal tradition, precedence with other deregulated industries, and regulatory obligation — and finds them generally wanting. Our report is offered as a reasoned contribution to the debate.

Douglas N. Jones
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July 1996

CHAPTER 1

INTRODUCTION

There is no doubt that a utility that is allowed recovery of its transition costs[1] will behave differently than a utility that is not allowed recovery. How the question of transition cost recovery is resolved will have a major impact on the savings actually realized by consumers from industry restructuring. Recovery or nonrecovery will affect every future decision the utility makes. This includes new investments and contract renegotiation for fuel, wholesale power, and nonutility power producers (such as qualifying facilities). Recovery of transition costs may discourage alternative suppliers from entering a market, thus reducing the competitive pressure on the incumbent utility. Large consumers who have choices (and perhaps groups of smaller customers) may make poor resource decisions to avoid fees to recover costs, such as self-generation when central station power has a lower production cost. Another example of the consequences may be to alter the direction of new generation and distribution technologies toward more decentralization rather than large central systems. The decisions that policy makers make now will have a profound impact on the development, direction, and actual savings realized from the nascent competitive generation market.

Because the electricity market is in the early stages of its development, actions taken now by policy makers will have a more significant impact on the market and how it develops than they would with a mature market. For both consumers and producers this could mean the difference of billions of dollars of savings or costs. In addition,

[1] The term "transition cost" is used here rather than the more popular "stranded cost," since it is neutral as to outcome and conveys the temporary nature of these costs. This is not intended to suggest that the transition causes these costs. Rather, these costs are revealed during the transition to more competition.

once any policy has been put in place it becomes difficult to change. New and existing market participants, including many that have yet to be identified, rapidly become adapted to the conditions and begin to look at their benefits as an entitlement. This makes change politically difficult. Moreover, once the motivation for policy change is gone, it may not return for many years.

The potential benefits to producers and consumers from a competitive market are considerable. One report concluded that "permanent benefits to be gained from restructuring of the US electric supply industry vastly outstrip the transitional costs associated with the restructuring."[2] The authors of this report estimate the net benefit (to both consumers and producers) of restructuring to be $80 to $100 billion *per year*.[3] A report by Moody's Investors Service[4] estimates "stranded" costs at $135 billion *total*. This does not mean that the problem of transition costs will simply be absorbed, but rather underscores the importance, and the consequences, of a mistake that could be of a significant magnitude. Also, the problem is mostly concentrated in a relatively small group of utilities. The fact that there may be significant savings overall, does not help those companies in particularly serious trouble. In the Moody's study, fourteen firms (out of 114 companies examined) had transition costs in excess of 200 percent of their equity capital.

However, it should be noted that twenty-seven utilities had no transition costs at all (which, presumably, will have competitive gains rather than losses) and fifty-seven were under 50 percent of equity. This is based on a methodology that will tend to overstate the amount of transition costs. The reason for this, as will be explained in Chapter 2, is that the estimates are based on existing cost structures that are likely not

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[2] Chitru Fernando et al., "Unbundling the US Electric Power Industry: A Blueprint for Change," report prepared for Enron Capital & Trade Resources, Houston, Texas (March 1995).

[3] This is a considerable sum, to say the least. Even if actual savings turn out to be one-half or one-quarter of this, it is still quite respectable.

[4] *Stranded Costs Will Threaten Credit Quality of U.S. Electrics* (New York: Moody's Investors Service, August 1995).

to be optimal and do not account for the dynamic effects of utility responses to competition, such as cost reductions. This is in addition to the difficulty in estimating a future market price of power. These estimates are likely a worst-case scenario.[5] Another study that considered competitive gains for major Massachusetts electric utilities concluded that, on *net*, there would be competitive gains not losses, as utilities claimed, in the state.[6] The study concluded that market valuation for most utility generation assets will exceed net investment. In addition, for Massachusetts utilities that do have a net loss, it is only a small fraction of total net investment. For many utilities in the country, it is safe to assume, there will be gains from competition not losses.

Organization and Scope of the Report

There are several dimensions to the problem of "stranded" or "transition" costs. In broad terms they are:

- the source of the problem,
- the magnitude of the amount, nationally and for individual utilities,
- allocation or who pays, and
- if any transition costs are recoverable, how should they be recovered.

Thus far, the size of the problem and who should pay have dominated the debate. Numerous studies have addressed the problem of the size of the problem, both

[5] Moody's believes that they understated the amount because they omit contract costs and because their market price may be too high. They do not mention expected utility operating cost reductions or other likely responses.

[6] Paul Chernick et al., *Estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities*, prepared for the Massachusetts Attorney General (April 1996).

nationwide and for individual states and utilities.[7] Other studies have covered the topic of recovery mechanisms for transition costs[8] and methods to measure them.[9]

This report is focused on the source and allocation of transition costs. When considering these issues, a commission may ask the following questions: Should a utility be allowed to recover costs that are revealed to be uneconomic with competition? What consequences will this decision have on the utility and the development of competitive markets? What type of treatment is consistent with past regulatory actions?

Arguments both supporting and opposing transition cost recovery often rest on two main pillars: economic efficiency and the regulatory compact. It is important to first understand how the problem comes about before a means to evaluate policy options can be developed to deal with them. A solid understanding of the economics of the problem provides insight into a means to evaluate alternative regulatory treatments and a means to understand the other questions of size and recovery. The next chapter focuses on the economics of transition costs in the electric utility industry.

Chapter 3 examines the origins and definition of the "regulatory compact." At issue is whether not allowing recovery is an unconstitutional "takings" of utility property and violates past commitments made by regulators. To determine this, the history and development of the compact and analogous regulatory issues are examined. The principle of regulatory symmetry is examined as to how it could be applied to developing a transition cost treatment. Chapter 4 then examines the issue of utility and investor expectations of competitive risk and presents a method to determine whether

[7] See for example, Lester W. Baxter and Eric Hirst, *Estimating Potential Stranded Commitments for U.S. Investor-Owned Electric Utilities*, ORNL/CON-406 (Oak Ridge, TN: Oak Ridge National Laboratory, 1995); Moody's Investors Service, *Stranded Costs Will Threaten Credit Quality of U.S. Electrics*; and Chernick et al., *Estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities*.

[8] Specific methods of treating transition costs are discussed in Scott Hempling, Kenneth Rose, and Robert E. Burns, *The Regulatory Treatment of Embedded Costs Exceeding Market Prices* (Columbus, OH: The National Regulatory Research Institute, November 1994); and Lester W. Baxter, Stanton Hadley, and Eric Hirst, *Strategies to Address Transition Costs in the Electric Industry*, Draft Report (Oak Ridge, TN: Oak Ridge National Laboratory, April 1996).

[9] Lester W. Baxter, *Different Approaches to Estimating Transition Costs in the Electric-Utility Industry*, ORNL/CON-423 (Oak Ridge, TN: Oak Ridge National Laboratory, 1995).

investors have been compensated for the increased market risk from competition. The final chapter proposes a performance-based mechanism that is symmetrical in its treatment of profits and losses and provides better utility incentives to control costs, that is, if it is decided that recovery will be allowed. If it is decided that utilities can recover transition costs, a list of recommended commission actions is suggested.

Transition cost determination and allocation are complex and contentious issues. Because of the amount of money at stake, both for customers and producers, it is likely to remain an important topic on commission agendas for some time. As is often the case with complex and contentious issues, however, the courts may ultimately decide the outcome (this issue has already, or is about to, reach the courts in several states). This underscores the need to throughly examine the issue and make a decision based on sound principles, not suppositions.

CHAPTER 2

THE ECONOMICS OF ELECTRIC UTILITY TRANSITION COSTS

The debate on how to treat transition costs is exclusively a regulatory phenomenon. There is no direct analogy to private and unregulated markets or any economic textbook definition of transition costs with suggestions on how they should be treated. However, a definition and analysis can be developed from economic "first principles." Using standard cost curves this chapter develops an economic model of transition costs to help illuminate the issue. This is followed by a discussion of the source of transition costs for electric utilities and economic efficiency.

In a competitive market, any obsolete or uncompetitive plant and equipment costs (or sunk costs) are disposed of at market value, any difference between market value and book value is absorbed by the firm's shareholders or owners (and, to a limited extent, taxpayers because the loss can be used to offset taxable income). This results in lower earnings, which the shareholders or owners of the firm are willing to endure if there is an expectation of earning an adequate return on their investment later. Alternatively, the firm simply goes out of business and its assets are sold off. First creditors, then stockholders are paid the amount owed or invested until the available funds are exhausted. Obviously, many do not receive the full amount owed or invested. This is the risk they undertook to earn a return on their investment. These costs cannot be passed through to customers since, in the competitive market, firms can only charge the market price. A firm that charges a price above market price will lose customers and be driven out of business by more efficient firms. Investors, of course, are only willing to invest if they believe that they will receive the expected return. Thus, there is a direct relationship between the return on investment and the probability of a loss or the investment's relative risk. A relatively higher return is required for riskier investments, while lower-risk investments pay a lower return. This will be discussed in more detail in Chapter 4.

In a dynamic competitive market economy, assets become obsolete and are abandoned regularly. An important function of a market economy is that inefficient and obsolete practices and firms are either eliminated and replaced with more efficient and superior firms or forced to redirect their efforts to become more efficient and better managed. Overall this results in society's limited resources being used in a productive manner. This limits waste and strengthens the overall economic health of the country. Rarely is there a third party to "bail out" a firm that faces possible losses and financial ruin.[1] Indeed, doing so only hampers this screening process of a market economy. Of course, because of government or market failure, this process may be inhibited or distorted. For example, because environmental costs are not fully included in oil prices, consumers do not face the true resource cost of the gasoline they consume. This distortion reflects both political as well as market effects.

The main economic argument for permitting more competition for electric generation is to encourage just such dynamic economic efficiency. Competition, or the possibility of utility "bypass," encourages utilities to reduce their costs to remain or become more competitive, if utilities are allowed to adjust their rates to remain competitive and alternative suppliers are allowed to compete. Already there have been cases of utilities lowering rates to retain industrial customers and municipalities that border a neighboring utility with lower rates. Industrial and large commercial customers with the added option of self-generation, have also been negotiating lower rates.

The problem faced by electric utility regulators is, of course, that the industry is moving from vertically-integrated regulated monopolies to a more competitive structure. When utility rates are above market prices, there will be pressure either to switch to the lower-cost source or for utilities to lower their rates. As competition intensifies, transition costs are likely to result. Of course, not all utilities are in the position of having transition costs. In fact, the competition may often come from a neighboring utility with lower costs who will benefit from increased competition. There may be many

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[1] There are some famous examples of government bailouts such as Lockheed Aircraft, Chrysler, and the Savings and Loan industry. However, these are exceptions to the general rule of how such firms are dealt with in a market economy.

more "winners" than "losers" in a competitive electric market. The following discussion is intended to assist in the development of methods to deal with transition costs in an economically efficient manner.

Bypass Economics and Transition Costs in the Electric Industry

A Simple Comparative Statics Model

To begin the analysis, a simple model is developed to describe utility and alternative supplier relative market positions and the optimal combination of output from the two sources. This model is then used to conduct a comparative statics analysis of transition costs in equilibrium and disequilibrium and when cost assumptions change.

Figure 2.1 illustrates a hypothetical utility's marginal cost and average revenue (or the average rate for all customer classes) and an alternative power supplier's marginal cost.[2] The utility's marginal cost curve for generation is MC_u.[3] This is the marginal cost of generation only, and does not include distribution, transmission, and the cost of other services the utility provides. Generation is, in effect, "unbundled" from other utility operations. For the output range examined below, marginal cost (average cost is not shown in this diagram but will be in the next) is shown rising. This firm is operating in the range where marginal cost is greater than average cost. This means

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[2] It is assumed here, for clarity, that there is only one alternative supplier. Of course, there are likely to be many alternative suppliers, including independents, other utilities, and self-generators. The results of the analysis would not change, however, if alternatively, all marginal cost curves were drawn, it was assumed that the MC_a curve is a composite of all alternative suppliers, or the curve represented the lowest-cost alternative.

[3] Generally, electric generation is characterized as being "lumpy" with discontinuous jumps in marginal or incremental costs. Depicting marginal cost in a stair-step or discontinuous manner would not change the conclusions. The continuous function was chosen for clarity of the diagram.

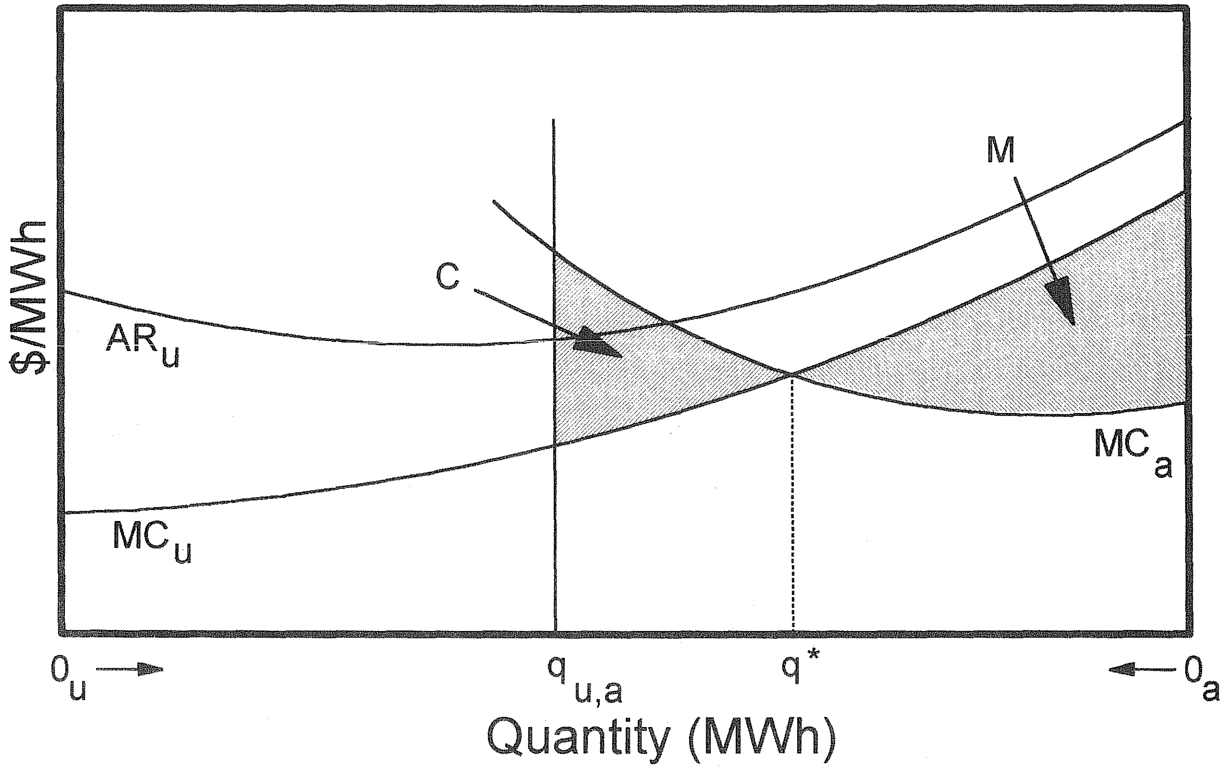

Figure 2.1. Hypothetical utility's marginal cost and rate curves compared with an alternative supplier's marginal cost.

that fixed or capital costs are recovered when rates are at or above average costs.[4] The upward sloping portion of the curve is shown since it is assumed that for most firms, generation economies of scale have been exhausted (where average cost is

[4] Average cost has two components, average variable costs and average fixed costs. This second component of average cost, as discussed below, is an important factor when determining a utility's total transition costs. Since it is assumed that average generating costs are rising (for the relevant output), the marginal cost will be greater than average cost, and fixed costs are recoverable if the firm receives a price at least equal to its marginal cost.

falling) for large quantities of power and for most firms.[5] The utility's average revenue curve or its rate is AR_u.[6] This is drawn as a approximation of the average cost curve for providing all electric services.[7] This includes generation, distribution, transmission, and other provided services.

The marginal cost of an alternative supplier is depicted by MC_a. The alternative's marginal cost curve represents the cost of generating power within the existing electric supply infrastructure. This curve is drawn with its origin at the lower right axis on this diagram. The alternative power could be supplied by another utility or independent generator within the utility's service territory. MC_a is drawn as an upward sloping marginal cost curve, where the first few megawatthours (MWhs) generated would have a relatively low marginal cost and remain relatively flat for some range and then gradually increase. This is characteristic of the "modular" power units now available to industrial and other independent power producers, where additional energy production costs are relatively flat over a range of output, but is limited. It is assumed here that the price charged by this alternative supplier is equal to its marginal cost, as would be the case in a competitive market.[8]

The horizontal axis represents different combinations of utility and alternative power supply that satisfy the total demand for power (which is determined exogenously). For example, the quantity 0_a is the point where all the demand is met by

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[5] The firm is shown here to be operating in the region of increasing average costs. This is because recent evidence suggests that, for most firms, they are operating at an output where average cost is constant or increasing. See Thompson et al., *Economies of Scale and Vertical Integration in the Investor-Owned Electric Utility Industry* (Columbus, OH: The National Regulatory Research Institute, 1996). If the diagrams instead depicted decreasing average and marginal costs, however, the analysis and conclusions would not change. For reasons of clarity, the entire downward portion of average cost is not depicted in the diagrams.

[6] Average revenue and rate are the same since average rate equals (rate x quantity)/quantity, which equals rate. The term average rate is used here to simplify the fact that different customer classes pay different rates calculated from total revenue requirement.

[7] Since the average rate is rising, it would be expected that demand for power would decrease. However, for ease of exposition, it is assumed here that demand is perfectly inelastic. Since this graph represents an instant in time, this is a reasonable assumption.

[8] This can also serve as a proxy market price with multiple suppliers or the alternative supply curve. Again, in this example, there is assumed to be only one alternative supplier.

the utility and no power is provided by the alternative supplier, 0_u is the alternative supplier providing all the power and no utility power, while $q_{u,a}$ (and all other points between 0_u and 0_a) is a combination of the two suppliers. The quantity q^* would be the optimal combination, that is, where marginal cost and supplier cost are minimized.[9] The area M is the higher costs that would be incurred if there was no alternative supplier and all power was supplied by the utility. Therefore, M represents the "gain from competition." The area C is the higher costs incurred from too much alternative power if demand was satisfied at quantity $q_{u,a}$.

Figure 2.2 shows the amount of transition costs when the utility previously supplied all the demand (quantity 0_a) but now supplies at the optimal quantity q^*. To illustrate transition costs, the figure also includes the firm's average cost (AC_u) and average variable cost (AVC_u) in addition to the curves shown in Figure 2.1. The difference between average cost and average variable cost is average fixed cost (this is because AC = AFC + AVC or AFC = AC - AVC). This is the utility's transition or "stranded" investment costs and is shown by the area F. (This assumes that the utility does not sell the power elsewhere in another market.) The area T is other costs that are potentially not recoverable from selling generated power. This includes transmission and distribution costs, system support costs (or ancillary services), and other related costs. Many of these costs would be recovered by the utility when it supplies these services to the alternative supplier since the utility will remain the only supplier of many (but perhaps not all) of these services.

The only potentially "stranded" investment (or sunk) cost, and the main point of contention in the debate on recovery, is the area indicated by F. This area represents the fixed generation cost of the utility that is no longer recovered from customers when bypass occurs. The area T, however, represents other system costs that (except for

[9] Only generation costs are considered in this analysis. Other costs to society in general (that is, external costs) are not considered here. For a discussion on the treatment of external environmental costs, see Kenneth Rose, Paul A. Centolella, and Benjamin F. Hobbs, *Public Utility Commission Treatment of Environmental Externalities* (Columbus, OH: The National Regulatory Research Institute, June 1994).

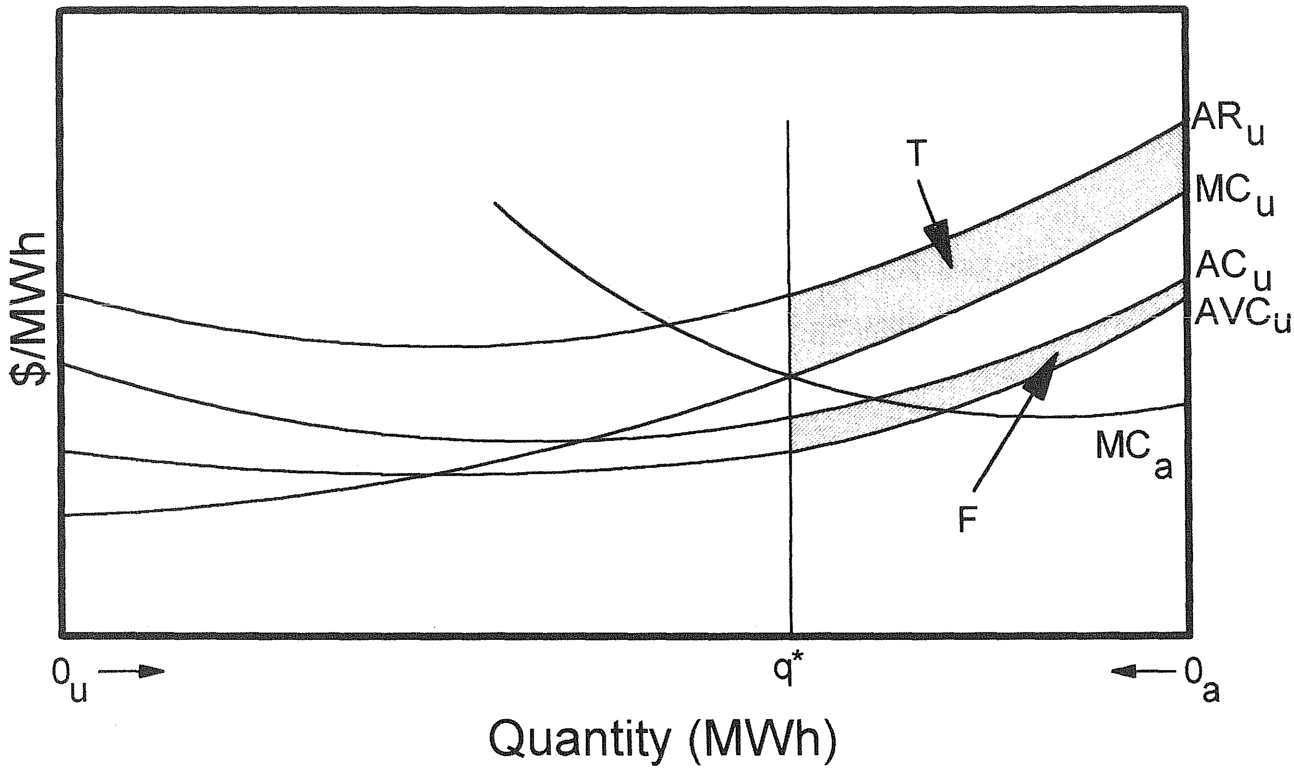

Figure 2.2. Area of nongeneration unrecovered cost and unrecovered average fixed cost with bypass.

system costs that are not "used and useful" that may still be in rates), are needed to reliably supply power to customers, are services that the utility will maintain a monopoly of, and are recoverable through exit, access, or entrance fees. All other costs below the utility's marginal cost are not incurred when the utility is no longer suppling the generation. Again, if the utility is at the quantity q^*, or at any point in the range where marginal cost is greater than average cost, all fixed costs are below marginal cost. Any calculation of transition costs should recognize those variable or marginal costs that are avoided when generation is reduced and any revenue from the sale of system (nongeneration) services. In the calculation of transition costs, therefore, both the avoided generation costs (costs not incurred) and revenue from the sale of system services (otherwise the utility could collect revenue for these services twice) should be subtracted from the lost revenue requirement of the utility. Once this calculation is made, the debate on how much of area F the utility should recover can proceed.

Figure 2.3 depicts two nonoptimal quantities of power production by the utility and alternative supplier using the same cost assumptions as in the previous two figures. The first case, where quantity equals q_1, is an example of too much or "uneconomic" bypass (all quantity combinations to the left of q^* represent uneconomic bypass). The alternative's marginal cost is above the utility's marginal cost but below the utility's average revenue between q^* and q_1. In this range, potential customers comparing the utility's rate with the alternative's price (or marginal cost) will choose the alternative even through the utility's marginal cost is lower. This effect only occurs in the region between q^* and q_1. In the strict productive efficiency sense, bypass of the utility would be inefficient since the lowest-cost supplier is not selected by customers. The potential loss to consumers is the triangular region L between the utility's and the alternative's marginal cost.

Note that if bypass did occur, the utility would again avoid incurring the variable costs associated with producing the power. The amount of unrecovered cost is the average rate minus the utility's marginal generation cost, or area T (including L), plus the fixed or capacity portion of the utility's average generation cost, AC_u - AVC_u, or the area F. Both these areas are now greater than that depicted in Figure 2.2.

To avoid the problem of uneconomic or inefficient bypass, the cost of transmission and distribution and other system costs represented by the region T, can be added to the alternative supplier's marginal cost, through an "access charge" for example; this is shown by the new curve, MC'_a, in Figure 2.3. In this case the supplier with the lowest generation cost will be selected by customers, even in the region q^* to q_1. Outside of this region, the access charge is not necessary for selection of the

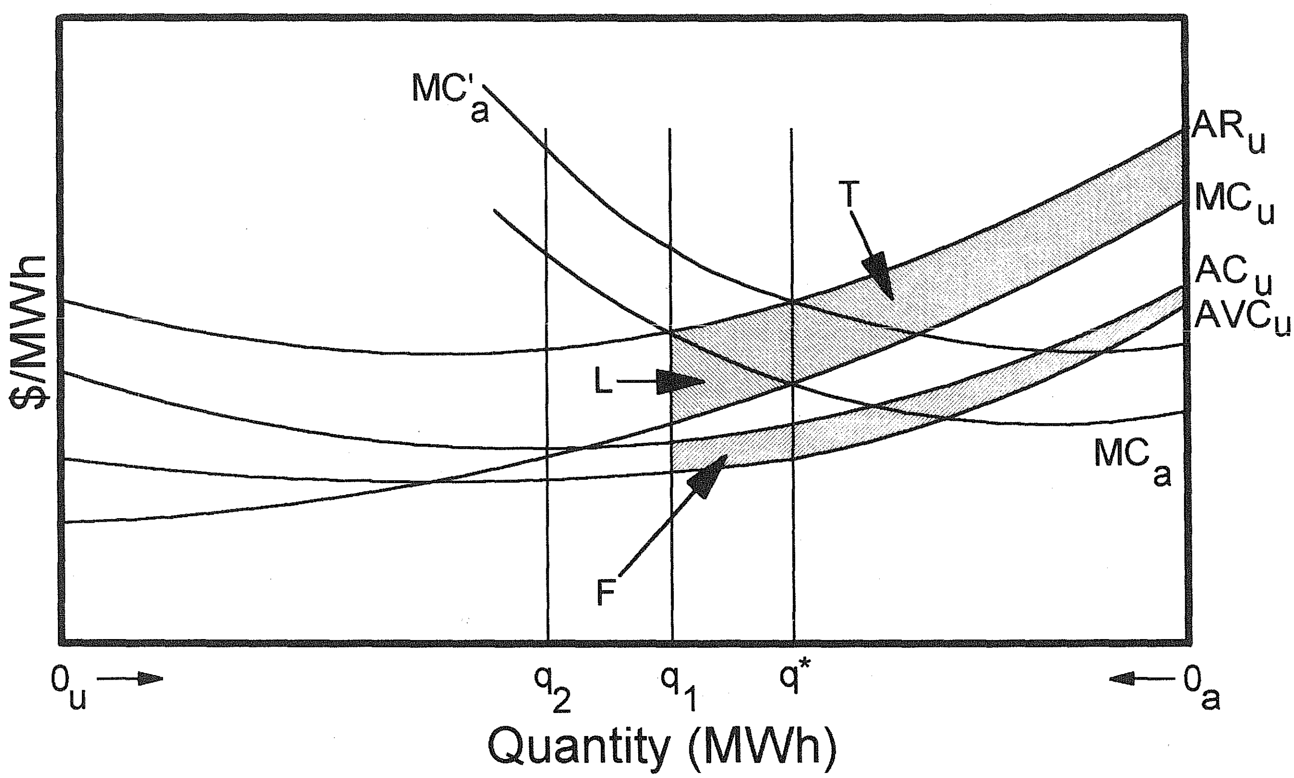

Figure 2.3. Effect of uneconomic bypass on the amount of transition costs.

lowest-cost generator, but may be used to allow the utility to recover its transmission and distribution costs.[10] For example, at the quantity q_2, bypass would not occur since the alternative supplier's unadjusted marginal cost (MC_a) is higher than the utility's rate (AR_u).

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[10] It is assumed here, for simplicity, that all the costs represented by the region T would be included in the access charge. However, there are costs that may not be passed through such a charge. A breakdown of these costs is discussed later in this chapter.

In Figure 2.4 at quantity q_3, there is too much utility power or *insufficient bypass*. Again, the higher cost to consumers is the triangular region L with the utility losses from bypass shown by T and F (not including area L). Note that both with and without the access charge at this quantity, as well as any quantity to the right of q^*, customers will choose the lower-cost alternative supplier. All quantities to the right of q^* represent insufficient bypass.

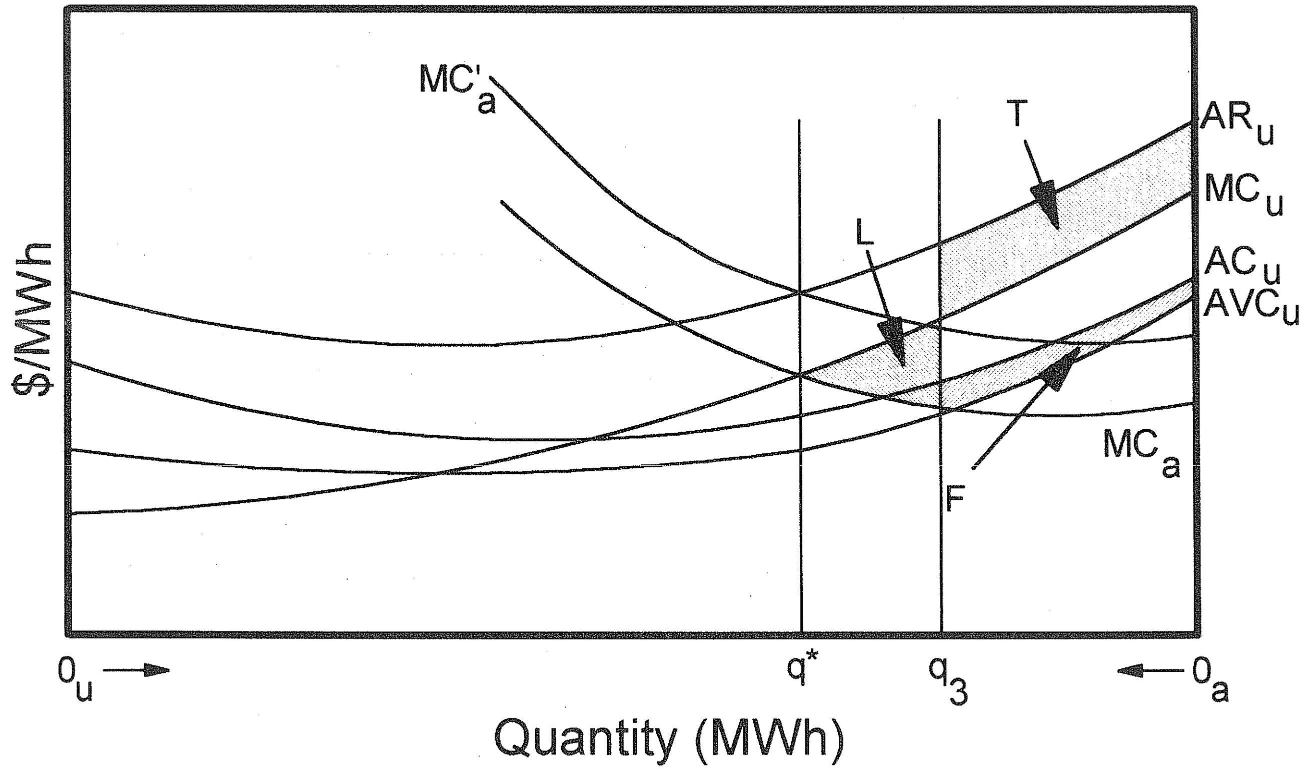

Figure 2.4. Effect of insufficient bypass.

Since the utility losses are smaller than they are at the optimal quantity, it may be tempting to find the quantity where the loss to consumers, L, is equal to the utility's losses, T+F. However, this would be misguided and ill-advised. First, in many, if not most cases, the utility will still be providing distribution, transmission, backup power, maintenance and other services to the exiting customer and, presumably, collecting a fee for these services. Therefore, not all of area T is a future "loss" to the utility. As noted above, any revenue from the sale of these other services should be subtracted from total transition costs. A "lost revenue" calculation of transition costs, based on the lost revenue requirement that was formerly contributed by a departing customer, should deduct the revenue from the sale of services provided by the utility to alternative suppliers and customers.[11] (As also noted above, the "avoided" generation costs should also be deducted from "lost revenue" calculations.)

Second, it is important to understand the origin of these potential transition costs. Some have identified the source of these costs as "stranded"[12] assets (expensive power plants and excess capacity) and liabilities (purchased power contracts with qualifying facilities), and regulatory assets (deferred expenses and DSM programs) and expenses from social or public policy programs (environmental, conservation, low-income programs).

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[11] In FERC's Final Rule (Order No. 888), lost revenues are calculated as the average annual revenue from the departing generation customer over three years prior to the customer's departure, less the average transmission-related revenues from the customer for the same period; minus a market value estimate based on either (at the customer's option): (1) the utility's estimate of the annual revenues from selling the released capacity and energy or (2) the average annual cost to the customer of replacement capacity and energy. This difference is then multiplied by the length of the "reasonable expectation period." Federal Energy Regulatory Commission, 18 CFR Parts 35 and 385, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," Order No. 888 — Final Rule, April 24, 1996, 592-3.

[12] Theresa Flaim, "Methods of Handling Transition Costs for the Electric Utility Industry," presentation to the National Association of Regulatory Utility Commissioners, Committee on Electricity, Washington, D.C., March 1, 1994; and Eric Hirst and Lester W. Baxter, "How Stranded Will Electric Utilities Be?" *Public Utilities Fortnightly* 133, no. 4 (February 15, 1995), 30-32.

However, not all these possible sources contribute equally to a utility's total transition cost. Focusing on what might be a relatively small percentage of the utility's overall rate (QF contracts for example), when generation costs are a much higher percentage of the overall rate, ignores the main potential source of cost reduction. The amount of the transition costs (and the probability of bypass) will generally depend more on the utility's generation cost and its overall rate level than other nongeneration costs. This means that the lower the utility's generation cost base, the more competitive they are and the less likely there will be opportunities for bypass and, therefore, the lower transition costs will be. Of course, the source and proportion of transition costs will vary by utility.

Figure 2.5 illustrates the effect of a decrease in the utility's marginal cost and average rate. The dashed curve MC'_u represents the lower marginal cost and the dashed curve AR'_u is the resulting new lower average-rate curve. The alternative supplier's marginal cost curve, MC_a, is the same. The new equilibrium quantity is now q^{**} (where $MC'_u = MC_a$). Thus, the utility, by decreasing its marginal cost, has increased the range where it is economically competitive from q^* to q^{**}. The indicated area G is the potential revenue gain to the utility from the lower cost and price for generation. Depending on the elasticities of the curves, the magnitude of the revenue gain may be much greater than the losses to the utility from bypass.

Given the assumption and likelihood that utility costs do not reflect the lowest possible costs because of cost-based regulation,[13] there is room for decreasing marginal cost and, consequently, reducing transition costs. A competitive wholesale and retail electricity market, with no compensation for transition costs, would induce this type of reduction.

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[13] There is an extensive literature related to the poor incentive given to utilities to minimize costs under cost-based regulation. See, for example, Jean-Jacques Laffont and Jean Tirole, *A Theory of Incentives in Procurement and Regulation* (Cambridge, MA: The MIT Press, 1993), Introduction and Chapter 1. As will be demonstrated, this is a critical feature of utility costs for determining transition cost recovery's affect on economic efficiency.

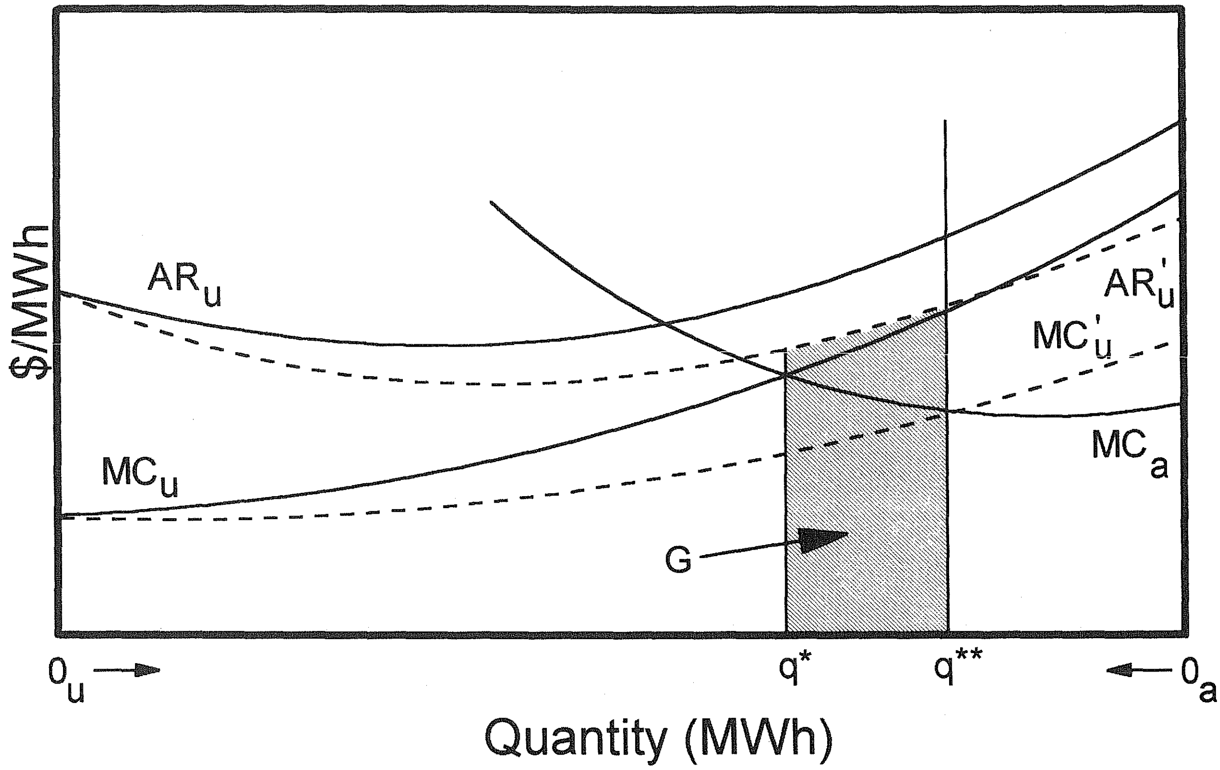

Figure 2.5. Effect of a change in utility marginal cost and average rate.

In summary, the preceding analysis allows several observations to be made about transition costs:

- the existence or amount of the transition costs depends on the relative positions of the utility and alternative supplier's cost curves and the utility's rate for a given quantity;

- transition costs occur when there is a competitive supplier (or suppliers) with marginal cost below the utility's rate for a relevant range of output with no access or exit fee, or below the utility's marginal cost with an access or exit fee;

- when the marginal cost of the alternative supplier is above the utility's rate, there are no transition costs and the utility remains the supplier;

- when the alternative supplier's marginal cost is lower than the utility's marginal cost, the transition costs, for a given quantity range, is the difference between the utility's rate and its marginal generation cost plus the portion of average generation costs that are average fixed costs;

- access charges or exit fees can be used to prevent uneconomic bypass, the case where the alternative supplier's marginal cost is between the utility's rate and marginal cost; and

- lowering the utility's marginal cost also results in a consummately lower rate, reducing the likelihood of economic bypass to competitive suppliers and, consequently, incurring transition costs.

These observations are important to consider when estimating the size of transition costs. For example, estimating transition costs as the difference between the utility's marginal cost and a competitor's marginal cost or the market price will inappropriately include some variable or avoidable costs and leave out costs above marginal cost but included in utility rates. Depending, of course, on the size of the actual transition costs, this method could understate or overstate the magnitude. Using only the difference between the utility's average rate and its marginal generation cost would miss bypassed capacity cost and possibly understate the amount.

A Further Examination of Utility Costs

From this analysis it becomes clear that there are two general categories of costs that cause a utility's rate to exceed a market or competitive price. These costs could place the utility in an uncompetitive position or at a disadvantage relative to market competitors. These general categories are:

- the amount that the utility's rate exceeds its marginal cost, and

- the amount that the utility's marginal generation cost exceeds the market price (or the marginal cost of alternative suppliers).

The first category is costs that do not contribute directly to the cost of generating electricity by the utility and are separable from the utility's marginal cost. They occur because embedded cost ratemaking includes costs that are not directly associated with electric generation. As noted, some of these costs may be recovered through an access charge for transmission and distribution service. These may be called infrastructure and program costs or nongeneration costs and include two types:

- costs that are or were sanctioned or imposed by the state or commission and are deemed necessary or desirable. In many cases, the largest[14] of this type of costs are the distribution and transmission costs. Others include the cost of conservation, low-income, or renewable energy programs or purchased energy contracts as part of a broader public policy strategy. These latter costs, however, may be only a small portion of the overall utility rate.

- A second type are costs that include excess capacity costs. These are costs that may fail a used-and-useful test or be disallowed and are most at risk of being "stranded."

The second general category, costs that contribute to the utility's marginal cost exceeding the market price, are simply direct generation costs. These include capital costs for bypassed capacity (as opposed to excess capacity), fuel costs, and operation and maintenance costs. This may be where considerable reductions can be made to lower rates and improve a utility's competitive position, in both the short and long run. Short-run cost improvements include reducing higher-than-market fuel costs and nonoptimal operation and maintenance costs. Longer-run improvements are mainly capital cost reductions and other costs that may not be minimized.

Figure 2.6 outlines a process that states could use to determine transition costs from the cost definitions discussed above. The objective is to separate the potential

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[14] These examples are provided as examples only and are not a description of all utilities' situations. Specific types will vary considerably by state and utility.

Market Price to Utility Rate Range	Potential Transition Costs	Supported or Avoided Costs
Utility Average Rate→		
System Costs	- excess capacity costs - obsolete infrastructure - nonsanctioned program costs	- infrastructure (T&D) - sanctioned program costs - approved excess or bypassed capacity costs
Utility Marginal Generation Cost →		

Generation Costs	- bypassed capacity	- avoided costs
		  - energy
		  - operating and maintenance

Market Price of Power→		

Figure 2.6. Separating potential above-market transition costs by source.

transition costs from costs that continue to provide infrastructure support, avoided costs that are no longer incurred, and program costs determined to have continued support. The shaded column on the left side of Figure 2.6 represents the utility's potential unrecovered costs (or revenue from rates) between the market price of power and the utility's rate. The figure then separates these costs into four general categories — potential transition costs that are either nongeneration (or system) or generation costs and supported or avoided costs, again separated by nongeneration and generation costs. Under traditional regulation, both categories of potential transition costs may be questioned on a used-and-useful or prudence standard. These issues would arise in the normal rate-making process. In a similar manner, states may review these costs to determine which will be recoverable (or continue to be recovered) and which will not.

A distinction is made here between excess capacity, which is not used to meet current load, and bypassed capacity. The latter was used-and-useful until bypass occurred. In this case, regulators would have to determine whether to continue cost recovery.[15]

The costs in the upper right hand corner of the figure, are those that may be sanctioned by regulators. The largest portion of these costs are related to infrastructure, in particular transmission and distribution. How to conduct this separation is now being debated and is not discussed here. Again, examples of program costs include conservation or low-income assistance programs that receive continued support from regulators. These would be the costs that would be appropriate to consider for inclusion in an exit fee.

[15] Under traditional rate-based/rate-of-return regulation, cost recovery includes depreciation expense, recovery *of* the capital cost, and a rate of return *on* the capital investment. Commissions may decide to allow continued return of the investment and no return on the investment, continue both, or neither (the remaining option, continuation of recovery on but not of, is unlikely). This will be discussed in detail in the next chapter.

How an Exit Fee Would Work

As discussed, if a competitor's marginal cost is between the utility's average rate and marginal cost, "uneconomic bypass" could occur. In this case, customers may choose the alternative supplier, but as noted above, it would be inefficient to allow the customer to leave the utility's system. Conversely, if the utility's marginal cost is above the alternative source's, then bypass would be economically efficient.

The following simple numeric example[16] shows how an exit fee can be used to prevent uneconomic bypass from occurring.[17]

Utility assumptions:

price = AR_u = 9¢/kWh

marginal cost = MC_u = 5¢/kWh

Alternative supplier assumptions:

price = P_a = marginal cost = MC_a = 7¢/kWh

In this case, bypass would be inefficient. To prevent "uneconomic" bypass, the regulator may set the price of the alternative source's power at

$$(AR_u - MC_u) + MC_a, \text{ or } 4¢ + 7¢ = 11¢$$

where $(AR_u - MC_u)$ is the exit fee. Since the utility's price is 9¢, no bypass occurs.

Conversely, if the alternative supplier's price and marginal cost were 4¢/kWh, then

[16] This example is based on a method presented in Joe D. Pace, Direct Testimony to the Michigan Public Service Commission, Case No. U-10143 and U-10176, March 1, 1993.

[17] Again this is in a strict economic sense ignoring, for the time being, programs to internalize externalities and other social programs.

$$(AR_u - MC_u) + MC_a,$$

would equal 4¢ + 4¢ = 8¢, bypass would now occur. Thus, bypass will only occur when the alternative supplier's marginal cost is below the utility's marginal cost.

This method of calculating an exit fee is based on a critically different assumption of average and marginal cost than those made in the above graphical analysis of this chapter. In the earlier graphical analysis, generation was separated from other costs of supplying power while the average revenue curve, or the average rate, included all costs. Exit fee proposals, in contrast, include all costs in both the marginal cost and rate, including costs for generation, transmission, distribution, and so on. Because of assumptions of economies-of-scale, average costs are declining in the relevant range of output. This means that average costs will be greater than marginal cost. It is further assumed that the utility's rate equals average cost.

This method of calculating the exit fee (that is, $AR_u - MC_u$)[18] makes it difficult to separate out transition costs. One result is that the utility is either fully compensated for all costs, or the costs are avoided since the remaining marginal costs not recovered are all avoided costs.

Most likely, the entire difference between the rate and marginal cost would not be used by a regulator. Costs that include infrastructure (distribution and transmission) would be included. Excess capacity costs, however, may not be included. If they are included, it would be only a portion.[19] Separating these costs can be accomplished in a similar manner to the above discussion.

With any method there will be a practical measurement problem. Marginal cost is not an easily identifiable number. It is complicated by the fact that utilities are currently cost-of-service regulated, meaning that there will be a divergence between

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[18] This method, based on utility marginal cost, should not be confused with FERC's "lost revenues" approach described in footnote 11.

[19] The application of the used-and-useful and prudent-investment tests to transition costs are discussed in the next chapter.

observed marginal cost and actual unobserved marginal cost (what a competitive firm would have).[20] The only way to find the true marginal cost, is to have a market develop. In this case, if there is competition, then the market price and marginal cost will converge.

This emphasizes the importance of the beginning assumptions when designing policies to deal with transition costs or attempting to calculate their magnitude. It is important to be clear on what costs are being included in the marginal cost calculations and utility rates.

Economic Efficiency

Economic efficiency has been used as an argument both to justify recovery of transition costs and to deny recovery. Those who argue for transition cost recovery cite two main negative efficiency effects: (1) it can cause an increase in the cost of capital, obviously an important consideration for electric utilities, and (2) there could be a market distortion from competition where the lowest cost, or most efficient power producer, is not always chosen (the situation of uneconomic bypass described above in Figure 2.3).

The first possible efficiency loss, from a cost-of-capital increase, is said to occur if transition cost recovery is denied, because investors will view an electric utility as riskier than before. As a result, they will demand a high return on their utility investments. This higher cost is usually passed through to ratepayers. Baumol and Sidak state that if utilities are not allowed to recover their costs, consumers would only win a "Pyrrhic" victory because "[t]heir short-run gains will be more than offset by the future deterioration in service."[21] FERC also raises this same basic concern, stating

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[20] A critical assumption of the above analysis is that the marginal cost curves represent the locus of costs that is the best possible practice for the firms.

[21] William J. Baumol and J. Gregory Sidak, *Transmission Pricing and Stranded Costs in the Electric Power Industry* (Washington, D.C.: The AEI Press, 1995), 106. Financial support for this publication was received from the Edison Electric Institute.

that "the prospect or lack thereof for recovering such costs from ratepayers could erode a utility's access to capital markets or significantly increase the utility's cost of capital."[22]

This argument, however, assumes the existence of several factors that are unlikely to occur for most utilities. First, it would only be an extreme case where the regulator did not allow cost recovery for capital and expenses to maintain and update the utilized part of the system. It is unlikely that regulators will deny cost recovery for services (such as transmission and distribution) provided to customers even when others are supplying the generation. Even when no fixed or sunk generation costs are allowed to be recovered, the utility will be allowed to recover the market price for generation it supplies *and* will be able to recoup its transmission and distribution and other system support costs. If this did result in a higher cost of capital it is likely to be small and last for only a limited time.

Where the effect on cost of capital is not small or temporary, it is likely to occur only in the case of utilities that are already in severe financial difficulty. While regulators may be reluctant to have a utility declare bankruptcy "on their watch," it should be remembered that when a utility does declare bankruptcy the lights do not automatically go off. The utility may remain in bankruptcy for a time and later emerge in better financial health, merge with another utility, or reorganize itself and sell or write off parts of the company. From an economic efficiency standpoint, society is *better off* after the financial readjustment since it results in a better allocation of resources overall. While there may be a temporary loss for current stockholders, after a period of adjustment, both consumers and the utility are better off; consumers have lower rates and the utility is in a more competitive condition.

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[22] Federal Energy Regulatory Commission, "Supplemental Notice of Proposed Rulemaking on Stranded Costs by Public Utilities and Transmitting Utilities," Docket No. RM94-7-001 (March 1995), 178. This is restated in the Commission's Order No. 888, in a conclusion section of the Final Order. FERC 18 CFR Parts 35 and 385, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," 453.

There is also the risk of a distortion in capital markets in the other direction. If uncompetitive utilities are "propped up" by regulators (such a strategy could only last a short time), investors will be sent the wrong signals on competitive risks and will not be able to determine the best use of their invested capital. The result would again be a misallocation of resources, in this case of capital.

It is likely that there may be some rise in the cost of capital in the move to competition since utility investments will be perceived to be a higher risk than under cost-based regulation. Electric utility financial instruments should be expected to approximate nonregulated firms over time. (Utility investor expectations and a means to determine them is discussed in detail in Chapter 4.) This does not mean that there is no net benefit from retail access and competition. The lower costs induced from market prices should offset the higher capital costs. If this were not the case, then by the same logic all industries should be regulated to get the lower cost of capital or less regulation should not be considered for regulated firms. Of course, a lower cost of capital was never intended to be the primary reason for regulation in the first place and the prospect of a slightly higher cost of capital should not be the primary reason to delay open or retail access today.

Measuring the *net* benefit of competition would involve the consideration of many more factors than cost of capital. Such a calculation would have to include, for example, an estimation of the loss of vertical economies and the gain from reduced generation costs.[23] A report prepared for Enron Capital & Trade Resources concludes that "permanent benefits to be gained from restructuring of the US electric supply industry vastly outstrip the transitional costs associated with the restructuring."[24] The authors of this report estimate the net benefit (to consumers and producers) of

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[23] For an estimate of vertical economies, see John E. Kwoka, Jr., "Vertical Integration and Its Alternatives for Achieving Cost Efficiency in Electric Power," unpublished manuscript, George Washington University (March 1996).

[24] Chitru Fernando et al., "Unbundling the US Electric Power Industry: A Blueprint for Change," report prepared for Enron Capital & Trade Resources, Houston, Texas (March 1995).

restructuring to be $80 to $100 billion *per year*. Moody's Investors Service[25] estimates "stranded" costs at $135 billion *total*.[26]

This leads to the second category of possible efficiency loss cited by those arguing for transition cost recovery, losses from uneconomic bypass. Baumol and Sidak[27] describe a method, which they call "Efficient Component Pricing," that is intended to prevent uneconomic bypass and describe it as "a necessary condition for economic efficiency, and hence for promoting the public interest."[28] This is in effect an access fee calculated in a similar manner to the exit fee example described above.[29] In this case, rather than exiting customers paying the fee, the alternative supplier pays for access to the utility's system. Since this cost is likely passed through to the customer, the incidence of the charge is the same.

The definition of what is economically efficient used by the supporters for transition cost recovery and the one used in this chapter so far is too narrow to analyze overall consumer welfare. Efficiency losses from the possibility of uneconomic bypass must be balanced against the negative efficiency effects of delaying the benefits of competition to ratepayers, of providing utilities with little incentive to manage and reduce their transition costs, and of limiting the number of alternative suppliers in the

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[25] *Stranded Costs Will Threaten Credit Quality of U.S. Electrics* (New York: Moody's Investors Service, August 1995).

[26] As noted in Chapter 1, even if both of these estimates are greater than the actual, the magnitude of the savings relative to the transition costs is likely to be considerable.

[27] Baumol and Sidak, *Transmission Pricing and Stranded Costs in the Electric Power Industry*, Chapter 9.

[28] Ibid., 121. A similar efficiency argument for transition cost recovery is made also by Paul L. Joskow, "Does Stranded Cost Recovery Distort Competition?" *The Electricity Journal* 9, no. 3 (April 1996).

[29] Baumol and Sidak's terminology is different than that used in the above analysis. Rather than an "exit fee" based on the difference between the utility's average revenue or rate and its marginal cost, they use the term "opportunity cost," the amount the utility forgoes when an amount of power is sold by an alternative supplier that used to be supplied by the utility. This is defined as the revenue given up less what the utility's "incremental" costs would have been had it supplied the power. The "efficient" price for transmission service (when the utility used to supply the generation) is then the opportunity cost plus the incremental cost to the utility to provide the transmission service to the alternative supplier. Similar to the result described above, this leads to the lowest-cost generation provider being the one to supply power to customers.

generation market. To consider these effects requires a much broader discussion of economic efficiency.

Static and Dynamic Efficiency

There are two general types of economic efficiency: productive or "static" efficiency and an overall or "dynamic" efficiency. Static efficiency is achieved when power is generated by the lowest-cost sources. Thus, static efficiency requires only economic bypass of the utility's system and no uneconomic bypass. Baumol and Sidak note also that to meet their condition of static efficiency requires that there are no monopoly profits or cost inefficiencies.[30] This assumes that the utility's and the alternative supplier's marginal costs are minimized and remain unchanged. Figures 2.1 through 2.4 above, while useful to describe the problem of transition costs, are a static analysis of the problem. In those examples, average rate and the utility's and competitor's marginal costs do not shift from their positions and are, by definition, assumed to be minimum costs. The curves only account for changes in quantity at different costs or changes in cost for different quantities. While this is useful for discussion and understanding the problem, it is not very realistic.

Because of regulation, utilities are likely to have cost inefficiencies.[31] This violates Baumol and Sidak's condition for productive or static efficiency. In addition, over time it should be expected that costs would change so the curves (rates and marginal cost) would be expected to shift. The effect of this shifting is demonstrated in Figure 2.5 above. This can be caused by changes in technology, fuel prices, or regulatory policy. Obviously, it is this last exogenous factor that commissions can affect the most. These shifts in the curves over time are caused by dynamic effects. When

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[30] Baumol and Sidak, *Transmission Pricing and Stranded Costs*, 117. The term "static efficiency" is not used, but the efficiency conditions described are consistent with the definition used here.

[31] See footnote 13. For an empirical analysis of utility costs and an example of utility cost inefficiency, see Gale A. Boyd and Marie R. Corio, "The Cost-Reliability Frontier: New Techniques for Evaluating Cost/Reliability Trade-Offs and Targeting Plant Spending and Performance," presented at 1994 International Joint Power Generation Conference, Phoenix, Arizona, October 1994.

developing a regulatory policy, therefore, it is important to also consider this second, and in many respects more important type of efficiency.

A key difference between static and dynamic efficiency is the element of time. Dynamic efficiency assumes that the utility's marginal cost can or does change over time or, more importantly, can be induced by policy to change. Competitive markets are by nature dynamic and it is these dynamic effects that are sought in the current electric industry restructuring efforts. Market competitors are driven to innovate and control costs to retain or attract customers (as long as it is, or is expected to be, profitable). Dynamic-efficient regulatory options provide more incentives for the utility to reduce its costs. Utilities can reduce costs by, for example, renegotiating fuel contracts, reducing operation and maintenance costs, or reducing the carrying cost of capital. Regulatory policy that can induce cost-minimizing behavior by utilities (and reduce the likelihood of future transition costs) include incentive ratemaking and wider use of competitive markets.

In theory, static efficiency requires that only economic bypass occurs. This is a necessary but not sufficient condition for dynamic efficiency, however. While there may be static efficiency, or no uneconomic bypass with production of a given output only from the lowest-cost suppliers, this does not mean that there is dynamic efficiency. Although, complete dynamic efficiency would require that static efficiency be achieved. In short, dynamic efficiency is the broader and overall efficiency condition to measure social welfare. Static efficiency would only indicate that production was from the lowest-cost producers at a given time.

In practice, these two definitions of economic efficiency are distinct in other ways. Although regulators may be able to determine if the lowest-cost producer is supplying the power, for example by comparing *known* costs, determining whether this is dynamically efficient would probably be impossible. Dynamic efficiency is found through the workings of the market where customers are choosing their supplier and producers are seeking every opportunity to reduce costs. For example, any action that limits the number of competitors may appear to ensure economic efficiency, but may remove competitive pressure on the utility to control costs. Also, regulators may impose access, entrance, or exit fees, in the interest of static efficiency, but could interfere with the market finding the dynamic-efficient solution. This is an inescapable (and perhaps paradoxical) outcome — attempts by the regulator to "correct" for static inefficiencies would only harm long-run overall efficiency.

Kahn separates the concepts of static and dynamic efficiency and examines a case where dynamic efficiency gains may outweigh static-efficiency losses. In a discussion of the merits of allowing a utility to charge marginal cost for a service, he points out that while it may be efficient "in the static sense" to allow the utility to drive out its rivals, there may be some "dynamic loss if the result is the elimination of those competitors."[32] He adds that preserving the competitors (by setting a price above marginal cost) would provide a "stimulus" to the utility's performance and "might in the long run contribute sufficiently to a greater and more varied innovation, to continual improvements in the industry's service and efficiency to outweigh the static-welfare loss involved in keeping it [the competitor] alive."[33] However, restricting competition in this way, he states, would require "a very heavy burden of proof." Of course, for electric utilities at this time, the debate on transition costs is not whether competitors should be supported, but whether the utility should be allowed to recover uneconomic costs. Because, allowing recovery would restrict the competitive outcome, the "heavy burden of proof" is on those who argue for recovery. Restricting the market's outcome (and its dynamic benefits) by supporting uncompetitive utilities (in the interest of static efficiency) only serves to delay the benefits of competition for consumers and hobbles potential competitors. The dynamic-efficiency gains from reduced costs, innovation, and lower prices to consumers, while difficult to predict, almost certainly outweigh any loss in static efficiency.[34]

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[32] Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions*, *Vol. I, Economic Principles* (Cambridge, MA: The MIT Press, 1988), 176. This discussion concerned AT&T's ability to, at its long-run marginal cost, drive out most or all rivals.

[33] Ibid., 176-77.

[34] As the analysis in Figure 2.3 above shows, "uneconomic" bypass will only occur in a limited range and the loss in efficiency will be small. The potential loss from "insufficient" bypass, on the other hand, could occur over a much wider range and be much larger.

Wenders attacks the entire notion of uneconomic efficiency and questions whether it actually exists. In his view, the notion of uneconomic bypass "misses the whole disequilibrium feature of the competitive *process*. Competition is a process by which economic efficiency, in a static-equilibrium sense, is brought about"[35] (emphasis in the original). Any "uneconomic" competition is "the most efficient means of bringing about the economic end" and "in the real world,. . .competition by allegedly inefficient providers happens all the time, and in fact in the long-run improves economic efficiency." [36] He adds that the "'cost' is not only noneconomic and sunk: It is a fiction created by the regulatory process to begin with — a regulatory process that has resulted in the massive distortions to economic efficiency."[37]

On the issue of regulators attempting to correct or prevent the loss from static inefficiency, he notes that it would "entrench the existing efficiency-distorting regulatory mechanism and deflect the corrective forces of competition."[38] Moreover, to suggest that the regulator "is suddenly going to come up with a costing methodology that solves the uneconomic bypass problem in the litigious atmosphere of a regulatory environment is naive."[39] These practical problems of "entrenchment" of inefficient regulatory costs and the measurement of the inefficiency are serious limitations that cast significant doubt on the practicality of attempting to prevent uneconomic bypass.

Recall that Baumol and Sidak note that their "efficient component pricing" rule requires that no production cost inefficiencies exist. In addition to (as noted above) this being currently highly unlikely for regulated utilities, the only way to actually ensure this is through the workings of a competitive market. This means that any attempt to put in place a mechanism to prevent uneconomic bypass when this condition is not met will

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[35] John T. Wenders, *The Economics of Telecommunications: Theory and Policy* (Cambridge, MA: Ballinger Publishing Company, 1987), 259.

[36] Ibid., 260.

[37] Ibid., 261.

[38] Ibid.

[39] Ibid., 262.

only impede the market's ability to reduce production costs to the minimum possible level. In effect, this becomes a self-defeating process, where the process itself prevents from being met the very condition that is required for its justification.

Over time, dynamic efficiency would lead to the utility's marginal cost being reduced to the market price. This market price would reflect a combination of the marginal costs of utilities, alternative suppliers, and so on. To be dynamically efficient, it is required that the market price of electricity be this marginal cost of all suppliers. This also has the effect of reducing the amount of transition costs over time. Figure 2.7 illustrates how increasing dynamic efficiency could, over time, reduce transition costs.[40] Average rate is again, as in Figures 2.1 through 2.5, depicted by the AR_u curve. Likewise, the MC_u and MC_a curves are the utility's and competitor's marginal cost curves for generating power at a given time. The difference is that time is on the horizontal axis rather than, as is usually the case when depicting marginal cost, quantity. In addition, it is assumed here that the commission has determined which costs are transition and which are infrastructure and supported costs. At the start, it is assumed that the rate includes some portion of (no judgment is made here of the proportion or which costs should be included) transition costs, shown by the shaded area. Over time, these costs are phased out. The proportion of infrastructure and program costs remains the same throughout this period.

In this example, the competitor's marginal cost is shown as increasing over time. This could occur (but is not required) for several reason. One is a rise in natural gas prices that may result from increased demand for natural gas as a fuel to produce electricity and for other uses (brought about by new technologies). Another possibility is that independent suppliers become increasingly subject to external costs through, for example, a broad-based emissions tax. In this figure, the utility's rate and marginal cost are decreasing. Ideally, the utility's marginal cost and its competitors' should either converge or merge into a market price. The utility's rate would, again ideally, equal its

[40] Figure 2.7 is similar to one presented by Matthew I. Kahal, *An Economic Perspective on Competition and the Electric Utility Industry* (Silver Springs, MD: Exeter Associates, Inc., November 1994). However, it is altered and used here to illustrate a different point.

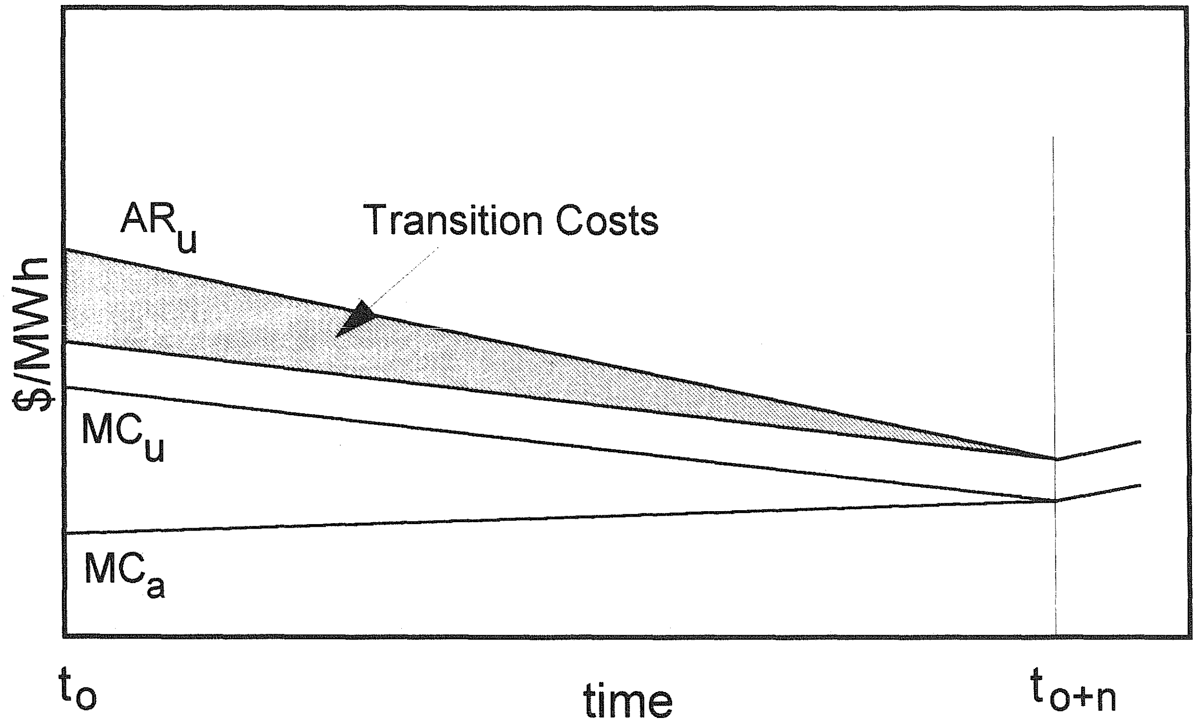

Figure 2.7. Effect of dynamic efficiency on transition and marginal costs and utility rates.

marginal cost.[41] The difference at t_{0+n} between the rate and the utility's marginal cost is the remaining nongeneration or infrastructure and program costs.

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[41] Recall that it is assumed here that the marginal generating cost is greater than average generating costs for both the utility and its competitors. Therefore, when price equals marginal cost, average costs are recovered. This means that capital service costs (for generation) are also recovered. This is based on empirical evidence from recent studies. See Thompson et al., *Economies of Scale and Vertical Integration*.

Transition costs are being reduced over time as, for example, assets are written down or depreciation rates are accelerated, the former for costs absorbed by the utility and the latter by ratepayers through the depreciation expense.[42] The transition costs shown in the shaded area are those assigned to ratepayers. Not shown in this graph is the portion taken by the utility. This could be represented by a fifth line above AR_u. The commission would determine the portion the utility and ratepayers should recover and, if any is to be recovered from ratepayers, how it should be recovered.

Time, t_{0+n}, is the point where the ratepayers' share of any transition costs would equal zero. It would not be necessary for commissions to know exactly when t_{0+n} occurs. This is because, as noted, competition will determine the level of the transitions, therefore determining them will be an on-going process. At some point in the future, however, transition costs will not be recovered at all.

Incentives to Mitigate Transition Costs

This leads to a policy question facing regulators today, what is the best way to mitigate transition costs? FERC asked these questions: "How should the Commission ensure that the utility takes all reasonable steps to mitigate its own costs so as to minimize what the customer would have paid? How should the Commission ensure that the utility does its best to sell the power at its highest possible value so as to mitigate the customer's stranded cost liability?"[43] If a commission states up front that it feels strongly that utilities should be allowed to recover all transition costs, it probably cannot practically ensure that all is being done to reduce stranded costs. The reason is that there is no realistic way for a commission to examine all available utility costs and

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[42] Specific methods of treating transition costs are discussed in Scott Hempling, Kenneth Rose, and Robert E. Burns, *The Regulatory Treatment of Embedded Costs Exceeding Market Prices: Transition to a Competitive Electric Generation Market* (Columbus, OH: The National Regulatory Research Institute, November 1994); and Lester W. Baxter, Stanton Hadley, and Eric Hirst, *Strategies to Address Transition Costs in the Electric Industry*, Draft Report (Oak Ridge, TN: Oak Ridge National Laboratory, April 1996), Chapter 2.

[43] FERC, Supplemental NOPR, "Stranded Costs by Public Utilities and Transmitting Utilities," 222-23.

options. A way that is consistent with dynamic efficiency and less costly administratively, would be to simply not allow, and certainly not to guarantee, full recovery of transition costs. This would provide a much more robust incentive to reduce stranded costs than any accounting or auditing means (this would also be more consistent with past regulatory treatments in other deregulated industries).

Robert Michaels notes that compensating utilities for transition costs could take the form of rent seeking where "[u]tilities will reasonably seek to maximize their collections, both by contriving high stranding estimates and by not engaging in reasonable mitigation."[44] Ideally, if transition costs are to be recoverable at all, they should be recovered only from the increased efficiencies realized by the utility through better use of the market to buy and sell power, by efficient use of its existing resources, and by renegotiating uneconomic contracts and obligations. This can be done by means of an offsetting account that allows the utility to write down an asset through cost reductions rather than immediately passing those savings to customers. States have used an offset of this type to deal with obsolete plant and equipment that is not fully depreciated. A mechanism using incentive regulation (price caps) is discussed in Chapter 5.

Conclusion

Although static efficiency may be an important consideration, it would be a mistake to focus exclusively on it when considering regulatory options. The condition of cost minimization required to make an access, entrance, or exit fee lead to an economically-efficient solution is unlikely to be met. Regulators, therefore, should consider dynamic efficiency as a primary goal of their transition policy. A major reason for moving to a more competitive market is to increase dynamic efficiency. Dynamic-efficient effects are potentially much larger than any static loss from uneconomic bypass. It was the dynamic-efficient effects in other deregulated industries that

[44] Robert J. Michaels, letter to the editor, *The Electricity Journal* 8, no. 2 (March 1995): 86.

reduced the transition costs and provided consumers with substantial benefits.[45] Preference should, therefore, be given to policy options that are consistent with the goal of dynamic efficiency and those at odds with it should be avoided. If a commission's intention is to facilitate the development of a dynamic competitive market, then dynamic efficiency should be its primary goal. This cannot be achieved by just focusing on static notions of economic efficiency.

Competition is not a zero sum game, where winnings equal the losses. Undoubtedly, there will be winners and losers. But in a positive sum game, such as competition in electric supply, the savings (winnings) to ratepayers, utilities that are able to compete, and their shareholders will likely exceed the losses from utilities unable to compete. The idling and writing-down of uneconomic assets increases overall economic efficiency.

There is no practical way to precisely identify in advance how much utility rates exceed marginal cost or market prices. Therefore, transition costs are not all determined at this time. Only a functioning and performing competitive market[46] can determine this over time. Since it usually will be impossible to determine in advance market prices and the level of competition that will occur, prospective determination of transition costs should be avoided, that is, letting the utility itself determine in advance what are its transition costs and then basing recovery on these estimates.

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[45] See Clifford Winston, "Economic Deregulation: Days of Reckoning for Microeconomists," *Journal of Economic Literature* 31, no. 3 (September 1993). The author concluded that society has gained at least $36 billion to $46 billion annually from deregulation.

[46] It need not be a textbook example of a "perfectly" competitive market to achieve significant savings over the current procedures.

CHAPTER 3

LEGAL OBLIGATIONS, THE REGULATORY COMPACT, AND BALANCING UTILITY AND RATEPAYER INTERESTS[*]

> *Nothing in regulation of utility-company earnings ever has received so much attention, historically, as the valuation of property. No other conflict in public utility regulation has been so spirited; none has consumed so much of the time of regulators, companies, and courts; and none has been so inconclusive.*
>
> *—Emery Troxel*[**]

The search for a regulatory policy on transition costs that is consistent with past regulatory treatment and does not violate the U.S. Constitution requires a thorough understanding of the history of what has become known as the "regulatory compact," and, in particular, of utility property valuation. As the above quote suggests, there is an abundant but inconclusive past to draw from. Examining past commission actions and state and federal court decisions does not provide a specific direction or a solution for states to consider when developing a transition cost policy. In short, they do not supply "the answer." They do, however, provide guidance on how transition costs should be treated and the constitutional limits of what states can do. Fortunately for state regulators, the inconclusiveness is indicative of the states' wide latitude, not from ambiguity in the law.

Balancing Policy Goals: Traditional Regulatory Objectives

The roots of the "regulatory compact" go back to the nineteenth century when the concept of public utility regulation was being developed from the common law

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[*] This chapter includes contributions from Robert E. Burns, Esq., Senior Research Specialist, The National Regulatory Research Institute.

[**] Emery Troxel, *Economics of Public Utilities* (New York: Rinehart & Company, Inc., 1947).

prohibition of unfair competition. This concept was applied to many industries and applied extensively to the railroad industry beginning in the mid-19th century. In 1912, Justice Oliver W. Holmes, in one of the earliest characterizations of a regulatory "bargain," described it as a balance between unregulated monopoly profits on the one hand with the unconstitutional confiscation of the utility's property on the other. He stated that "[n]either extreme can have been meant. A midway between them must be hit." He then stated:

> On the one side, if the franchise is taken to mean that the most profitable return that could be got, free from competition, is protected by the Fourteenth Amendment, then the power to regulate is null. On the other hand if the power to regulate withdraws the protection of the Amendment altogether, then the property is nought. This is not a matter of economic theory, but of fair interpretation of a *bargain*. Neither extreme can have been meant. A midway between them must be hit.[1] [emphasis added]

Justice Holmes stated that "a power to regulate rates has to steer between Scylla and Charybdis." In other words one cannot be completely avoided without increasing the risk from the other.[2]

Historically, first and foremost regulators and the courts have attempted to balance the interest of the utility with that of the public. Thus, in very broad terms regulation is intended to prevent monopoly abuses (such as "excessive" monopoly profits and price discrimination), determine "fair" or "just and reasonable" prices, and provide safe and reliable service while allowing the firm to earn a fair return on investments that is sufficient to continue operation (at a level necessary to maintain safe and reliable service) and attract capital for future investment. Concerns of economic efficiency, while often part of policy discussions and often considered, were clearly of secondary importance. The intention was to preserve the firm's financial integrity and allow a return comparable to investments of similar risk.

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[1] Cedar Rapids Gas Light Co. v. Cedar Rapids, 223 U.S. 655, 669 (1912).

[2] Many regulators may feel that this is a good characterization of the current dilemma they face with restructuring.

What Is the Regulatory Compact?

It is critical to first understand the regulatory compact and how it evolved to determine any possible customer obligations for transition costs. It was believed early in the electric industry's history that efficient competition was not feasible or practical. Thus, rather than allow redundant systems and parallel distribution lines, local municipalities and later state governments granted exclusive territorial rights to utilities. This was and is done through an agreement with state or local authority by franchise territorial exclusivity laws, a certificate of public convenience and necessity, or both.[3] Currently, each of the fifty states have laws setting up exclusive retail marketing areas for investor-owned utilities. At least twenty-three states provide specific service area assignments under territorial exclusivity statutes. These territorial exclusivity statues provide a utility with the exclusive right and obligation to serve in an identifiable service area. In at least thirty-eight states, service area assignments are made through the commission's granting of a certificate of public convenience and necessity. Because this sanctioned monopoly was the only supplier in the area (by design), the utility was required to serve all customers in their service area. The certification process normally is used to assign retail service areas.[4] Utilities have historically had an obligation to serve all retail customers requesting service and to make the investments necessary to provide this

"Special Privilege" of a Utility's Franchise

Justice Brandeis on the special nature of a utility's franchise:

. . .that a franchise to operate a public utility is not like the general right to engage in a lawful business, part of the liberty of the citizen; . . .that it is of the essence of a special privilege that the franchise may be granted or withheld at the pleasure of the State; that it may be granted to corporations only, thus excluding all individuals; and that the Federal Constitution imposes no limits upon the State's discretion in this respect.*

* Frost v. Corporation Com. of Oklahoma, 278 U.S. 515, 534 (1929).

[3] A fuller discussion is contained in Kenneth W. Costello, Robert E. Burns, and Youssef Hegazy, *Overview of Issues Relating to the Retail Wheeling of Electricity* (Columbus, OH: The National Regulatory Research Institute, May 1994), 51-54.

[4] In some states there are both territorial exclusivity statutes and certificates of public convenience and necessity.

service on demand. In order to meet this obligation to serve, utilities have made investments and entered into legal obligations, such as construction and purchased power contracts. The obligation to serve derives from the utility being granted an exclusive public utility franchise. The requirement to serve is in exchange for an exclusive but revocable right or privilege to serve an area.

In addition to the obligation to serve all who apply for service within their franchise or service area, public utilities have three other main responsibilities. First, utilities must provide safe and reliable service. Second, they may not engage in undue price discrimination. The prohibition against undue price discrimination requires that all similarly situated customers receiving identical service must be served on the same terms and conditions and for the same price. And third, the utility can charge only just and reasonable rates and may not earn monopoly profits with rates determined by a commission. What constitutes "just and reasonable" rates is determined by the regulator with the decisions by the regulator subject to possible judicial review. All of these requirements are designed for the expressed purpose of limiting the potential for monopoly abuse.

In light of the emerging competition, there is no doubt that the status of the regulatory compact will change. Table 3.1 describes the regulatory compact's relation to different levels of competition. In a transition period the utility will be granted a more limited franchise, have fewer requirements to serve, and less limits on profits. In competitive markets there are no obligations to serve or limits on profits.

It is this granting of a certificate to serve, along with the accompanying obligations to serve and other legal interpretations and evolving reinterpretations that are embodied in state and local statutes and case law that constitutes what has become known as the regulatory compact.[5] The regulatory compact does not and never has existed in a written form; rather it was formed through a series of court cases and commission actions. The regulatory compact is not necessarily a voluntary

[5] These utility obligations are discussed in Charles F. Phillips, Jr., *The Regulation of Public Utilities* (Arlington, VA: Public Utilities Report, 1984), 106-07. A history of the term "regulatory compact" is provided in Douglas N. Jones, *A Perspective on Social Contract and Telecommunications Regulation* (Columbus, OH: The National Regulatory Research Institute, June 1987).

Table 3.1 The relation of obligation to serve to levels of competition.

	Level of Competition	Utility is Granted	Utility Requirement
Regulation	None	Exclusive franchise (or protection from competition)	- obligation to serve - limits on profits
Transition	Limited (e.g., wholesale, new capacity)	Franchise limited to distribution	- less obligation to serve (retail only) - fewer limits on profits
Competitive Market	Full	No exclusive franchise	- no obligation to serve - no limit on profits

Note: Some competition with government ownership, interfuel competition, fringe-area competition, and self-generation.

agreement accepted by utilities. It is, as Justice Holmes observed, a *balancing* of utility rights and responsibilities. It represents the exercise of sovereign state police power in a manner consistent with both the Commerce Clause of the U.S. Constitution and the Federal Power Act and as developed in state and federal court rulings. The specific terms of the regulatory "compact" have never been a static arrangement, but an evolving doctrine that is *re*balanced as times and circumstances change.

In return for undertaking these obligations, the utility is granted *an opportunity* to earn a reasonable return on its prudent investment and to recover its prudently-incurred expenses. It does not bestow on the utility a legal right to recover all incurred costs or a return on its investments. As will be seen in the review of important court cases below, the utility is guaranteed the opportunity to earn a reasonable return on its investment, but this does not mean a guarantee to always receive such a return. There simply is no absolute guarantee that a reasonable return will be earned or that reasonable costs will be recovered. For the return on the utility's investment to be reasonable, however, it must reflect the risks imposed by the compact on the utility. The compact grants a right to an opportunity to collect a reasonable price for the utility's services based on prudently-incurred expenses and a reasonable return on prudent investments.

While the utility has been obligated, due to it being granted monopoly status, to serve all customers, *there is no reciprocal obligation to buy* on the part of customers. Retail customers as a whole provide the utility with the opportunity to recover its prudently-incurred costs and to earn a reasonable return on its investment. Traditionally, *individual or groups* of retail customers have been permitted to exit from the exclusive utility franchise area so long as they do not buy electricity from an alternative supplier in the area served by the franchised utility. Customer exit can occur when an industrial customer moves out of the utility's franchise area or simply shuts down. Also, retail customers exit by becoming wholesale customers by means of municipalization or when they do not take power from the host retail utility and self-generate (including cogenerate). In many circumstances, the remaining retail customers have acted as guarantors of recovery for costs incurred to serve the departing customers. The departing customers, however, are never asked to pay their share of the utility's investment costs. The exception, of course, is when there is an explicit written agreement as may be the case with utility wholesale requirements customers (municipalities and electric cooperatives) or sometimes a large retail customer. Generally, the risk that a retail customer or customers will cease to purchase power from the utility is generally assumed by the utility. This is considered a market risk for which the utility is compensated.

The right to recovery of and return on investment must reflect the risks imposed by the compact on the utility. Some have argued that the traditional risks do not include the risk that a customer could shop for alternatives after the utility already had incurred obligatory costs to serve that customer.[6] The current issue is whether the compensated

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[6] In its Supplemental Notice of Proposed Rulemaking on Stranded Costs, FERC states "[w]e believe that utilities should be allowed to recover the costs incurred under the old regulatory regime according to the expectations of cost recovery established under that regime." See Federal Energy Regulatory Commission, "Supplemental Notice of Proposed Rulemaking on Stranded Costs by Public Utilities and Transmitting Utilities," Docket No. RM94-7-001 (March 1995), 139-40.

risks under the current (traditional) regulatory compact include the risk that a retail customer can shop for alternative power sources after the utility has already obligated itself by incurring costs to serve that departing customer. It can be argued that the short-term risk of customers leaving by "traditional" means (such as municipalization) has always been a risk for which the utility has been compensated. A different set of issues is raised if nontraditional means of exit become available, such as retail wheeling, perhaps meaning the probability of a customer leaving will be greater than originally assumed. This issue is discussed in detail in the next chapter.

Valuing Utility Assets: Major Case History

For nearly one hundred years, regulators, legislators, and the courts sought a way to solve the problem of how to value a public utility's assets. Before 1900, regulation was more often price-based and set by legislatures or by franchise bargaining by municipalities with companies than based on the value of the company's property. As a result, the issue of confiscation of utility property was not a major concern for legislators or the courts.[7] *In Munn v. Illinois*[8] the Supreme Court suggested that while private property cannot be taken away without due process, legislatures can change the law. If there are "abuses by legislatures," the solution was for "the people [to] resort to the polls, not to the courts." The noninvolvement of *Munn* was clearly set aside in 1898 by the *Smyth v. Ames* decision. In *Smyth* the Court laid out its idea as to how utility property should be valued:

> We hold. . .that the basis of all calculations as to the reasonableness of rates to be charged by a corporation. . .must be the *fair value* of the property being used by it for the convenience of the public. And, in order to ascertain that value, the original cost of construction, the amount expended in permanent improvements, the amount and market value of its bonds and stocks, the present as compared with the original cost of

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[7] It was, of course, a major concern of the regulated who often challenged regulation on the basis that it was an unconstitutional takings of their property.

[8] Munn v. Illinois, 94 U.S. 113, 134 (1877).

> construction, the probable earning capacity of the property under particular rates prescribed by statute, and the sum required to meet operating expenses, are all matters for consideration, and are to be given such weight as may be just and right in each case. We do not say that there may not be other matters to be regarded in estimating the value of the property. What the company is entitled to ask is a fair return upon the value of that which it employs for the public convenience. On the other hand, what the public is entitled to demand is that no more be exacted from it. . .than the services rendered. . .are reasonably worth. [emphasis added.][9]

This marked the beginning of the "fair value" doctrine. Whether it was intended or not, these words of the Court were used as a means to determine rate base for almost half a century. Subsequent cases clarified what was meant by fair value. What was upheld by the courts was that fair value was to be defined as either original cost, the amount actually paid for installing the plant and equipment, plus improvements; or reproduction costs, the cost of plant and equipment estimated at market price levels prevailing at the date of valuation.[10]

It is important to note that, for the railroad company at the time of *Smyth v. Ames*, the original cost was higher than reproduction costs because the investments were made during and just after the Civil War when costs were higher than in the 1890s. The state (represented by William Jennings Bryan) advocated the lower reproduction value.[11] The Supreme Court generally also favored reproduction-cost valuation around the turn of the century because of the difficulty in determining original cost (due to different accounting practices and possible fraud).[12] Later, during periods of inflation, positions changed where companies supported a reproduction-cost

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[9] Smyth v. Ames, 169 U.S. 466 (1898), as quoted in Troxel, *Economics of Public Utilities* (1984), 265.

[10] Phillips, *The Regulation of Public Utilities* (1984), 287.

[11] It is interesting to note that the term "fair value" was a term invented and used by late nineteenth century populists to increase the appeal of the replacement value concept. This was part of their political stance for government control of monopolies. This use of language is much like the term "stranded cost" as used by the industry today to convey a sense of responsibility for all the utility's assets irrespective of any actual ratepayer obligation.

[12] Phillips, *The Regulation of Public Utilities* (1984), 288.

standard while regulators and consumer representatives advocated original cost. However, the principle of reproduction cost remained firmly in place with a majority in the Supreme Court through the late 1920s.[13]

Because of "the inexact, variable, and sometimes inexplicable meaning of fair property value,"[14] value was extremely difficult to ascertain. The subjective nature of the calculations inevitably led to the various interested parties coming up with values that differed widely.

As will be discussed in more detail below, under a reproduction-cost standard property that had no market value or was deemed not "used and useful" was excluded from the rate-base calculation.

The first significant chink in the reproduction-cost armor was a separate concurring opinion given by Justice Brandeis (in concurrence with Justice Holmes) in *Missouri ex rel. Southwestern Bell Telephone Co. v. Missouri Public Service Commission* in 1923. Justice Brandeis laid out what he thought was wrong with *Smyth* and what would be a better method for valuation:

"Changing the Rules of the Game"

State and federal commissions have in the past changed the manner in which they regulate utilities. Past examples of changes that sometimes adversely affected utility returns on their investments include, changing from reproduction-cost rate-base valuation to original cost, disallowance of intangible assets in rate base (such as good will or franchise value), and more recently, allowing competition in telecommunications services and natural gas supply companies.

On the flexibility of states to change Justice Brandeis, in a famous dissent, stated:

> Denial of the right to experiment may be fraught with serious consequences to the Nation. It is one of the happy incidents of the federal system that a single courageous State may, if its citizens choose, serve as a laboratory; and try novel social and economic experiments without risk to the rest of the country. This Court has the power to prevent an experiment [that]. . .is arbitrary, capricious, or unreasonable. . .because [of] the due process clause.*

Thus a state is free to regulate, not regulate, or change how it regulates so long as it does not violate the U.S. Constitution.

* New State Ice Co. v. Liebmann, 285 U.S. 262, 301 (1932).

> The so-called rule of Smyth v Ames is, in my opinion, legally and economically unsound. The thing devoted by the investor to the public

[13] Ibid., 289.

[14] Troxel, *Economics of Public Utilities*, 262.

> use is not specific property, tangible and intangible, but capital embarked in the enterprise. Upon the capital so invested the federal Constitution *guarantees to the utility the opportunity* to earn a fair return.[2] Thus, it sets the limit to the power of the state to regulate rates. The Constitution *does not guarantee* to the utility the opportunity to earn a return on the *value of all items of property* used by the utility, or of any of them. [emphasis added.][15]
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>
> [2] Except that rates may, in no event, be prohibitive, exorbitant, or unduly burdensome to the public. [Citations omitted.]

Partly because of, as Justice Brandeis put it, "the laborious and baffling task of finding the present value of the utility" the Supreme Court eventually cut the Gordian knot in *Federal Power Commission v. Hope Natural Gas Co.* This 1944 case de-emphasized the importance of finding a rate-base value and valuing methodology and placed more emphasis on the "end result" of a commission's decision. The Court stated:

> The fixing of prices, like other applications of the police power, may reduce the value of the property which is being regulated. But the fact that the value is reduced does not mean that the regulation is invalid. . ..
>
> [W]hen the commission's order is challenged in the courts, the question is whether that order 'viewed in its entirety' meets the requirements of the [Natural Gas] Act. Under the statutory standard of 'just and reasonable' it is the result reached, not the method employed, which is controlling. (Cases cited.)
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> *It is not theory but the impact of the rate order which counts.* If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important. Moreover, the commission's order does not become suspect by reason of the fact that it is challenged. It is the product of expert judgment which carries a presumption of validity. And he who would upset the rate order under the act carries the heavy burden of making a convincing showing

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[15] Missouri ex rel. Southwestern Bell Telephone Co. v. Missouri Public Service Commission, 262 U.S. 276 (1923) reprinted in Francis X. Welch, *Cases and Text on Public Utility Regulation* (Washington, D.C.: Public Utilities Reports, Inc., 1968).

> that it is invalid because it is unjust and unreasonable in its consequences. (Cases cited.) [emphasis added.][16]

The focus, in other words, should be on the "end result," not on the specific property of the utility or a rate-base valuation formula. This allowed states the discretion to also use an original-cost standard based on "prudent investment" — that is, original cost minus fraudulent, unwise, or extravagant expenditures.[17] *Hope*, however, changed the emphasis from rate-base valuation methodology to return on investment.

Application of the Prudent Investment Test

The prudence test establishes that costs that were reasonable at the time they were incurred, given the circumstances and what was known or knowable at the time, are to be included in rates. This provides the utility with *an opportunity* to recover these costs. Capital costs are recoverable with both a return of and a reasonable return on equity. Reasonably incurred operating costs during the test year are also included in the revenue requirement.

Is a Failure to Mitigate Now <u>per se</u> Imprudent?

There is a rebuttable presumption that costs reflected in current rates were reasonable when they were incurred. In the case of applying the prudence test to transition costs, however, there may be an issue as to whether costs that were prudent at the time they were first incurred *continue to be* prudent; particularly when continuing to incur those costs contributes to the utility's embedded-cost rates being higher than the market price of power. This may be less of an issue when the prudently-incurred costs in question are sunk and fixed (such as those of a power plant); however, whether prudently-incurred contract costs (such as fuel or power purchase contracts) continue to be prudent on a going forward basis may become an important issue.

Indeed, depending on the present value of buying out the contract, it may be *imprudent to fail* to renegotiate above-market price contracts to lower the utility's embedded-cost rates to more competitive levels. Where costs are sunk and fixed, there may be opportunities to lower the embedded-cost rates to a level closer to market price by mitigating those costs either by spinning off assets and placing them in the wholesale market, by selling off assets at their market value, or by writing down uneconomic costs. *One could contend that a failure to take appropriate action to mitigate transition costs would be imprudent. A utility should be expected to take action that lowers its embedded cost toward the market price.*

<u>Duquesne Light Co. et al. v. Barasch et al.</u>

Because *Duquesne Light Co. et al. v. Barasch et al.* is a relatively recent case and because it may have considerable bearing on the question of transition costs, it is reviewed here in detail. This is the most recent Supreme Court decision involving utility property

[16] Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944), from reprint of case in Welch, *Cases and Text on Public Utility Regulation*, 300-301.

[17] Phillips, *The Regulation of Public Utilities* (1984), 292

valuation.[18] Interestingly, the regulatory history of the last 100 years of the different utility investment valuing methods are reflected in this case. In particular, the Court discussed the different valuing methods used since *Smyth*, how it viewed the way assets should be valued, and the valuations method's relation to competitive markets. In short, the Court reaffirmed the *Hope* doctrine in this case involving recovery of costs from discontinued nuclear power plants. Agreeing with the Supreme Court of Pennsylvania when it held that a state law did not result in a takings of utility property, the U.S. Court stated:

> [w]e agree with that conclusion, and hold that a state scheme of utility regulation does not 'take' property simply because it disallows recovery of capital investments that are not 'used and useful in service to the public.'

How the Court arrived at this conclusion is outlined below.

The Pennsylvania Public Utility Commission (PUC) issued a final order in January 1983 that allowed Duquesne to amortize over a ten year period the costs of the discontinued nuclear power plants. However, just prior to that decision, in late 1982, a state law was enacted that stated that construction or expansion costs "shall not be made a part of the rate base nor otherwise include in the rates charged by the electric utility until such time as the facility is used and useful in service to the public."[19] Upon a request for reconsideration in light of the state law, the PUC reaffirmed its original rate order concluding that excluding the costs of the canceled plants from rate base but allowing recovery of the costs through amortization was consistent with the state law. The Consumer Advocate appealed this decision (and another similar decision involving Penn Power) to the Commonwealth Court, which upheld the Commission decision.

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[18] Another case (not discussed here), AGD v. Federal Energy Regulatory Commission, 824 F.2d 981 (D.C. Cir. 1987), dealt with the take-or-pay obligations of natural gas pipelines in "uneconomic" pipeline-producer contracts. FERC used this case to draw an analogy between its experience in the natural gas industry and its open access rule (both in the Supplemental NOPR and Final Rule 888). That this may be a misapplication of the AGD case is discussed in Kenneth Rose, Mohammad Harunuzzaman, and Robert E. Burns, "Comments on the FERC's Supplemental NOPR on Stranded Costs by Public Utilities and Transmitting Utilities," filed comments with FERC, reprinted in *NRRI Quarterly Bulletin* 16, no. 4 (Winter 1995), 481-93.

[19] 66 Pa. Cons. Stat. 1315 (Supp. 1988) as cited in Duquesne Light Co. et al. v. Barasch et al., 488 U.S. 299, 303 (1989).

This was then appealed to the Supreme Court of Pennsylvania where the Commission's decision was reversed.[20] The Supreme Court of Pennsylvania held that the state law prohibited both recovery of the costs through amortization *and* their inclusion in the rate base. The Court also rejected the claim of a constitutional challenge since the investment was not serving the public. Duquesne and Penn Power appealed to the U.S. Supreme Court arguing that the state law excluded their prudently-incurred costs, violating the U.S. Constitution's Takings Clause of the Fifth Amendment and its application to the states under the Fourteenth Amendment.

In the Supreme Court's opinion, delivered by Chief Justice Rehnquist, earlier court cases were cited and observed noting that "[i]f the rate does not afford sufficient compensation, the State has taken the use of utility property without paying just compensation." They then cited *Smyth v. Ames*, pointing out that "[h]ow such compensation may be ascertained, and what are the necessary elements in such an inquiry, will always be an embarrassing question."[21] *Permian Basin Area Rate Cases*[22] were also cited observing that "neither law nor economics has yet devised generally accepted standards for the evaluation of rate-making orders." In summarizing the *Smyth v. Ames* "fair value" rule, the Court noted that

> [i]n theory the Smyth v. Ames fair value standard mimics the operation of the competitive market. To the extent utilities' investments in plants are good ones (because their benefits exceed their costs) they are rewarded with an opportunity to earn an 'above-cost' return, that is, a fair return on the current 'market value' of the plant. To the extent utilities' investments turn out to be bad ones (such as plants that are canceled and so never used and useful to the public), the utilities suffer because the investments have no fair value and so justify no return.[23]

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[20] Barasch v. Pennsylvania PUC, 516 Pa. 142, 532 A. 2d 325 (1987) as cited in Duquesne, 488 U.S. at 305.

[21] Smyth v. Ames, 169 U.S. 466, 546 (1898), cited in Duquesne, 488 U.S. at 307.

[22] Permian Basin Area Rate Cases, 390 U.S. 747, 790 (1968), cited in Duquesne, 488 U.S. at 308.

[23] Duquesne, 488 U.S. at 308.

The Court then noted that while this rule gave utilities a "strong incentive to manage their affairs" it "suffered from practical difficulties which ultimately led to its abandonment." They then cited the Brandeis opinion in *Southwestern Bell* (cited previously) and noted how that signaled the beginning of the prudent-investment/ historical-cost rule. The Court, contrasting the fair-value rule with the prudent-investment rule,[24] stated that

> [u]nder the prudent investment rule, the utility is compensated for all prudent investments at their actual cost when made (their 'historical' cost), irrespective of whether individual investments are deemed necessary or beneficial in hindsight. The utilities incur fewer risks, but are limited to a standard rate of return on the actual amount of money reasonably invested.[6]
>
> [6] The system avoids the difficult valuation problems encountered under the Smyth v. Ames test because it relies on the actual historical cost of investments as the basis for setting the rate. The amount of a utility's actual outlays for assets in the public service is more easily ascertained by a rate-making body because less judgment is required than in valuing an asset.

They then cite the *Hope* decision (see above) as holding that fair value "is not the only constitutionally acceptable method of fixing utility rates" and "that historical cost was a valid basis on which to calculate utility compensation." They state then that "we reaffirm these teachings of *Hope Natural Gas*" adding

> whether a particular rate is 'unjust' or 'unreasonable' will depend to some extent on *what is a fair rate of return given the risks* under a particular ratesetting system, and on the amount of capital upon which the investors are entitled to earn that return. At the margins, these questions have constitutional overtones.[25] [Emphasis added.]

The Court outlined what they thought were the risks to utilities from different valuing methods.

[24] Duquesne, 488 U.S. at 309.

[25] Duquesne, 488 U.S. at 310.

> The loss to utilities from prudent but ultimately unsuccessful investments under such a system [Pennsylvania's use of a combination of the fair value and prudent investment rules[26]] is greater than under a pure prudent investment rule, but less than under a fair value approach. Pennsylvania's modification slightly increases the overall risk of investments in utilities over the pure prudent investment rule.
>
> Presumably the PUC adjusts the risk premium element of the rate of return on equity accordingly.[27]

The Court, however, showed little interest in being the arbitrator for balancing the interests of ratepayers and utility investors and getting involved in the intricacies of ratemaking.

> [A]n otherwise reasonable rate is not subject to constitutional attack by questioning the theoretical consistency of the method that produced it. 'It is not theory, but the impact of the rate order which counts.' Hope, 320 U.S., at 602. The economic judgments required in rate proceedings are often hopelessly complex and do not admit of a single correct result. The Constitution is not designed to arbitrate these economic niceties. Errors to the detriment of one party may well be canceled out by countervailing errors or allowances in another part of the rate proceeding. The Constitution protects the utility from the net effect of the rate order on its property. Inconsistencies in one aspect of the methodology have no constitutional effect on the utility's property if they are compensated by countervailing factors in some other aspect.[28]

Nor did the change from a pure prudent-investment test to a combined methodology raise constitutional questions

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[26] Where the Commission allowed amortization of the capital on such investments but the utility is not allowed to earn a return on that investment.

[27] Duquesne, 488 U.S. at 312.

[28] Duquesne, 488 U.S. at 314.

> a State's decision to arbitrarily switch back and forth between methodologies in a way which required investors to bear the risk of bad investments at some times while denying them the benefits of good investments at others would raise serious constitutional questions. But the instant case does not present this question. At all relevant times, Pennsylvania's rate system has been predominantly but not entirely based on historical cost and it has not been shown that the rate orders as modified by [the state law] fail to give a reasonable rate of return on equity given the risks under such a regime.[29]

As to whether a single theory or standard should be used as a constitutional standard, the Court stated

> The designation of a single theory of ratemaking as a constitutional requirement would unnecessarily foreclose alternatives which could benefit both consumers and investors.[10] The Constitution within broad limits leaves the States free to decide what ratesetting methodology best meets their needs in balancing the interests of the utility and the public.[30]

Application of the Used and Useful Test

A power plant that is no longer used and useful to the public because it is either technologically or economically obsolete can be excluded from rate base. If a regulatory commission were to order the plant out of rate base because it was no longer used and useful, this probably would result in a financial writedown because it would no longer be probable that there would be complete cost recovery of the plant. However, this would immediately raise the question of which plant represented the excess capacity and what was the cost of that plant. Because the underlying problem of technological or economic obsolescence is system-wide costs being above market prices, the used-and-useful test may not be appropriate. Alternatively, a percentage of system average generation cost might be excluded from rate base. But such an application of the used-and-useful test to average system asset costs may also strain how the test has been traditionally applied.

Alternatively, a state commission could require a utility to spin off excess generation capacity out of its retail rate base and allow the utility to sell as an Exempt Wholesale Generator (EWG) under EPAct. For such a rate-base spinoff to occur, the state commission would need to make a specific determination that allowing the plant to become an EWG would benefit its consumers, is in the public interest, and does not violate state law. The first part of this test could be met if the rate-base spinoff did not simply result in an above-market affiliated transaction. Instead, the rate-base spinoff should lower the rate base and cost of power to the retail customers. This approach could allow the utility to bring its embedded costs down to a level closer to the market price and mitigate its transition costs by selling otherwise uneconomical power at the wholesale market price.

[10] For example, rigid requirement of the prudent investment rule would foreclose hybrid systems. . . . It would also foreclose a return to some form of the fair value rule just as its practical problems may be diminishing. The emergent market for wholesale electric energy could provide a readily available objective basis for determining the value of utility assets.

[29] Duquesne, 488 U.S. at 314.

[30] Duquesne, 488 U.S. at 316.

While the bounds of *Hope* were not set by *Duquesne*, the Court has since denied *certiorari* in cases where the disallowed investments were many times larger than the *Duquesne* disallowance.[31]

The footnote in the last quote may be of particular interest and relevance when considering a transition cost treatment. The Court is clearly making a connection between fair-value/used-and-useful standard and competitive markets. In not wanting to "foreclose alternatives," the Court appears to be allowing states to choose the valuing method. This does not guarantee, of course, that a future court will allow a fair or replacement-value standard based on market value. But in states where the used-and-useful standard is applied, this suggests that it could also be applied to transition costs. Most states have used both the used-and-useful and prudence standards.[32] In adhering to the *Hope's* "end result," the Court has indicated that it will allow states to find their own means of balancing investor and ratepayer interests on future issues.

Is Not Allowing Transition Cost Recovery an Unconstitutional Takings?

It has been argued by some that utilities are guaranteed by legal and regulatory precedent to earn a return on all their prudent investments. For example, New England Electric System (NEES) argues that it is "well-established [that] state and federal principle guarantees utilities an opportunity to earn a fair return on investment made to serve the public. If restructuring denies that opportunity, the [state] will have to compensate [the utility] for the unconstitutional deprivation of this right."[33] This line of reasoning assumes that costs were undertaken by a utility to serve its customers and, once allowed in rates, must be recovered. These costs cannot later be denied recovery

[31] Richard J. Pierce, Jr. and Ernest Gellhorn, *Regulated Industries in a Nutshell* (St. Paul, MN: West Publishing Co., 1994), 124.

[32] Robert E. Burns et al., *The Prudent Investment Test in the 1980s* (Columbus, OH: The National Regulatory Research Institute, 1985).

[33] Massachusetts Electric Company (New England Electric System), "Legal Commentary: Entitlement to Stranded Cost Recovery," submitted to the Massachusetts Department of Public Utilities, Docket D.P.U. 96-25, February 16, 1996.

by the commission or its actions. Retail access, the argument goes, impairs or may prevent the utility's ability to recover all its prudent costs.

It is clear from case law discussed above and historic commission actions that utilities are entitled to recovery of their costs and a reasonable return on their investment, but not guaranteed to always receive a return. The phrase from the *Southwestern Bell* case that "the federal Constitution guarantees to the utility the *opportunity* to earn a fair return" (emphasis added) has never meant that under all circumstances the utility will receive a return. In *Bluefield Water Works & Improvement Co. v. West Virginia Public Service Commission*, decided in the same year as the *Southwestern Bell* case, the rights and obligations of the utility are articulated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, *under efficient and economical management*, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by change affecting opportunities for investment, the money market, and business conditions generally. [Emphasis added.][34]

These cases taken together, *Southwestern Bell*, which marked the beginning of the prudent-investment standard, and *Bluefield* make it clear that a utility, while entitled to earn a "fair" return, is obligated to act in the ratepayers' best interest. In the case of electric utilities this means supplying electric power that is safe, reliable, and at the lowest reasonable cost.

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[34] Bluefield Water Works & Improvement Co. v. West Virginia Public Service Commission, 262 U.S. 679, 692-695 (1923) from James C. Bonbright, *Principles of Public Utility Rates* (New York: Columbia University Press, 1961), 257.

Where it can be shown that the commission, legislature, or other governmental agency, through its authority required certain costs to be incurred, then the utility's claim for recovery may have some merit. An example may be the Public Utility Regulatory Policies Act of 1978 (PURPA) contracts. This legislation required a utility to interconnect with and purchase power from "qualifying facilities" (QFs). However, even here the right to recover these costs is subject to limitations. The specific terms of the contract between a QF and the utility are generally not governed by statute or commission procedures. Compensation for buying out a QF contract may be limited to the part of the agreement that was beyond the control of the utility, such as the commission-mandated standard-offer rate for power sold back to the utility; but not those parts that were not mandated by the commission and were utility controllable, such as fuel escalation clauses not based on an actual index of fuel prices or the failure to include termination terms in the contract. Also, as noted earlier, a utility may face a disallowance for a contract because of a failure to mitigate, such as through timely renegotiation of the terms or buyout.

Another example would be legislation or action by the environmental regulator that increased the environmental requirements of a functioning and economic plant or plants or prohibited power production from a particular type of plant altogether (for example, if the state declared that coal could no longer be used to generate power). Disallowing recovery of the additional costs imposed by the new requirement or the loss of the use of the plant that was beyond the control of the utility would be an unconstitutional confiscation of utility property. Commissions, typically, allow full recovery of environmental costs. However, again these costs are subject to review by the commission to ensure that any investment, operating costs, and management decisions are prudent. Any disallowance of these costs is not considered a "takings" if it is found that the utility did not exercise prudent judgment. Perfection is not the goal and states often grant utilities wide discretion. Rather, it is a means to hold the utility accountable for its decisions and act as a check on utility management's ability to simply pass mistakes through to ratepayers with no adverse consequences to itself.

When a state permits retail competition that could result in investment costs that are currently being recovered in rates from no longer being recovered, is the state, by the fact that these costs were being recovered in rates, obligated to continue to allow recovery? Clearly, as noted, if a state were to impair an asset or impose costs without compensation, this would be a takings. However, allowing retail access, for example, does not constitute a takings since the state is not taking or preventing the utility from earning a return. Commissions that choose retail competition are not removing a utility's ability or its opportunity to earn a return on its investment. Neither a state commission's action nor a competitive market actually causes "stranding" of costs to occur. The regulators (or customers) do not create stranded costs with competition; uncompetitive rates do.[35] These costs arise when a utility's price for power is higher than an alternative's price.[36] A utility is not being barred from competition — it can adjust its price and maintain its market share — it simply may not be able to charge the former tariff rate. While an opportunity may be guaranteed, the price was and is not guaranteed.

Indeed, it is the price of some utilities' power, relative to other sources, that is the primary reason for the calls for regulatory reform. Many utilities will greatly expand their customer base and sales by enticing customers away from other higher-priced utilities. These utilities will be clear winners in the move to competition. There is no corresponding discussion to limit the gains to utilities from competition.

The key thread that runs throughout the case history is that the utility is guaranteed an *opportunity* to earn a return on its investment. Since competition and its introduction does not cause "stranded" costs, and the utility is not likely to be prevented from an opportunity to sell its power, the introduction of competition does not result in an unconstitutional takings. As long as a state does not remove a utility's opportunity to earn on its investment, it is not an illegal confiscation of property. Moreover, the *Hope* "end result" test implies that commissions look at the *net* effect of competition on the utility, not just losses from uncompetitive assets.

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[35] Similarly, regulators could not create a competitive gain for a utility either.

[36] Of course nonprice factors, such as reliability, also enter into a customer's decision on who they want to supply them with power.

The Supreme Court on Assets that Lose their Value because of Competition

The Supreme Court has ruled on the question of whether it is a takings to not allow recovery of costs in other industries that were once regulated and then exposed to competition. The Supreme Court found twice that losses due to competition are not recoverable. These were cases involving industries that were regulated by state commissions in a similar manner to how electric utilities are regulated currently. The first of the two Supreme Court cases that addressed the issue of cost recovery and competition in public utility regulation is *Public Serv. Comm'n of Mont. v. Great Northern Utils. Co.* The Court stated:

> The due process clause of the Fourteenth Amendment safeguards against the taking of private property, or the compelling of its use, for the service of the public without just compensation. . .. But it *does not assure* to public utilities the right under all circumstances to have a return upon the value of the property so used. The use of, or the failure to obtain, patronage, *due to competition*, does not justify the imposition of charges that are exorbitant and unjust to the public. The clause of the Constitution here invoked *does not protect public utilities against such business hazards*. [Emphasis added.][37]

The type of competition that the Court is referring to is discussed in the next section. In *Market St. Ry. Co. v. California R.R. Comm'n* the Court reaffirmed that public utilities do not have a guarantee of recovery of costs that cannot be recouped due to "the operation of economic forces." The Court found that

> [i]t may be safely generalized that the due process clause never has been held by this Court to require a commission to fix rates on the present reproduction value. . .or on the historical valuation of property whose history and current financial statements showed the value no longer to exist. . .. The due process clause has been applied to prevent

[37] Public Serv. Comm'n of Mont. v. Great Northern Utils. Co., 289 U.S. 130, 135 (1933) from Charles F. Phillips, Jr., *The Regulation of Public Utilities* (Arlington, VA: Public Utilities Reports. Inc., 1993).

> governmental destruction of existing economic values. *It has not and cannot be applied to insure values or to restore values that have been lost by the operation of economic forces.* [Emphasis added.][38]

Public Serv. Comm'n of Mont. and *Market Street* do not say how assets that lose their value *should* be treated but that a decision by a commission based on the outcome of economic forces is not unconstitutional. It may be inferred that the Court has never intended for regulation to be a shield from competition. Regulation was a substitute for competition because it was believed, as noted above, that workable competition was not possible. If because of "the operation of economic forces" a utility is unable to recover its costs, this is the ideal test of the value of the utility's assets, that is, it is a better test of the used and usefulness and the continued prudence of the utility's costs. As discussed, this was the interpretation by the Court in the more recent Supreme Court case, *Duquesne*, and is consistent with *Public Serv. Comm'n of Mont.* and *Market Street.*

It has been argued that *Market Street* is not relevant to the situation faced by electric utilities.[39] The San Francisco street car company, and the street car industry in general, was so beset by competition from automobiles and other forms of transportation that it could not cover its costs no matter how much it raised prices since these substitutes were available. The question is: Was the Court saying that only in the case of an industry that cannot maintain its value that the effects of competition should be allowed to take hold and lead to its demise? Or is it a more general reference to the effects of competition on a regulated firm? While the Court did distinguish the case from typical regulatory cases where the firm has "earning opportunities," the Court was specifically making a general exception for competitive effects, not simply a special

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[38] Market St. Ry. Co. v. California R.R. Comm'n, 324 U.S. 548, 567 (1945) from Phillips, *The Regulation of Public Utilities* (1993).

[39] Massachusetts Electric Company, "Legal Commentary: Entitlement to Stranded Cost Recovery," 22-23.

provision for distressed industries.[40] Indeed, the only reason why the industry was distressed was because it could not compete with the new alternatives. The issue then for *Market Street* to apply is competition and its effects, not that there must be a sick industry. Moreover, even though the electric utility industry may not be a "sick industry," taken together, both *Public Serv. Comm'n of Mont.* and *Market Street* may in fact be very relevant to the electric utility case since, as with *Market Street*, the Court was ruling on a case where the very survival of the company was at stake. For electric utilities, only a handful of firms are in such a precarious state. If the Court would allow a company that was regulated to completely lose its investment, then a less drastic outcome is more likely, not less.

As in the last two Supreme Court cases cited above, while public utilities were and are regulated, the threat of competition has always been very real. In fact it has been used as a direct inducement for better cost control since the earliest days of regulation. Even though state commission action on retail access and FERC's open access will increase the *probability* that some utilities could lose customers (particularly if no action is taken by the utility to retain them), the *magnitude* of the effect (that is substantial) is the same; there is a difference in the kind of competition, but the magnitude is probably as significant as the type commissions dealt with in the past. As will be discussed in the next section, the notion that the effect of what the state and federal commissions are proposing is unprecedented and that electric utilities have never been subjected to such risks is simply not the case.

Competition in Other Forms and in Other Regulated Industries

Limited competition is not a new concept for regulated firms, regulators, the courts, or electric utilities. While electric utilities may receive an exclusive franchise,

[40] It does not matter if the competition occurred without government intervention or state and federal laws and policies were changed to clear the way for the market to work. In either case, the market determines the supplier. It is a fallacious argument to hold that a governmental agency "caused" the cost to the incumbent firm by allowing competition; the agency did not (and could not) create the alternative supplier. Otherwise, nearly every industry that has been deregulated could claim that some agency or Congress caused the losses they incurred. A market (like regulation but more effective) is a *process* that reveals uneconomic costs, not an *end* in itself that creates costs.

they historically have faced some competition from municipally-owned companies, rural electric cooperatives, and federal power authorities. Utilities have also had to compete with alternative fuels, such as natural gas, and from customer's own generation, such as cogeneration. Often competitive forces and technological change cause existing public utility investments to be in danger of not being recovered. Examples include manufactured gas utilities (supplying gas for lighting), canals (displaced by railroads), and, as just discussed, streetcars.

"Birchrod in the Cupboard"

"Governor Roosevelt's campaign speech on electric power at Portland, Oregon, in September, 1932, hinged on the policy of government competition as a regulatory alternative. His logic ran as follows: private operation was the norm and no community satisfied with the company would want government ownership, but every community should have the right, when dissatisfied, to undertake municipal ownership either as a bargaining weapon or as an actuality. This right was known as the 'birchrod in the cupboard.'"

From Richard Hellman, *Government Competition in the Electric Utility Industry: A Theoretical and Empirical Study*, Praeger Publishers, New York (1972).

Historically, when utilities faced this type of competition, what happened to a utility's original investment? As just discussed, the Supreme Court has ruled in the past that regulated firms are not protected from the losses they incur from competition. Below is a discussion of the treatment from state and federal commissions of competitive losses.

There seems to be little basis for the notion that all investments and expenditures by public utilities were always guaranteed full recovery. The following quote, from J.M. Bryant and R.R. Herrmann (1940),[41] addresses this type of competition and what is expected to happen to the regulated private company's investments.

> Competition of interurban railways with steam railroads, and of automobiles with both of these utilities, has caused many business failures in the railway field. Competition of electric lighting with gas lighting has driven the gas industry into other lines of service, such as heating and cooking. These forms of competition have a marked effect on

[41] Since the argument for transition cost recovery directly depends on appeals to past regulatory treatment when the investments were made, historical sources are cited on the issue of competition for evidence on how this was handled by public utility commissions and practitioners at the time. This deliberately removes it from current discussions of retail and wholesale competition.

> each of the competing enterprises and, when no new business of a different nature can be secured, result finally in receivership and bankruptcy.[42]

Bryant and Herrmann add later that private utilities compete with those owned and operated by municipalities:

> Competition exists with other forms of service such as that of the railroads with water and motor-truck transportation, of electrical utilities with gas utilities, and of private utilities with those owned and operated by municipalities and other branches of the government. In these latter cases, the utility must either meet the rates of its competitor or else lose the business and perhaps its investment.[43]

They also point out that a utility may have capacity that is not needed because of technological change or a change in public requirements. In these cases, as with competition,

> Sometimes a utility is built for supplying a larger territory or a larger load than later develops. At other times, a utility loses part of its business through competition or other causes, such as new inventions or changes in public requirements. Such a utility cannot expect the remaining customers to pay a full return on an overbuilt utility plant. All that can be expected is a sufficient return to pay operating expenses, return on the portion of the plant necessary to render the service, and perhaps to create a depreciation reserve to write off the excess investment.[44]

Creating a depreciation reserve means, of course, that the utility recovers the cost of the asset but the asset is removed from rate base so that no return is allowed.

The beneficial effect of competition in encouraging improved performance in regulated firms was clearly understood and was the intent in allowing competition. For example, Eli Winston Clemens (1950):

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[42] J.M. Bryant and R.R. Herrmann, *Elements of Utility Rate Determination* (New York: McGraw-Hill Book Company, Inc., 1940), 235.

[43] Ibid., 258.

[44] Ibid., 231.

> The threat of public ownership has continuously placed privately owned utilities on their mettle. . .. Local utilities — either publicly or privately owned — are monopolies and are wont to lapse into the managerial lethargy that so often characterizes monopoly. Only under the quickening spur of competition, actual or potential, from an alternative type of ownership will management be truly efficient.[45]

Again, far from a new concept, the idea of competition with public utilities has been considered for some time by public utility commissions.

> While many have been resigned to the notion of "natural monopoly," the sanctity of the concept has not gone unchallenged. In fact, during the past thirty years there have been at least 120 reported cases in which the desirability of competition in gas and electricity has been in issue before a state commission.[46]

Given the current debate, there may be nothing especially remarkable about the above quote; that is, until one considers that it was written in 1941 and the writer is referring to the period of 1911 to 1941. This is further evidence that the issue of competition versus monopoly is not new. State commissions, and earlier municipal governments, have been dealing with it since their creation.

Obsolete and Abandoned Plant and Equipment

In addition to the treatment of competition cited above, there are other issues that commissions have dealt with that are useful analogies for addressing transition costs. These include commission treatment of obsolete and abandoned plant and equipment. While these analogies may not be perfect and definitively determine how transition costs would be treated, they do provide some clues as to how a commission may want to address transition costs. The examples used here are drawn from historical commission actions and court cases. They are not provided to be descriptive

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[45] Eli Winston Clemens, *Economics and Public Utilities* (New York: Appleton-Century-Crofts, Inc., 1950), 579.

[46] Henry Kohn, Jr., "A Re-Examination of Competition in Gas and Electric Utilities," *The Yale Law Journal*, 50 (1941): 875-91.

of how to treat transition costs in the future, but rather as the basis for the analysis of ratepayer and utility responsibility. Again, examples from past actions are used for consistency with any past commitments that may have been made.

In the case of obsolete plant and equipment, the specific treatment varies by commission and the particular circumstances of the case. Phillips[47] summarizes commission treatment in four categories. First, any future obsolescence may be taken into account when establishing annual depreciation rates. For transition costs, since the original depreciation schedules were decided in the past when competition was not envisioned, this may mean a contemporaneous adjustment such as accelerated depreciation when it becomes apparent that a plant will be uncompetitive. This of course means that current ratepayers will be paying for the remaining plant through the operating expense of the utility's revenue requirement.

Second, obsolete plant could be considered standby capacity and simply left in rate base. In this case, customers would not only pay for the original cost of the investment but also a return on the utility's investment. Third, unrecovered depreciation on obsolete plant or equipment may be amortized. The costs would then be recovered over some relatively short period of time. And fourth, obsolete equipment may be written-off immediately by the utility. In this case the company's shareholders absorb the loss.

In the past, there was a definite desire to allocate the benefits of the new technology to ratepayers as well as limiting the recovery when the shareholders took the risk and were compensated for that risk. Phillips quotes a 1957 Minnesota Supreme Court decision:

> The principle of law which should guide the discretion of the commission in determining whether the customer or investor should be charged with the amount of alleged loss due to obsolescence is twofold: (1) the future customer may not be charged for obsolescence through any method of accounting unless the investor has suffered an actual loss by not having fully recovered prudently invested funds, and (2) even if such loss has occurred, it is unreasonable to charge the customer *if the investor has been compensated for assuming the risk of obsolescence*. . ..

[47] Phillips, *The Regulation of Public Utilities* (1993).

> Where an actual loss has occurred due to obsolescence, the commission may, in the exercise of its judgment, apportion one-half of all such actual loss to the investor and charge the remaining one-half to future customers by amortization as an operating expense over a period of years. [Emphasis added.][48]

Troxel also discusses the issue of treatment of obsolete plant and equipment and also found no consistent pattern. He observed that "[a] few commissions have expressed opinions on the amortization of obsolete plant investment. Some of them have approved amortization and others have disapproved it." He cites the Missouri Commission from 1939:

> Sudden changes. . .are hazards of the industry and result in a loss to the investor unless the change benefits the consumer by offering him the same service at a lower rate or a better service at the same rate, in which case the superseded property should be amortized out of the rates paid by the consumer.[49]

Troxel then goes on to cite a contrary finding of the Missouri Commission in another case that was supported by the Missouri Supreme Court that stated that ". . .when an appliance becomes obsolete by reason of scientific discoveries and inventions, it is a risk which investors in utilities must take. . . .."[50] In a case involving the substitution of busses for streetcars, the New York Commission found that amortization of the old investment ". . .ignores the right of the public to enjoy modern and satisfactory transportation. . .without penalty."[51]

Of course, there are several problems with this analogy to obsolete plant. First, the amount being dealt with is generally small relative to the firm's total size. The plant

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[48] Minneapolis Street Ry. Co. v. City of Minneapolis, 86 N.W. 2d 657, 659, 660 (1957) from Phillips, *The Regulation of Public Utilities* (1993), 276.

[49] Re Laclede G.L. (Mo.), 30 P.U.R. (N.S.) 13, 25 (1939) from Troxel, *Economics of Public Utilities*, 365.

[50] St. Louis v. P.S. Com. (Mo. Sup. Ct.), P.U.R. 1932A 305, 320 from Troxel, *Economics of Public Utilities*, 365.

[51] Re Rochester E. Ry. Co. (N.Y.), 36 P.U.R. (N.S.) 161, 170 (1940) from Troxel, *Economics of Public Utilities*, 365.

may have already been largely depreciated and may be nearing the end of its useful life. Second, the customers will likely benefit from the new technology now being used by the utility that was replacing the old plant or equipment. In the case of competition, the utility may be displaced by another firm. And third, the plant, in most cases was very old and was past its useful life or displaced by new technologies.[52] This, of course, is not the same as being displaced by competition.

In the case of abandoned plant, there is a similar wide variation of commission treatment. An NRRI study in 1985[53] found in examples of thirty-one state commissions, the District of Columbia, and FERC treatments of abandoned plants that seven states did not allow any recovery of costs at all; of the twenty-six commissions that did allow some recovery, twenty (including FERC) did not allow any return, four did allow a return (including the District of Columbia), and two states had cases where they did both. (Recall that in the *Duquesne* case the Pennsylvania Commission originally decided to amortize the cost of the abandoned nuclear power plants and not allow any return.) A common treatment was to amortize all or part of the cost over a period of time (up to twenty years) and deny a return on the unamortized balance. The amortized portion may reflect a partial disallowance in some cases based on the prudence of the decision and the action before the plant was canceled or abandoned. It is interesting to note that often even when no imprudence is found, shareholders were still, in some cases, be required to bear at least part of the cost of abandoned plant. In several cases of complete denial of cost recovery the primary reason given was that the plant was not used and useful, not because of imprudence.

While treatment varies by commission and also varies on a case-by-case basis, the outcome depends on the facts of the case, state statutes, and previous commission and court action. Also, commissions and the courts were looking at the original decision to begin the plant, costs incurred, risk incidence, and the timing of the

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[52] Of course, competition may be driven by a newer more efficient technology that could displace relatively recent plant additions. In this case the effect may be comparatively large.

[53] Burns et al., *The Prudent Investment Test in the 1980s*. Also see, Paul Rodgers and Charles D. Gray, "State Commission Treatment of Nuclear Plant Cancellation Costs," *Hofstra Law Review* 13, no. 3 (Spring 1985), 443-67.

canceled or abandoned plant. The NRRI report summarized the reasoning of one state commission that denied a utility's cost recovery of two nuclear power projects:

> [i]n reaching its conclusion that no recovery would be allowed because the plant was not used and useful, the Commission reasoned that the utility shareholders risk not only the possibility that they may not earn a return on their investment, but they risk their initial investment itself if the project does not become used and useful. To hold otherwise would allow a utility's shareholder to have an investment that was risk-free or subject to only a limited risk.[54]

Recasting the Regulatory Compact

In a historical context, the current debate on "stranded" cost is perhaps not that unusual. In many respects the debate mirrors the fair value-reproduction cost versus original cost-prudent investment debate of one hundred years ago. Many of the plants that have a book cost above market today were begun during the relatively high inflation period of the late 1970s and early 1980s. Because of a decline in inflation, technological advances, lower fuel prices (especially natural gas), and a lower cost of capital (interest rates), alternative suppliers (including utilities that did not invest heavily during that period) have relatively lower costs.

The fair-value standard was not sustainable because there was no clear market price to base it on and it required a great deal of judgment and supposition. However, as noted by the Supreme Court in *Duquesne*, market-based valuation is possible and more practical with competitive markets developing for wholesale and retail customers. In other words, market valuation or a reproduction-cost standard can now replace original cost valuation where the economic value of utility assets are based on the market, not regulation. Since *Hope*, commissions have used a combination of the property value approaches. This is not mere opportunism by commissions; that is, picking the approach that provides the lowest cost when it suits them. Rather, the approach was chosen for practical reasons when the difference between the two

[54] Ibid., 87, summarizing a 1983 Montana PSC decision.

valuation methods diverged and became readily apparent. We are again at such a moment in history.

The examination of the origins and content of the regulatory compact finds little basis for the claim that utilities are always entitled to cost recovery and a return on their investments. Indeed, a strong argument could be made that to be consistent with past treatment and the manner in which the compact has been interpreted by many states, a guarantee of full recovery of transition costs is what would be inconsistent. There is no "entitlement" to "stranded" cost expressed or implied by the regulatory compact. The only entitlement granted was the revocable privilege to serve an exclusive territory. The obligation to serve stems from this privilege. The compact is not an agreement to pay *all* costs (prudent or otherwise) because of the obligation to serve. It is much more complex than simply "I am obligated to serve, therefore customers are obligated to pay my costs."

A description of the regulatory compact as historically interpreted, may be as follows: the careful balance between compensatory rates and confiscation of utility property that allows a utility an *opportunity* to earn a reasonable return on their investment in exchange for providing safe and reliable power at reasonable cost to all customers who request service. This opportunity is held in check by the used-and-useful and prudent-investment tests, as well as from competition from government ownership, fuel substitutes, and self-generation. Another important feature of the compact is the continuous rebalancing that takes place to accommodate changing conditions in the industry. Clearly, some kind of rebalancing is needed again. Retail access broadens the scope of competition, but not the potential magnitude of its effect as compared with other forms of competition that the electric utility industry has historically faced. However, a means of recasting the compact that is consistent with past treatment of assets but does not unreasonably impair the development of competition needs to be found. In Chapter 5 an incentive mechanism is discussed that is intended to be consistent with these seemingly contradictory ideas.

As revealed in the discussion of court cases and commission decisions, the answer to treatment of lost utility value is not cut and dried. But a general path can be found that is consistent with these past treatments and, in particular, the finding of

Duquesne that equated risk to the utility and the method of valuation. If a state used or uses a "pure" prudent-investment test for valuing utility property, then the utility most likely received a lower return on its investment in rate cases. This is because the utility was subject to very low risk of loss of its investment and the rate of return should reflect that. For transition costs, the utility subject to a "pure" prudence test should expect to recover at least its costs and perhaps a return. Conversely, if the state used or uses a "pure" used-and-useful test, than the higher risk would be reflected in a higher rate of return. In this case the utility should expect no recovery of the investment costs or a return. The utility was already compensated for the risk that the investment's original cost may not be recovered, even if a market situation did not exist when the investment was made.

However, most states do not use a "pure" form of either valuation method; rather they use a combination of both. This is the primary reason why the treatment varies for the analogous situations across states and sometimes even within states. Both the used-and-useful tests and the prudent-investment tests are used by states as a way to curb the incentive to create excess rate-base padding or uneconomical management of costs. With respect to transition costs, states may consider the return given to the utility and allow total, partial, or no recovery of costs and allow either a return on the allowed portion or no return at all. Again, this is not an inconsistency or opportunism on the part of commissions; rather, it is very consistent with past treatment. This points out the importance of an analysis of the risk/return that the utility was subject to when determining transition cost treatment.

Utilities had to make choices on how they were going to serve their customers. Sometimes these turned out to be very good decisions and ratepayers and utility shareholders both benefited. However, sometimes the utility made decisions that, in retrospect, turned out to be poor choices. It is important to note that customers, or their representative, the commission, were usually not a party to those decisions. Since commissions simply do not have the same level of information and resources that the utility has access to, they often act as reviewers of plans and hear the arguments of interested parties. In these cases, it would be difficult to see why ratepayers should now shoulder the entire burden of a utility's loss from being uncompetitive. In recent years, however, many commissions adopted integrated resource planning (IRP) as a means to assert more control over the planning process of utilities. In addition to other factors, the IRP process was the direct result of previous bad investments made by utilities. In many cases, but not all, the IRP decisions involved demand-side management programs, not power plants. Often the commissions avoided actual approval of the particulars of the plan, approving the plan itself. In cases where specific investment decisions were approved, such as approval (or "preapproval") of a power plant or a sulfur dioxide scrubber that later turned out to be unwise, the commission may have to at least allow recovery of the capital cost. The investment's unamortized balance may, however, be removed from rate base.[55]

This balancing of the risk and reward or penalty can be termed "regulatory symmetry." Was the utility historically compensated through its rate of return for the risk that costs would be unrecovered due to market forces? Certainly, the current rate of return of a utility contemplates a certain degree of market risk. If a utility loses customers because of municipalization, self-generation, or economic downturns, the utility often bears the risk of a revenue shortfall at least until the next rate case. (Working in the other direction, regulatory lag provides the utility with an incentive to be more efficient and allows them to retain the benefit.)

It can be argued that because a utility can subsequently come in and request higher rates to spread its required revenue over a smaller base of customers, its rate of return only compensates it for shorter-term market risks. However, normal investment risks included the risk that demand would change, and there is no obligation for a commission to shelter a utility from market forces presented because customers have alternatives. In other words, the utility's rate of return already compensates it for the market risk that customers would find alternatives.

State commissions consider market risk due to the possibility of economic downturn and attrition of customers (including that due to fuel switching and the possibility of self-generation or cogeneration); it would not be unexpected for such state

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[55] Some argued that if preapproval and a guarantee of cost recovery is given, the utility should receive a very low rate of return. This would be consistent with the regulatory balance of risk and reward or penalty similar to a "pure" prudent-investment test.

commissions to also consider attrition due to municipalization and/or retail access. In such jurisdictions, it can be argued that the utility's rate of return on equity has already compensated the utility for the risk that costs will not be recoverable due to declining sales, whatever the cause. Again, the regulatory bargain only guarantees the utility an *opportunity* to earn a reasonable rate of return on its prudently-invested capital; it provides no guarantee that rate of return will actually be earned.

While the introduction of competition in retail electric markets may appear to have a negative effect on electric utilities; this presupposes that the utility either cannot or will not take steps to lower its costs and rates. Many, perhaps even most, utilities in fact will have opportunities to realize *higher* earnings under a regulatory regime with incentive- and market-based rates. The focus should not be on just the possible losses by utilities. This underscores the importance of having the risks be commensurate with the reward or penalty. For example, if a commission commits to guarantee full recovery of transition costs, while simultaneously allowing a utility to retain more of the benefits of being competitive, an incentive asymmetry is created. That is, if the utility is competitive it is rewarded, if it is not, it is made whole from a transition cost payment and is not penalized. Another way to have regulatory symmetry in the future (but not a recommended way) would be that none of the benefits from competition or incentive ratemaking should be allowed to the utility if it receives all of its transition costs. As noted, an incentive mechanism that is consistent with regulatory symmetry is presented in Chapter 5. In short, commissions should avoid, as one observer put it, "socializing the losses while privatizing the rewards."[56]

[56] Author's recollection of a comment made by Douglas N. Jones at the NRRI "Workshop on Implementing the Electric Utility Provisions of the Clean Air Act Amendments of 1990," Arlington, Virginia, January 1991.

CHAPTER 4

COMPETITIVE RISK, INVESTOR EXPECTATIONS, AND TRANSITION COSTS

The interest rate required on money invested in any enterprise bears a direct relation to what is called the 'risk of the enterprise.'. . .Among these risks [for public utility investments] are competition with other forms of supply such as establishment of a municipally owned plant competing with a privately owned utility; [and] competition with other sources of supply such as competition of one form of illuminant with another. . ..

J.M. Bryant and R.R. Herrmann[*]

That public utilities have faced competitive risks, as described in Chapter 3, is not a new concept. In addition to what may be called "traditional" sources of competition (municipal utilities, self-generation, other fuels, and so on), utilities were required to interconnect with and purchase power from two new sources of power generation[1] introduced in the Public Utility Regulatory Policies Act of 1978 (PURPA). In enacting PURPA, Congress's primary goal was *not* to create a competitive power market. Its primary goal was the conservation of energy resources and, to a lesser extent, national security (by encouraging a less centralized power production). However, PURPA did begin a series of events that has lead to the current discussions of open and retail access.

Initially, states implemented PURPA by setting "avoided cost" rates administratively, as required by FERC. Serious discussions of expanding competition

[*] J.M. Bryant and R.R. Herrmann, *Elements of Utility Rate Determination* (New York: McGraw-Hill Book Company, Inc., 1940), 227.

[1] These sources were cogenerators and small power producers. In order to become a "qualifying facility," the power source had to meet certain power, fuel, and ownership requirements (determined by FERC) to obtain the interconnection.

beyond PURPA's original purpose began in earnest in the early 1980s. Discussions were still, however, at a somewhat theoretical level. A discernable turning point occurred by the mid-1980s when some states began competitive bidding procedures (starting with Maine in 1985). In 1988 FERC issued three NOPRs, one of which dealt with competitive bidding for generation.[2] While this NOPR never became a rulemaking, FERC did partially implement its intent on a case-by-case basis. In addition, FERC began to use market-based ratemaking for some wholesale power contracts.

Additional pressure for regulatory reform came from the rapid fuel price increases and nuclear cost overruns and disallowances that began in the 1970s and continued into the 1980s. Simultaneously, state and federal regulators began to take action to deregulate natural gas, telecommunications, airlines, trucking, banking, and other industries. This was a further portent of the future intent and direction of the regulators. By the mid- to late-1980s it was obvious to most observers of the electric utility industry that some kind of change was inevitable and only a matter of time.[3]

Determining Utility Investor Compensation for Competitive Risk

When utilities and their investors became aware of the changes in the industry, and in particular, when they became aware of the increased risk from competition, is an important factor in determining when a commission should "start the clock" when calculating transition cost liability. If open and retail access expand customer options and make it more likely that customers will exercise their options, then it is reasonable to assume that investors would react appropriately and incorporate this increased risk. Capital markets would, therefore, demand a higher return for utility investments. The immediate effect would be a price drop for utility securities, something that has already

[2] Federal Energy Regulatory Commission, Notice of Proposed Rulemaking: Regulations Governing Independent Power Producers (RM88-4-000), Regulations Governing Bidding Programs (RM88-5-000), and Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities and Interconnecting Facilities (RM88-6-000), March 16, 1988.

[3] Of course, some still resist and oppose the idea of open and retail access.

been observed.[4] Regulators, when determining the allowed rate of return, take cost of capital into consideration. The risk of customer departure would, therefore, in time, be reflected in the utility's rate of return. Since investors and investment service companies are watching and attempting to determine the potential effects of increased competition, many of the more "at risk" utilities have experienced considerable price drops. This results in a paper loss for an investor or a real loss if the security is sold below the original price paid. These investors, in effect, have already suffered a loss that recovery of "stranded" costs could not compensate for in any practical way. The first question is: Are utilities compensated for the competitive risk they now face?

Point: Utilities Are Not Compensated

Utilities argue that they only recently became aware of the extent to which competition would reach (passage of the Energy Policy Act of 1992 (EPAct) being an often cited example of when notification occurred). The contention is that EPAct has so substantially increased wholesale competition and, together with recent state action, increased the potential for retail competition that it could not have been foreseen. These changes create a new market risk that substantially increased utility overall risk, and, because of its relatively recent occurrence, utilities are not currently being compensated for this additional risk.

It also has been argued that utility investors have not been compensated for the additional market risks that competition would bring because electric utility customers

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[4] Agustin Ros, John L. Domagalski, and Philip R. O'Connor, "Stranded Costs: Is the Market Paying Attention?" *Public Utilities Fortnightly* 134, no. 10 (May 15, 1996): 18-21. The authors, using a simple ordinary least-squares regression model, found a statistically significant negative relationship between utility market-to-book ratios (M/B) and stranded cost estimates. They concluded that "[i]ncreased utility exposure to stranded costs leads to a decrease in its M/B ratio. By year-end 1995, exposure to stranded costs had become a serious factor in investment decisions." Their data were of year-end 1995 stock prices and September 1995 book values only. They did not measure this through time or attempt to determine when it became a significant factor.

never "paid for the right" for utility assets to be treated in an asymmetric fashion.[5] This is because of the method that commissions typically use to calculate allowed rate of return. In the past, before competition, a utility could only earn a "fair" return for successful investments but received no return for unsuccessful (or disallowed) investments, hence an asymmetry was created that the utility was not being compensated for. Now the asymmetry continues because utilities may be subjected to the risk of losing from competition but the utility's gain from profitable decisions is still limited. The methods used by regulators to calculate fair rates of return, according to this argument, do not account for risk of a down-side loss from competition since a return is allowed only on economically successful investments. In this view, investors have not (and based on the method, could never have) been compensated for this asymmetric risk.

The asymmetrical manner in the way regulators calculate the cost of capital, it is argued, has placed utility investors in the same position as "junk" bond investors, but with a more limited opportunity to earn a higher return from good investments. Baumol, Joskow, and Kahn note that

> [j]unk bonds have to offer interest rates <u>higher</u> than investors expect actually to realize, on average, to compensate for the fact that some of the bonds will default. Regulators have not done that; they have not deliberately permitted returns higher than the cost of capital on the successful investments: but that's what it would have taken to compensate investors for the risk that competition might now wipe out the unsuccessful ones.[6]

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[5] William J. Baumol, Paul L. Joskow, and Alfred E. Kahn, "The Challenge for Federal and State Regulators: Transition from Regulation to Efficient Competition in Electric Power," December 9, 1994, filed as Appendix A with the Edison Electric Institute's comments on the FERC 1994 Stranded Cost NOPR. The original concept referred to the risk of disallowance and is from A. Lawrence Kolbe and William B. Tye, "The *Duquesne* Opinion: How Much '*Hope*' Is There for Investors in Regulated Firms?" 8 *Yale Journal on Regulation*, 113 (1991). Baumol, Joskow, and Kahn extended the concept to competitive risk as do Kolbe and Tye in A. Lawrence Kolbe and William B. Tye, "The Cost of Capital Does Not Compensate for Stranded-Cost Risk," *Public Utilities Fortnightly* 133, no. 10 (May 15, 1995), 26-28. This concept has received considerable criticism, see for example Ashley C. Brown, "Regulatory Risk: Is the Subject Still Relevant or Do Markets Govern?" 13 *Yale Journal on Regulation*, 403 (1996).

[6] Ibid., 36 (emphasis in original).

Regulators would have to allow a risk premium to compensate investors for this asset treatment. Baumol, Joskow, and Kahn note the difficulty in determining investor knowledge of competition: "[i]t is easier to assert the fact than to demonstrate it."[7] They, however, provide no empirical evidence of their own to support or refute the case of investor knowledge of competition.[8] As will be shown, this line of argument hinges on the reaction of financial markets and what and when investors knew about competition.

Counter-Point: Utilities Are Compensated

There are, of course, arguments that hold that utilities *are* compensated for the risk of retail competition. As noted, in some (perhaps many) states, rate of return reflects lost sales not only because of economic downturns but due to attrition as a result of forms of retail competition other than retail wheeling, namely, self-generation and municipalization. Some would contend that the risk of losing customers due to retail wheeling is just another form of retail competition, for which the utility is already being compensated through its risk of lost sales. Thus, the utility is already being compensated for lost sales due to already existing forms of retail competition. The possibility of further increased retail competition due to the provisions of EPAct can be argued to be only a difference in the specific form of a risk for which the utility receives compensation, not a difference in kind or degree.

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[7] They continue in a footnote that "it is relevant that commissions around the country did not mention competitive risk in their deliberations and findings on the cost of equity capital until very recently" (note 13, p. 37). As will be discussed, what matters is what occurred in financial markets, explicit commission pronouncements are irrelevant.

[8] As noted, Ros, Domagalski, and O'Connor determined that exposure to transition costs is being considered now and is affecting stock prices, but they did not attempt to find when it began to become a consideration or how this might be reflected in utility rates of return (Ros, Domagalski, and O'Connor, "Stranded Costs: Is the Market Paying Attention?"). To our knowledge, no such analysis has yet been conducted.

In such a case, however, it is the responsibility and the prerogative of the utility to request an appropriate rate of return on equity given the market risks that it faces. It is the responsibility of the state commissions to set a reasonable rate of return which the utility has an opportunity to earn. State commissions do not initiate rate cases, except upon a complaint or on their own initiative because rates are deemed to be too high. It is the responsibility of the utility to come forward to the commission and to seek adequate compensation for the risks that they incur if they believe that the return is inadequate with respect to their risk.

In addition, the asymmetry theorized by Baumol, Joskow, and Kahn and others could actually be in the opposite direction if a commission moves away from rate-of-return regulation and toward more incentive- or performance-based ratemaking. This could occur if the regulator allows recovery of transition costs while changing to incentive-based regulation. In this case the asymmetry switches to the utility being able to earn a high return (higher than under rate-of-return regulation) when it makes good decisions but faces a limited down-side effect. A symmetrical outcome distribution would either not limit the upside or downside (as in a competitive market) or have the same constraints on both profits and losses. In the future this asymmetry may be far more likely since most states that are now discussing industry restructuring are also considering performance-based ratemaking and at least some recovery of transition costs. A more symmetrical performance-based mechanism is described in Chapter 5.

It could also be argued that the utilities are already being adequately compensated for the additional increased market risks associated with municipalization and retail wheeling. The failure by many utilities to come forward and request rate increases due to increases in risk from retail competition can only indicate that utilities are already adequately compensated for those risks in their current rates. (Another alternative explanation is that these utilities realize that their embedded cost-based rates are already too high and that increasing rates will actually leave them worse off, particularly if customers with choices leave the system.) Indeed, there is every indication that state commissions have been generous in allowing utilities not only an opportunity to earn, but to *actually* earn, an overall rate of return and rate of return on equity that is more than adequate to compensate the utility for the risks that it faces. This may explain why many utilities have not had rate cases in many years.[9]

This has been reflected in actual earnings by utility investors. A study of common stockholder returns[10] of major electric and telecommunication utility companies found that 72 percent had an internal rate of return on investment higher than the average stockholder of major nonregulated U.S. industrial corporations over the 1972-1992 period. This includes change in stock prices and cash dividends. This period, of course, has been marked by considerable turbulence in both industries, including large disallowances, declining demand, sharply rising fuel costs, and higher capital costs. Whether this adequately compensated investors for increased market risk from competition is an open question. Also, there will be variation between companies. However, this does cast some doubt on the "junk bond" postulate discussed above since many investors have in fact been earning a higher return.

In addition, it could be argued also that utilities and their investors should have been aware of impending changes in the industry for some time, perhaps ten or fifteen years. There was the series of events, cited at the beginning of this chapter, that occurred in the mid-1980s that should have alerted utilities and their investors to the changes. These events include (to name a few), the beginning of competitive bidding by some states, discount rates offered to industrial customers (including "cogen killing"), increasing amounts of new capacity from independent suppliers, warnings of change from investor service organizations, and reduced regulation or deregulation in other regulated industries. There has been considerable time, in short, for utilities to prepare for action and investors to require higher returns or alternative investments. In fact, many utilities *have been* taking steps to reduce costs and prepare for increased competition and investor services are evaluating companies (in part) based on their analysis of the utility's ability to be competitive in the future.

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[9] Perhaps they prefer the higher rate of return (set back when the cost of capital was higher) they now receive to a larger rate base from new capital expenditures that *may* be allowed after a new rate case.

[10] Michael Foley and Ann Thompson, *Electric and Telephone Utility Stockholder Returns: 1972 - 1992* (Washington, D.C.: National Association of Regulatory Utility Commissioners, 1993).

As will be shown, the correct question is not: When did commissions begin to provide a competitive risk premium in utility rates of return? But rather: When did investors become aware of the impending changes in the industry and when did their changed expectations have an effect on financial markets and utility costs of capital?

Determining Competitive Risks in Financial Markets and Investor Expectations

Traditionally, electric utility stocks have been considered a "quasi-fixed income" security. Their monopoly status and relatively inelastic demand meant that they were a relatively safe and steady income source. Growth potential was not the main reason investors purchased these investments since it was viewed that, in general, there was limited opportunity for growth either within or outside the utility's service territory. This view has changed as the industry transforms to a more competitive structure. Electric utility stocks are becoming (or are already) more like industrial firms; they now have more potential for growth and decline as utilities contend to retain or increase their sales.

As noted, the question of investor awareness of competitive risk is an important factor in determining utility liability for transition costs. This is a complex question that can only be answered through a detailed and case-specific empirical analysis. Such an empirical analysis would involve judgment to develop an accurate picture of the factors that affect investor returns. Fortunately, many commissions are familiar with the techniques that such an analysis would involve. A complete explanation of commission rate-of-return determination, cost of capital, and financial market interaction is not provided here; only a brief explanation as to how this may relate to commission analysis of the issue of transition costs is discussed.

A utility's return to its investors and its cost of capital are determined by financial markets. An investor's return is the sum of the yield of a security (stock or bond) and the growth (or loss) on that security. Both yield and growth are dependent on the security's price, which may change each regular business day on financial markets. If a utility's investment becomes more risky, for example, and investors believe that the firm is less likely to maintain its dividend, the price of its stock will decline. In that case, investors that hold the utility's stocks or bonds lose, on paper at least, part of their investment. (In the extreme case, the price drops to zero if the firm goes bankrupt.) The expected return on such an investment increases and new investors now require an additional risk premium to become or remain investors in the firm. Overall, investments of similar risks will be priced in the market to have equivalent expected returns to investors. If something occurs that reduces risk, the security price will rise, decreasing yield. Clearly, moving away from franchised monopolies to a competitive industry structure will increase investor risk.

It may be the case that most regulators have not *explicitly* provided a competition risk premium when calculating rate of return. However, financial markets may have already taken the additional risk from competition, or competitive risk, into account. This is independent of whether a commission made an attempt to set the rate of return equal (or slightly above to account for "float" of securities) to the cost of capital. It is possible, contrary to Baumol, Joskow, and Kahn and others, that a competitive risk component is included. For example, assume that competitive risk does increase significantly and the commission did not set the return high enough. Some stock and bond holders will sell securities and the price will drop, raising yield to equal the cost of capital. Similarly, if a commission set the return higher than necessary, prices will be bid up reducing yield. *Commission policy obviously affects security prices, but financial markets determine the cost of capital.*

Thus, in this example, the utility and its investors have been, in effect, compensated for competitive risk. If this is the case, then past investors have already suffered either an actual loss if the security was sold or a paper loss if they still hold the investment. Compensating a utility for transition costs in this case would reward current share and bond holders, but not necessarily the investors who incurred the loss. The question remains: Have investors internalized utility competitive risk?

A utility investment advisor, writing in 1987,[11] states

> We are not yet certain that investors realize the possibilities or implications of unfettered competition, although they do ask, more and more, about whether utilities have competitive cost structures. The message is getting across that competition will produce winners and losers.[12]

For some time, rating agencies have been considering the competitive positions of electric utilities when making recommendations to investors. At a talk given before the NARUC Subcommittee of Executive Directors in 1993, a securities analyst for Moody's stated:

> Looking forward, it's clear there will be winners and losers. Our job at Moody's is to try to identify the losers and warn fixed income security holders of the risks involved. . .. Moody's is now in the process of examining the cost structure on a plant-by-plant basis of every rated utility. We believe that the results of this analysis will provide clues as to which utilities will have the flexibility to reduce their prices and which ones will be more constrained.[13]

In the same talk, the Moody's analyst continued, "[i]nvariably, credit risks increase and ratings fall as some companies are unable to make the transition to the Darwinian world of free markets." Clearly, hyperbole aside, security analysts have been well aware of the industry changes and adjusting the companies' ratings. When Moody's released a utility-by-utility study of transition costs,[14] there was a story about it

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[11] The intent here is not to find the latest remarks on the subject, but previous warnings of impending competition.

[12] Leonard S. Hyman and Heidimarie West, "Diversification, Deregulation, and Competition: Cost of Capital Implications for Electric Utilities," in *Deregulation and Diversification of Utilities*, Michael A. Crew, ed. (Boston: Kluwer Academic Publishers, 1989), 168. The authors state that their chapter was written in August 1987 (p. 179).

[13] M. Douglas Watson, Jr., "U.S. Regulated Utilities Under Attack," reprinted in *Electric Utility Sourcebook* (New York: Moody's Investors Service, October 1994).

[14] *Stranded Costs Will Threaten Credit Quality of U.S. Electrics* (New York: Moody's Investors Service, August 1995).

in *The Wall Street Journal.*[15] The paper stated that "no rating changes were announced [by Moody's] with the study because the 'relative cost exposures' of the companies analyzed have already been incorporated into current ratings." It would be difficult to find a utility investment advisor today that is unaware or not advising clients of the competitive risks that electric utilities now face.[16]

It would be a leap, of course, to assume that all utility *investors* are now aware of this; however, it is probably safe to assume that institutional and other large investors are aware and directly considering competitive risk or are considering the revised company rating by the investment services. It is probably also safe to assume that as investors make their buying and selling decisions, electric utility stocks and bonds prices are at least beginning to reflect the higher level of risks.

A Possible Empirical Test

As noted, the cost of capital is determined by financial markets where utilities compete for capital. Stock and bond prices are affected by the perceived risk and the return investors expect from a security. If the effect of competition has already been factored into investor decisions, then the prices of utility securities will already have reacted so that expected returns to investors already reflect a competitive risk premium. This is the case not because the commission explicitly added a competitive risk component, but because investors demanded a relatively higher return. They are now demanding a return that is comparable to other investments of similar risk level.

An analysis could be conducted to determine if the utility investors' return includes a competitive risk factor. A relatively simple way to determine the relative risk

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[15] "Deregulation May Cost Electric Utilities $135 Billion Over 10 Years, Study Says," *The Wall Street Journal* (7 August 1995).

[16] Goldman Sachs, Standard & Poor's, and others also consider transition cost exposure in their analysis and recommendations.

of a utility compared to the overall market could be to examine its beta.[17] It may be inferred by examining the behavior of the firm's betas over time whether there had been an increase or a decrease in competitive risk. However, this would only indicate that the utility is relatively more or less risky compared to the overall market.

A more appropriate way to explain historical trends in utility returns is through a multi-factor model.[18] While this involves a fairly sophisticated econometric analysis, many commissions and utilities have already been using a similar type of analysis when determining utility rate of return. This may be the only analytical way to determine whether utility investors are now compensated for competitive risk, to what extent, and for how long. This type of evidence could be used by a commission since it is generally consistent with existing evidentiary procedures and analyses.

Changes in utility stock and bond prices are based on investors' decisions on the best use of their money. Therefore, an empirical analysis would be superior to relying on only a subjective judgment of what investors should have known or speculating what they did know of the impending competition. Using historical data, the analysis would be testing for what investors have already accounted for in their expectations of increased competition.

There are many factors that increase or decrease a utility's risk that investors consider. Examples of regulatory policies that increase risk, or regulatory risk, include the possibility of a disallowance resulting from a prudence review or from an investment being found not used-and-useful. Competitive risks include the possibility of municipalization, co- or self-generation by industrials, fuel switching, loss of load, or retail customer access (retail wheeling) to other utilities. Commissions also adopt policies that reduce utility risk. Examples include fuel adjustment clauses and other automatic pass-through provisions, and revenue stabilization and DSM decoupling

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[17] Beta is a measure of the relative sensitivity of the price or return on an individual security to changes in the price or return on some market index. Betas below 1.0 imply less than average risk; betas above 1.0 imply greater than average risk.

[18] Leigh A. Riddick, "Using the APT and Related Multi-Factor Models to Estimate the Cost of Equity Capital for Utilities," *NRRI Quarterly Bulletin* 16, no. 1 (March 1995), 45-60.

mechanisms. The task of a multi-factor analysis would be to separate these various risk factors, isolating a competitive risk factor in particular, and testing its statistical significance.

It could be found in the analysis that: no competitive risk premium exists, a partial competitive risk premium exists, or a substantial competitive risk premium exists. Evidence that investors have adjusted to a greater level of risk could be indicated as a statistically significant shift variable in the econometric analysis. In this case, if commissions were to compensate a utility for transition costs, it would amount to a subsidy to existing investors. If no evidence is found to support the claim that investors have made the adjustment, then the issue and amount of compensation would depend on legal questions of utility responsibility to ratepayers to control costs and ratepayer obligation to the utility. Most likely, a good analysis would find some evidence for at least a partial adjustment. This could be used as the basis for a sharing arrangement between utility and ratepayers for future transition costs. This, of course, must be weighted with other considerations discussed in other sections of this report, such as legal obligations and mitigation incentives.

CHAPTER 5

SUMMARY OF FINDINGS AND POLICY RECOMMENDATIONS

Economic Efficiency

In a dynamic competitive market economy, assets become obsolete and are abandoned regularly. An important function of a market economy is that inefficient and obsolete practices and firms are either eliminated and replaced with more efficient and superior firms or forced to redirect their efforts to become more efficient and better managed. Overall, this results in society's limited resources being used in a productive manner. "Bailouts" of inefficient firms inhibit this screening process of a market economy and may only delay the inevitable. A truly competitive market provides stronger encouragement to utilities than is practical by regulation to reduce their cost, innovate, and lower prices for consumers. The drive to remain in business, become more competitive, and earn a profit is a much more effective disciplinary tool than regulatory inducements. Of course, this depends on being able to create an effective dynamic market with no or minimal market failures.

Chapter 2 discusses two general types of economic efficiency: productive or "static" efficiency and an overall or "dynamic" efficiency. Static efficiency is achieved when power is generated by the lowest-cost producer. Static efficiency requires only economic bypass of the utility's system and no "uneconomic" bypass. The marginal costs of the utility and alternative supplier and utility rates are assumed to remain unchanged and are optimal (all costs are minimized and there is no market power). Dynamic efficiency, in contrast, assumes that the utility's marginal cost can or does change over time and, if not optimal as might be expected under rate-of-return regulation, can be induced by market incentives to be reduced. Competitive markets are by nature dynamic where competitors are driven to control costs to retain or attract customers (as long as it is or is expected to be profitable).

The main economic argument for permitting more competition for electric generation is to encourage such a dynamic economic process. It was the dynamic-efficient effects in other deregulated industries that reduced costs and prices and provided consumers with substantial benefits. In other deregulated industries, in general, recovery of losses have not been provided. Exceptions occurred when, for example in the savings-and-loan industry, government policies contributed to the losses. Losses that occurred because of economic forces unleashed by technological change or deregulation were not generally given.[1]

Dynamic-efficient gains are potentially much larger than any static-efficiency losses. This is because the loss from "uneconomic" bypass, which only occurs in a limited quantity range, will likely be less than the gain to consumers from price reductions. Preference should, if the intention is to facilitate the development of a dynamic competitive market, be given to policy options that encourage a dynamic-efficient market, and avoid policies that impair it. This cannot be achieved by just focusing on static-efficiency losses. The only time static efficiency should be pursued in isolation is when generators of electricity are optimally producing electricity at minimum cost — an unlikely assumption given that electric utilities are generally cost-based regulated. The best way to achieve optimal efficiency is with unencumbered market incentives.

Specifically, allowing recovery of transition costs can negatively affect dynamic efficiency and impair the development of a competitive market in the following ways.

(1) *Blunts utility incentives to lower costs and mitigate transition costs*. This is a "moral hazard" problem from principal-agent theory. This occurs when a principal (the regulator) places the agent (the utility) in a position to act on their own initiative to do something that has some cost, but the principal cannot always (cost effectively) determine if the action taken (or not taken) is

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[1] Examples include the trucking and airline industries. The natural gas industry is an example of an industry that was allowed to recover *some* of its losses from customers because producers, pipelines, and local distribution companies were encouraged to enter into take-or-pay contracts that later turned out to be uneconomic.

appropriate or necessary.[2] For utilities that receive transition cost recovery this could occur primarily because the regulator, who has incomplete or imperfect information, is unable to detect when opportunities to reduce costs are either not taken, are not the best alternative, or are not pursued to full advantage. In a competitive market it is the dynamic drive to reduce costs to remain in business and expand profits that induces cost control. This process of competition, when it can be used or developed, is much better than a regulator at enforcing cost minimization. If a utility (or any business) is allowed to recover costs that would be lost if it loses customers, then this drive is significantly diminished.

At its worst, paying transition costs causes a perverse incentive to utilities to find and argue for recovery of all potential costs rather than lowering costs to become competitive (including costs that may not be appropriate for recovery). In effect, declaring that stranded costs are recoverable can set the utility on a path to maximize transition cost recovery, rather than lowering or minimizing costs. This institutionalizes existing utility uneconomic costs and rates rather than phasing them out. Strategically, commissions that declare in advance that recovery is possible are inadvertently sending the wrong incentive to the utility. In the natural gas industry, recovery of uneconomic take-or-pay contract costs was uncertain until it was settled in court.[3] In the interim, natural gas producers, pipeline companies, and local gas distribution companies worked toward solving the problem and reduced the overall amount.[4]

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[2] An example is health insurance. In this case, the principal is the insurance company providing benefits to the insured (the agents) who have an incentive to overuse health care services (seeing a doctor when they have a cold for example). The insurer must rely on the judgment of the insured or use incentives (such as co-payments) that are partially effective.

[3] AGD v. Federal Energy Regulatory Commission, 824 F.2d 981 (D.C. Cir. 1987).

[4] For more information on how transition costs were handled in the natural gas industry see Kenneth Rose, Mohammad Harunuzzaman, and Robert E. Burns, "Comments on the FERC's Supplemental NOPR on Stranded Costs by Public Utilities and Transmitting Utilities," reprinted in *NRRI Quarterly Bulletin* 16, no. 4 (1995).

(2) <u>*Acts as a barrier to entry and exit*</u>. Whether through entrance, access, or exit fees, recovery of a utility's sunk costs creates a barrier to entry. Efficient suppliers are discouraged from expanding or entering the market. Inefficient utilities are instead subsidized to continue to be the supplier or, if another supplier is chosen, to support assets that no longer have an economic or market value equal to its accounting or embedded value. In addition to the higher costs that customers are forced to pay, this also leads to inefficient self-generation as customers seek ways to avoid the fee. This is another form of uneconomic bypass, but is not prevented by an access fee since the fee itself is bypassable.[5]

Baumol, Ordover, and Willig state that "a defensible pricing standard [for telecommunications network elements] must be based on forward-looking economic costs, not historical book costs, because the expansion, contraction, entry and exit decisions of competitors efficiently and necessarily turn on expected prices and costs and have nothing to do with costs expended historically or reflected on accounting books."[6] This is consistent with the concept of dynamic efficiency and the development of a competitive market where suppliers are driven to optimally control costs, innovate, and offer lower prices and better service to consumers.

Even when the risk of uneconomic bypass can be prevented by an access charge, it may be more beneficial to have some small amount of static inefficiency *with* alternative suppliers in the market than no static-efficiency losses and no competition. This is because (as noted in Chapter 2) the

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[5] Contrary to the arguments for the creation of "nonbypassable" access fees, in reality customers, particularly large industrial customers, have the option of self-generation. In this case the regulator cannot enforce an access charge.

[6] From an affidavit by William J. Baumol, Janusz A. Ordover, and Robert D. Willig for AT&T, signed May 1996. The apparent contradiction contained in this statement with Baumol's work (coauthored with Sidak) on recovery of "inherited cost obligations" is not explained. See Chapter 8 of William J. Baumol and J. Gregory Sidak, *Transmission Pricing and Stranded Costs in the Electric Power Industry* (Washington, D.C.: The AEI Press, 1995). In Chapter 10 Baumol and Sidak argue that utilities should recover their "opportunity costs" that include "stranded investments and expenditures that are rendered unproductive by the competitive sale of bulk power" (p. 140).

presence of competitors in the market will encourage overall or dynamic cost efficiencies that could be much larger than any static losses.

(3) Creates an asymmetry between utility risk and reward. A risk/reward asymmetry is created if a commission allows a utility to retain more profit than in the past, but simultaneously guarantees that any potential down-side loss from competition will be recovered from customers. Commissions have indicated thus far in the restructuring debates that higher profits will be allowed with competition and performance-based regulation (PBR). By allowing more up-side potential profit while limiting the down-side risk distorts a utility's incentive in such a way that it would be less cautious than it would be when the utility incurs a loss itself. This means that consumers are ultimately responsible for bad outcomes. This removes the usual market discipline and accountability that encourages cautious decisionmaking. This asymmetry is similar to the one created in the savings-and-loan (S&L) industry that led, in part, to the largest single government bailout in history.[7]

Many, perhaps even most, utilities are likely to benefit from open and retail access and from a broader use of market-based rates. To make provisions for just possible losses that the industry will incur without considering the possible substantial gains adds to the regulatory asymmetry. For this reason, transition

[7] George J. Benston and George G. Kaufman, "Understanding the Savings-and-Loan Debacle," *The Public Interest*, no. 99 (Spring 1990). While there was a confluence of many factors, a major cause was that S&L managers were encouraged to adopt a high-risk, high-return strategy. This is because changes in the industry (caused by the economic conditions and government) increased profit opportunities while deposit insurance limited losses. If a venture succeeded the S&L kept the gain; if it failed, the loss was shifted to the government deposit-insurance corporation (FSLIC). The authors note that

> "[o]ne of the major reasons for the size of the S&L crisis is that authorities were reluctant to enforce some forms of market discipline — in particular, insistence on adequate capital reserves and the prompt liquidation or reorganization of economically insolvent S&Ls — that the market could not enforce itself under the deposit-insurance system." (p. 86.)

cost recovery may conflict with the goal of increasing the use of PBR. A PBR mechanism that more carefully balances risks and rewards is discussed later in this chapter.

Regulatory Symmetry

The examination of the origins and content of the regulatory compact finds little basis for the claim that utilities are always entitled to cost recovery and a return on their investments. Indeed, a strong argument could be made that to be consistent with past treatment and the manner in which the compact has been interpreted by many states, full recovery of transition costs is what would be inconsistent. There is no “entitlement” to “stranded” costs expressed or implied by the regulatory compact. The only entitlement granted was the revocable privilege to serve an exclusive territory. The obligation to serve stems from this privilege. The compact is not an agreement to pay all costs (prudent or otherwise) because of the obligation to serve. It is much more complex than simply “I am obligated to serve, therefore customers are obligated to pay all my costs.”

As revealed in the discussion of court cases and commission decisions the answer to treatment of lost utility value is not cut and dried. But a general path can be found that is consistent with these past treatments and, in particular, the finding of *Duquesne* that equated risk to the utility and the method of valuation. If a state used or uses a “pure” prudent-investment test for valuing utility property, then the utility most likely received a lower return on its investment in rate cases. This is because the utility was subject to very low risk of loss of its investment and the rate of return should reflect that. For transition costs, the utility in this situation should expect to at least recover its costs and perhaps a return. Conversely, if the state used or uses a “pure” used-and-useful test, than the higher risk would be reflected in a higher rate of return. In this case the utility should expect no recovery of the investment costs or a return. The utility was already compensated for the risk that the investment’s original cost may not be recovered, even in a market situation that did not exist when the investment was made.

However, most states do not use a "pure" form of either valuation method, rather they use a combination of both. This is the primary reason why the treatment varies for analogous situations across states and sometimes even within states. With respect to transition costs, states may consider the return given to the utility and allow total, partial, or no recovery of the costs, and either return on the allowed portion or no return at all. This is not inconsistent or opportunism on the part of commissions, but very consistent with past treatment. This points out the importance of an analysis of the risk/return that the utility was subject to when determining transition cost treatment. This balancing of the risk and reward or penalty can be termed "regulatory symmetry."

While introducing competition in retail electric markets may appear to have a negative affect on electric utilities; this presupposes that the utility either cannot or will not take steps to lower its costs and its rates. Again, many, perhaps even most, utilities in fact will have opportunities to earn *higher* earnings under a regulatory regime with incentive- and market-based rates. The focus should not be on just the possible losses by utilities. This underscores the importance to have the risks be commensurate with the reward or penalty in the interest of fairness to ratepayers and to maintain proper incentives for good decisionmaking. As just discussed, if a commission commits to full recovery of transition costs, while simultaneously allowing a utility to retain more of the benefits of being competitive, a potentially harmful incentive asymmetry is created. That is, if the utility is competitive it is rewarded, if it is not, it is made whole from a transition cost payment and is not penalized.

The debate on transition costs thus far implies that the commission or legislature is imposing costs on the utility when it moves to open or direct access or that regulators or customers *cause* costs. This has shifted the focus away from the origin or controller of these costs, the utility. In an economic sense, retail access and competition do not impose costs — rather they *expose* costs that are uneconomic relative to alternative suppliers. In many respects, it is the tariff or rate that is "stranded," not the investment. As noted, an important function of competitive markets is to screen out costs and suppliers that have above-market prices. These may include costs that would have remained hidden if the utility's monopoly was allowed to continue. Competition does not cause the uncompetitive supplier's higher costs any more than athletes can blame their competitors for losing. Currently uncompetitive utilities, like the uncompetitive athlete, can decide to either find ways to improve their performance and competitiveness or withdraw from the competition.

The compact has been continuously rebalanced to accommodate changing conditions in the industry. Clearly, some kind of rebalancing is needed again. A means of recasting the compact that is consistent with past treatment of assets but does not unreasonably impair the development of competition in a PBR context is presented next.

A Performance-Based Recovery Proposal[8]

This proposal is designed to minimize (but does not eliminate) the impact on dynamic efficiency when recovery is allowed. This method may be used to set prices for distribution and transmission services (including ancillary services) that are likely to be regulated. All customers, including those who now purchase power from alternative suppliers, will pay the transition costs, not just residential or core customers who remain on the utility's system. This method assumes that the commission has already determined that the utility should recover transition costs and how much, based on an analysis, is to be recovered.

Performance-based regulation (PBR) is a relatively new term used to describe a general category of many different types of noncost-based rate regulation. They include targeted incentives, yardstick regulation, and price caps. The main feature of PBRs is that the firm is compared to and rewarded or penalized based on its performance relative to others in the industry. This is in contrast to traditional cost-based regulation where the firms costs are primarily examined in the context of that firm only.

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[8] This section is based on work by NRRI for the Rhode Island Division of Public Utilities and Carriers.

There is a series of questions that state and federal regulators now face when considering restructuring of the electric utility industry and what type of rate regulation should replace cost-based rates:

- What form of rate regulation is most compatible with more competitive electric markets?
- How can customers with relatively few or no choice of suppliers benefit from competition and its expected cost savings?
- How can the so called "stranded cost" problem be solved in such a way that is fair to both utility shareholders and customers? and
- How can this be done in such a way that economic efficiency is not unduly sacrificed?

There is a general consensus in the regulatory community today that cost-based regulation is ill suited to solve the problems raised by the above questions. The limitations of cost-based regulation are now well known and documented. These include a lack of incentive provided to the utility to control or reduce costs and adopt new and innovative technologies, the tendency of market risks to be shifted to ratepayers, the lack of a reward to the utility for good decisions, and a high administrative costs for both the regulated and the regulator, because of its litigious and deliberative nature.

While there are a variety of PBRs available, price caps appear to have several distinct advantages at this time for the electric industry:

- they have better incentives for cost reduction and control,
- they have been used in other industries for years so that the advantages, potential obstacles, and other issues that arise during implementation are well known,
- they are relatively simple to administer compared with cost-based regulation,
- they allow more price flexibility for the utility to arrange contract terms with large retail customers (as long as it is below the cap),

- they protect customers with few or no practical choice, and
- they are a good transition tool to more competitive markets.

As a transition tool, a commission can implement a price cap for individual customer classes that will protect captive or core customer groups from cross-subsidizing more competitive customer classes. This cross-subsidizing can be in the form of costs being shifted from the more competitive markets to the less competitive and revenues from the less competitive being shifted to the more competitive (such as residential customers subsidizing industrial customers). Another advantage is that the price cap can be used at the same time to test the extent to which competition is developed in a given market. If, for example, the actual price that large industrial customers pay is considerably below the price cap set by the commission, then the market is likely to be competitive and complete price decontrol should be considered for that class of customers.

Ideally, the transition cost problem can be solved in such a way that the expected cost savings from competition and better incentives from a PBR can be used to reduce the size of the transition costs and, eventually, eliminate these costs altogether. A mechanism is introduced here that links the price-cap mechanism with the recovery of transition costs. The price cap proposed here has two basic (and separate) components: the basic price-cap formula and the profit-sharing equations. Each is described below.

The Basic Price-Cap Formula

The price-cap formula provides the percentage of annual change in the price for a group of customers based on three main components: a price index, a productivity index, and an adjustment factor for idiosyncratic costs or benefits. This can be expressed in the following formula as:

$$\Delta P_{it} = (PI_{(t-1)} - X_{(t-1)}) \pm Z_{(t-1)} \tag{1}$$

where

ΔP_{it} = percentage change in the price of electricity for customer class i for period t,

$PI_{(t-1)}$ = price index for latest reporting period,

$X_{(t-1)}$ = productivity offset calculated from latest reporting period data, and

$Z_{(t-1)}$ = adjustment factor for company specific costs such as transition costs from the latest period.

The price index is a general inflation measure and can be drawn from Bureau of Labor Statistics (BLS) data on the Consumer Price Index (CPI) or the Gross Domestic Product Implicit Price Deflator. The most recent reporting period is used and should be of sufficient length of time (one year, for example) so that monthly variations do not over or under state the actual rate of price level changes. The productivity offset is intended as an overall measure of net productivity change in the electric power industry relative to the overall economy's (productivity is defined as the industry's output divided by its inputs).

The bracketed terms ($PI_{(t-1)} - X_{(t-1)}$) together are intended to estimate the industry's increase in *costs* during the period. An alternative and more precise method a commission could use in place of the price index and productivity terms is an index of electric utility costs. However, for tractability reasons, most price-cap plans use a broad economy-wide measure of price change with a productivity offset. The logic behind this method is that since a *price* index is used rather than a cost index, an offset is required to estimate net cost increase (that is, net of any productivity change). If an economy-wide price index is used, the productivity offset should reflect the difference between the long-term productivity trends in the economy as a whole and the total factor productivity trend in the electric industry.[9]

In practice, commissions have used the productivity offset not in a precise and exact way, but rather as an adjustment factor. A commission may decide, for example, that prices under a price-cap mechanism should be less than they would have been if the utility were still cost-based regulated but still allow sufficient revenues to attract investors. In this case, a commission would raise the productivity offset by an amount sufficient to meet this goal. The justification for this is that since price caps will encourage cost reductions, not all the benefit should go to the utility's shareholders. An additional argument for adjusting the offset is that historical industry productivity changes reflect the trend of a regulated industry prone to some lethargy and inefficiency and do not reflect the expected future (or desired) growth in productivity that will likely be induced by competition. By setting a more stringent target, the utility is required to increase its efforts to reduce costs. An example of this kind of adjustment was the Federal Communications Commission's "consumer dividend" of 0.5 percent added to a productivity offset of 2.5 percent in a price-cap plan for AT&T's interexchange activities. This was intended to guarantee that customers would shared the performance improvement resulting from the increased incentives.[10]

The Profit-Sharing Equations

The profit-sharing equations are a secondary check on the utility's earnings and are determined separately from the price caps. A commission would set an allowed or target cost of equity capital and a "dead-band" range around a mid-point estimate. When the utility's earnings (Y_e) are *above* the upper bound (Y_U), the utility will be

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[9] Wayne P. Olson and Kenneth W. Costello, "Electricity Matters: A New Incentives Approach for a Changing Electric Industry," *The Electricity Journal* 8, no. 1 (January/February 1995).

[10] Herb Thompson, Mark Newton Lowry, and David Alan Hovde, "Total Factor Productivity in the Investor-Owned Electric Utility Industry: 1975-1992," *NARUC Biennial Regulatory Information Conference Proceedings*, Vol. II (Columbus, OH: The National Regulatory Research Institute, 1994), 445-60.

required to share the "excess" profit with ratepayers. This is reflected in the following formula,

$$\begin{gathered} \textit{when } Y_e > Y_U \textit{ then} \\ Y = Y^A = Y_U + g(Y_e - Y_U), \end{gathered} \tag{2}$$

where

Y_e = unadjusted earned rate of return on equity,

Y_U = rate of return on equity at the upper boundary of the dead-band region,

Y = rate of return on equity after price adjustment,

Y^A = allowed rate of return when the unadjusted rate of return is above the dead-band region, and

g = sharing ratio equal to the share of the difference between the unadjusted rate of return and the boundary rate of return; $g = 0$ when the unadjusted rate of return lies within the dead-band region.

When the utility's earnings are *below* the lower bound set by a commission, there is a symmetrical sharing of the earnings "deficiency" between shareholders and ratepayers,

$$\begin{gathered} \textit{when } Y_e < Y_L \textit{ then} \\ Y = Y^B = Y_L + g(Y_e - Y_L), \end{gathered} \tag{3}$$

where

Y_L = rate of return on equity at the lower boundary of the dead-band region, and

Y^B = allowed rate of return when the unadjusted rate of return is below the dead-band region.

When the utility's unadjusted earnings are in the dead-band region there is no sharing, that is, the utility is allowed to retain its actual earnings,

$$\begin{gathered} \text{when } Y_L \leq Y_e \leq Y_U \text{ then} \\ Y = Y_e \end{gathered} \tag{4}$$

Figure 5.1 illustrates two examples of the profit-sharing mechanism. Example one is on the right side of the diagram. The utility's unadjusted earned rate of return on equity (Y_e) is 13 percent, this exceeds the upper bound of the dead-band region (Y_U) of, in this example, 11 percent; thus, Equation (2) applies. Inserting these numbers into Equation (2) results in an allowed rate of return (Y^A), with g equal to 0.5, of 12 percent.[11] Example two, on the left side of the diagram, is an example of the profit-sharing mechanism when the unadjusted earned rate of return is below the dead-band region (less than Y_L of 6 percent in this example) since the utility's Y_e is now 4 percent. In this case, Equation (3) applies. With g again equal to 0.5, the allowed rate of return (Y^B) is now 5 percent.[12] If the utility's unadjusted earned rate of return was in the dead-band region, then Equation (4) would apply. In this case (not shown in the diagram), the unadjusted and allowed rate of return on equity would be equal.

The profit-sharing equations may be a transitional tool only and could be phased out over either a prespecified period of time or after it has been determined by a commission that some or all electricity markets have developed sufficiently to protect consumers.

[11] That is, 11 + 0.5(13 - 11) = 12 percent.

[12] That is, 6 + 0.5(4 - 6) = 5 percent.

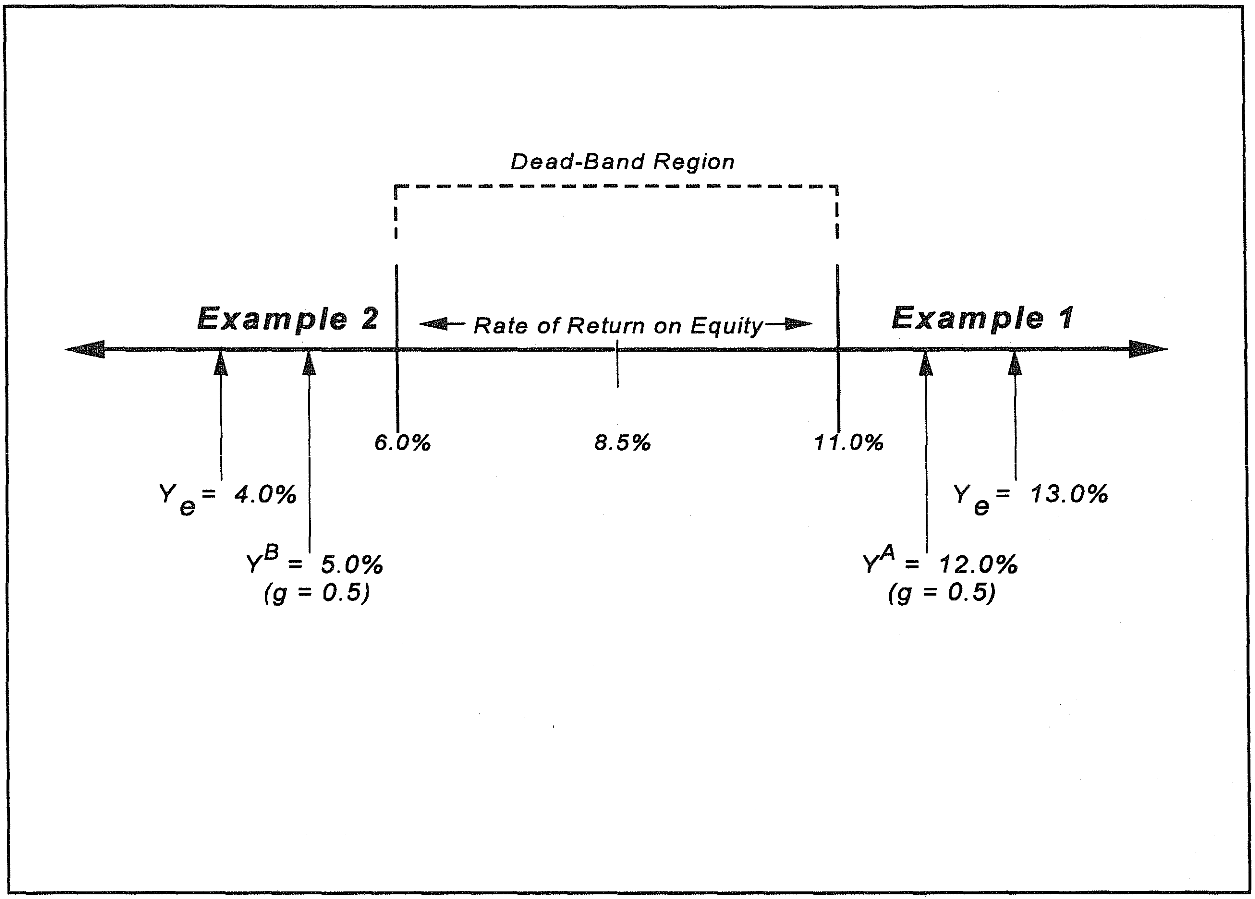

Figure 5.1.   Two examples of the profit-sharing mechanism.

The Link Between Transition Cost Recovery and the Price Cap

Two primary limitations of transition cost recovery that have been discussed — the poor incentives that the utility receives to minimize and mitigate transition costs when recovery is assured and the asymmetry between risk and reward — are specifically addressed by this PBR mechanism. While the "first best" economic solution (in terms of dynamic efficiency) would be to not allow transition cost recovery and move to competitive markets as quickly as possible, a commission may wish to have a transition period where rate-base/rate-of-return regulation is phased out while phasing in competition and PBRs. This PBR mechanism is intended for such a transitional period.

In the proposed price-cap mechanism, there is a direct link between the Z factor in the basic price-cap formula and the g, or sharing factor, in the profit-sharing equations. This alleviates (although it does not completely eliminate) the limitations to transition cost recovery. The Z, expressed for example, as a percent of total cost, is intended to be inversely proportional to g. For example, if the Z includes all or nearly all of the utility's transition costs, then g should be relatively low and the dead-band region relatively narrow. Conversely, if the utility recovers relatively less of its transition costs, then the g should be relatively larger and the dead-band region wider. Complete recovery of Z with a g equal to zero would approximate a rate-of-return/cost-based regulation outcome. No transition cost recovery with a g equal to one, would be a close approximation to a competitive market outcome (except, of course, for there being a price cap). A commission may consider giving the utility a choice of where to set Z with a corresponding nonoptional g factor paired with it.

A commission may also consider reducing Z over time (say, four or five years) while increasing g proportionately. This allows the utility to retain more of the profits and incur more of the losses outside the dead-band range. When g approaches one, a commission may then discontinue the profit-sharing component of the price cap. (Of course, a commission may want to continue with profit sharing for other reasons.) At that point there would no longer be any transition cost recovery.

Implementation Issues

The utility, since it can benefit from lowering its costs and because the price cap allows charging a price under the cap, is given more of an incentive to retain the customer — even at reduced revenues. This may be preferred to losing the customer entirely, which may happen with a simple pass-through recovery mechanism.

There are explicit tradeoffs throughout the two equations. These tradeoffs should be considered when designing and implementing a price-cap mechanism. Raising Z should correspond with a proportionately lower g. If a commission chooses to have no Z factor at all in the price-cap formula, more of the risk of transition costs that results from market outcomes will be placed on the utility with a higher g, but so will the reward from positive outcomes. With a high Z and low g, more of the risk is placed on the ratepayers but they also receive a higher share of the benefits from positive outcomes. A commission may start in the first year with a high Z, for example, 70 percent of transition costs, but with a low g, of 0.3. In the second year Z may be lowered to 50 percent and g raised to 0.5 and so on.[13] After four or five years the Z and, perhaps, the profit-sharing component may be eliminated.

Another important consideration is the width of the dead-band region. If recovery of transition costs is relatively high, the dead-band region should be narrow. If recovery is relatively low (as a percent of total transition costs), then a commission may allow a wider dead-band region. The logic is the same as for the tradeoff between Z and g; if the utility is shouldering more of the transition costs then the region should be wider to allow it to retain more of its earnings. If the utility is recovering all or most of its transition costs, then the region should be narrower so that utility earnings are more restricted.

While this price-cap mechanism would not achieve the dynamic-efficiency gains that could occur from a competitive market, it would relieve some of the disincentives from an automatic passthrough of transition costs. This method also makes the risk/reward tradeoff explicit and eliminates the asymmetry caused when incentives are combined with transition cost recovery.

[13] It is possible, of course, to have an asymmetrical reward and penalty. For example, a commission may choose to have a higher g for earnings above the dead-band region and a relatively lower g for below the dead-band region. For the reason of symmetry discussed in this chapter, this is not recommended.

If Transition Cost Recovery *Is* Allowed

The basic findings of this report are that (1) recovery of transition cost damages economic efficiency, and (2) recovery is not always required under the regulatory compact. However, if a commission decides to allow transition cost recovery, in addition to using the above PBR mechanism, several other of the following points can be made based on the report's conclusions.

(1) Do not commit to the amount of the transition costs in advance. Estimates of transition costs project a future market price for generated power and compare it with the current utility rates. This is misleading for several reasons. First, and most obvious, is that the forecasted price could be off substantially. It is unlikely that anyone can predict how retail markets will develop or what prices will be in the future, especially for a market that is yet to be defined.

Second, and perhaps of more importance in a developing competitive market, is that the utility's rate is unlikely to represent a "best practice" price that would be expected to develop in a competitive market. A plant or a portion of a plant is not "stranded" until the cost cannot be cut sufficiently to compete with alternative sources; that is, a plant is only "stranded" when its marginal cost is above the market price. Most plants, however, will still have a significant useful life providing power, but perhaps at a lower price than the old regulated rate and perhaps at a reduced level of output. It is unlikely that an entire plant will be "stranded," as some estimates assume, and the plant completely worthless. Estimates are likely to overstate the amount of transition costs because they do not take into account the decrease in costs that will result from competitive pressure.

Since it is difficult, if not impossible, to estimate the magnitude of the utility's response in a competitive market and the future market price for power, it is better to calculate the amount after-the-fact. Therefore, any calculation made for transition cost recovery should be retrospective or, if it is done in advance, with a true-up mechanism and an after-the-fact review. The incentive problem, however, remains.

(2) *Place a time limit on when recovery will be allowed*. Even in the most generous (to the utility) of interpretations of the regulatory compact, it could not be argued that ratepayers are liable forever for utility uneconomic costs. Because of the move to competition in the industry, at some point, regulators will have to rely on the market to determine asset value, not past accounting or book value. If generation costs continue to fall, for example, ratepayers should not continue to be liable. Consistent with the findings of Chapter 2, if transition costs are allowed, it should be for as short a time as possible; two to four years for example.

(3) *No recovery should be allowed for avoidable operating costs or for return on investment*. Commissions, when calculating transition costs should be careful not to include any costs that will be avoided when the utility is not supplying the power. If a "lost revenue" approach is used, for example, all operating costs should be subtracted as well as any revenue from the sale of generation services to others. Likewise, any return on uneconomic investments should be excluded from recovery. A preferred approach may be to take the undepreciated balance and amortize it over a period of years, taking the asset out of rate base. Simply put, the utility should not earn a return on uneconomic assets.

(4) *Link recovery of transition costs with the level of risk the utility is taking*. For reasons already explained, there should be some symmetry between the recovery of transition costs and any benefits from competition or incentive regulation. The above PBR mechanism is designed to match risk with reward. Alternatively, in a cost-based framework, the commission may simply set the rate

of return very low (comparable to low-risk financial instruments such as U.S. Treasury bills).

(5) *If possible, do not allow full recovery*. Any amount less than 100 percent recovery improves utility incentives to reduce costs and prices. As noted in Chapter 2 and earlier in this chapter, this is because of the problems associated with recovery and utility incentives. Moreover, since the utility's incentive is to maximize recovery, these costs are likely to be (but not always) overstated. There is potential for the utility to deliberately overstate the amount because they expect to receive a lower number no matter where they begin; the incentive is to "aim high."[14]

(6) *The burden of proof on verification of costs should be on the utility*. Another asymmetry problem is in information. As a practical matter, utilities will always have better access to information than commissions. Regulators often have several electric utilities plus natural gas, telecommunications, water, transportation, and other companies to oversee. Because of limited staffs and budgets, it is extremely difficult to keep track of all utility activities. The starting premise should be then for utilities to show (again, preferably after-the-fact) when any transition costs have occurred. This is after the commission has decided what general type of costs will be recoverable.

[14] Those experienced with rate-of-return regulation will recognize this problem as basically the same as when utilities overstate claims for rate of return in rate cases.