NATURAL RESOURCES JOURNAL

Volume 37
Issue 1 *Symposium on Electric Industry Restructuring*

Winter 1997

On Stranded Cost Recovery in the Deregulation of the U.S. Electric Power Industry

Michael T. Maloney

Robert E. McCormick

Raymond D. Sauer

MICHAEL T. MALONEY, ROBERT E. MCCORMICK, & RAYMOND D. SAUER*

On Stranded Cost Recovery in the Deregulation of the U.S. Electric Power Industry

Deregulation of the United States electric power industry has enormous potential to reduce the rates which consumers pay for electricity.[1] Two facts about current electricity prices make this obvious. First, the average price paid for electric power is significantly higher than the long run average cost of production. Second, price differences that exist between markets have nothing to do with the current costs of supplying power and everything to do with the exclusive rights granted to power companies under the current regulatory regime. Deregulation of electric utilities can unleash strong competitive forces. If left unfettered, competition will reduce regional price variation and lower price towards cost.

The price declines expected under deregulation will reduce the profits of electric utilities that receive high prices for their output. For some firms the financial repercussions will be serious. In light of this, some industry interest groups and economists have argued that, while deregulation may be desirable, electric utilities must be shielded from its financial implications. Specifically, it is argued that utilities should be compensated for what has come to be called stranded costs.

The term "stranded costs" is a new entrant on the economic scene, emerging as an issue only in the context of electricity deregulation. At bottom, the concept refers to an investment made under regulation whose value will not be recovered under prices determined in a deregulated environment. This would seem to be a general condition associated with deregulation of an industry. It is thus odd that little or no attention was paid to stranded costs in the discussions on airline deregulation, trucking deregulation, and the breakup of AT&T.[2] An anecdote from the telephony industry illustrates the point. In the early and middle 1970s, MCI and AT&T invested substantial sums in the installation of microwave towers. The

---

* We can be contacted at (864) 656-3430, 656-3441, 656-3969 or maloney@clemson.edu, sixmile@clemson.edu, or sauerr@clemson.edu. The fax number is 656-0948. We acknowledge the assistance of Chad McGowan, Elvino Mendonca, Laura Speake, and Emily B. Wood.

1. This is the major conclusion of our monograph, MICHAEL T. MALONEY, et al., CITIZENS FOR A SOUND ECONOMY FOUNDATION, CUSTOMER CHOICE, CONSUMER VALUE: AN ANALYSIS OF RETAIL COMPETITION IN AMERICA'S ELECTRIC INDUSTRY (1996). This monograph is the basis and background of the analysis and conclusions we present here.

2. The divestiture of AT&T was an antitrust case, not a legislative mandate. Hence, it is not exactly comparable to deregulation in airlines, trucking, and electricity.

value of these towers was virtually destroyed by technological advances in fiber optic cable and deregulation of the long-distance telephone market. Indeed, Sprint showed footage in its television advertisements of microwave towers being dynamited. Yet there was no effort to obtain recovery for the lost value of stranded towers when the FCC deregulated the long-distance market.

Why the issue appears now and not in the first cases of deregulation is an interesting question, but one we leave unanswered here. Even so, the fact that there is little intellectual history of stranded cost recovery is revealing. Indeed, the main issues are ones of equity and morality, not economics and efficiency. While some analysts have tried to make stranded costs into an economic issue, their arguments do not bear close scrutiny as we demonstrate below.

In this paper we address the following issues. First, we provide an operational definition of stranded costs. We use this definition along with empirical evidence from financial markets to estimate the magnitude of stranded costs. We then briefly examine the history of electricity producers in financial difficulty. Finally, we discuss what economics has to say about the consequences of compensating and the means of compensation for stranded costs. Does de-regulation threaten the nation's ability to efficiently produce electricity? Provided that compensation does not get in the way, the economics of stranded costs indicates that the answer is no.

1. A Functional Definition of Stranded Costs

In the extreme, stranded costs could be defined as any investment that will be less valuable under competition than under regulation. Hence, any decline in the value of assets in the move from regulation to competition would be cause for reimbursement. Public policy has not viewed the problem in this light. Two academic writers who have argued that utilities should be allowed stranded cost recovery define these stranded costs as "those costs that the utilities are currently permitted to recover through their rates but whose recovery may be impeded or prevented by the advent of competition."[3] We choose a definition that is slightly more functional. To us, the proper measurement of stranded costs compares the value of all the firm's utility assets in the regulated environment with the value of these same assets in competition.

In the regulated regime, investor-owned public utilities are allowed to make a "fair" rate of return on prudently invested capital. In practice,

3. William J. Baumol & J. Gregory Sidak, *Stranded Cost Recovery: Fair and Reasonable*, PUBLIC UTILITIES FORTNIGHTLY May 15, 1995 at 20. *See also* BAUMOL & SIDAK, TRANSMISSION PRICING AND STRANDED COSTS IN THE ELECTRIC POWER INDUSTRY, (1995).

regulators set the price of electricity so that the utility receives enough income to pay its expenses plus a return of its fixed investments. In effect then, historical or accounting costs of installation determine the current market value of capital. Regulators adjust the revenue stream up or down to insure that public utility operators earn the approved rate of return on the book value of capital.

Under competition, a firm builds a plant on the expectation of future income and cash flow. The hope of this future stream of income motivates the investment. Once the physical capital is in place, and assuming that it has no alternative or salvage value, its economic value is determined by the future cash flows. A simple example will help to elucidate the principle.

FIRST PRINCIPLES OF VALUATION

Suppose a firm is contemplating the construction of a facility. The firm expects that it can generate $100,000 per month of gross sales using this facility. Labor, materials, taxes and other inputs are expected to cost $75,000 per month to operate the facility. This leaves the firm with $25,000 of net cash flows after all its operating bills are paid. If the underlying capital investment will have no alternative uses once in place, its capital or market value is the present discounted value of $25,000 per month as far into the future as the situation is expected to exist. For purposes of the example, let's assume that the facility and the sales and costs are expected to continue for 10 years, 120 periods. If the appropriate discount rate on these cash flows is 12 percent per year or 1 percent per month, then the market value of this capital in place is given by the formula:

$$V=\sum_{i=1}^{120}\frac{(\$100{,}000-\$75{,}000)}{(1+0.01)^i}=\sum_{i=1}^{120}\frac{(\$25{,}000)}{(1+0.01)^i}=\$1{,}742{,}513.$$

The decision to build the plant is transparent in this simple example. If the firm can construct the plant for less than $1.74 million dollars then it is a good investment, that is, a positive net present value project. The cash outlays on capital to construct the plant, if they are less than $1.74 million, are dominated by the expected value of the future net cash flows. If the firm makes the investment, under this scenario, the equity value of the firm will increase by the differential between the cash outlays on construction and the present value of the future expected net cash flows.

Assume that the plant can be built for $1 million. What is this plant worth? There are two basic ways to answer this question. One is to place a historical value on the costs of putting the asset in place. Call this the historical cost accounting method. The cost accounting method says that the value of the plant is the accounting dollar cost of building the facility. Accordingly the plant is worth, and is carried on the books of the company, as $1 million of assets.

Alternatively, there is the discounted cash flow or net present value approach. This valuation approach is based on the idea of efficient capital markets. It asks, what could the asset be sold for? Since the value of the expected net cash flows is $1.74 million, economic theory argues that in an efficient capital market a buyer can be found who will pay this sum. In this world, the plant is worth its market value, which is $1.74 million.[4]

Let's take this scenario down the road five years. First, assume that the cash flows have accrued at the expected rate and that there is no change in expectations about the gross income or costs over the remaining five year life of the facility. Second, assume that based on the appropriate accounting rules the facility has been depreciated linearly at an annual rate of 10 percent over the 10 year life. What is the plant now worth?

In accounting terms, the plant is worth its original cost of $1 million minus its depreciation, which is five times 10 percent or 50 percent. The current value of the plant for accounting purposes is $500,000. However, in value terms the plant is worth the net present value of the future cash flows. There are five years left of production where the facility produces a net income of $25,000 per month. The present value of $25,000 a month for five years at a discount rate of one percent per month is:

$$V=\sum_{i=1}^{60}\frac{(\$25{,}000)}{(1+0.01)^i}=\$1{,}123{,}876.$$

At the end of five years, the net present value of the expected future cash flows is $1.12 million. In sum, the accounting approach says that the plant is now worth $500,000 and the valuation approach says that the plant is worth $1.12 million.

To understand the nature of stranded costs, now imagine that the expected revenues from the plant fall dramatically. Suppose the output of the plant declines significantly in price. Adjusting for this price change, the gross revenues fall $75,000 per month. Costs also fall but not as much; assume they are now $70,000.[5] The net cash flow to this enterprise is now $5,000 per month instead of the original $25,000. The present value of this

4. In more elaborate valuation analysis things like taxes, working capital requirements and capital structure are included. We abstract from these here in the interest of simplicity and because they do not affect our conclusions.

5. Costs are lower because the plant produces less output and hence less labor and materials are used.

sum for the remaining five years is $224,775.

The plant which originally cost $1 million to build and which is being carried on the accounting books as having a value of $500,000 is now only worth $224,775 in the marketplace. The market value of the plant has plummeted because the price of its output has gone down.

THE VALUATION OF STRANDED COSTS

Having gone through this exercise, we are now in position to be precise about the definition of stranded costs. Consider Table 1 where the pre-ceding discussion is depicted and stranded costs are computed. The stranded costs are computed as the difference between the current market value of the asset in its productive employment and the historical cost of the asset depreciated through time using the approved accounting depreciation schedule. Because the product has a lower price than anticipated, cash flows are lower. Lower cash flows mean lower fair market value. The fair market value of the asset is now less than its accounting or book value. Its market value is now $224,775.[6] On the books its appears to be worth $500,000, so it appears that the owners have lost $275,224. These are the true stranded costs.

In an unregulated environment, this capital value loss is borne by the owners of the business. The market value of the company declines from $1,123,786 to $224,775. Based on market valuation, they lose $899,101. Their wealth is lower, but nothing else changes. By construction, the plant has no alternative use and no salvage value. The opportunity cost of using the facility in its present use is therefore zero. Any income generated in excess of the variable operating costs accrues to the owners of the business. The owners, although they are now poorer, are better off running the plant than idling it. This is also revealed in the last two rows of Table 1.

If the business is abandoned at any point in the ten-year period, the company has no equity or market value. If, at the five year point, the original revenue estimates hold and the facility is operated, then the equity value is $1,123,786. If, at the five year point the new revenue stream exists and the facility continues to operate, then the equity value is $224,775. Under any scenario, the company is worth more money if it continues to operate the facility.

An important distinction is created. Financial losses are one matter, continued viability and operation of an enterprise another. Stranded costs can never be so large as to force the shutdown of a business. So long as the

6. It is important to recognize that we have built this scenario upon the assumption that the capital has no alternative uses nor any salvage value. It is worthless for any purpose except the production for which it was built.

capital value of the business is positive, it pays the owners to operate the facility. Said another way, so long as gross revenues exceed current operating costs, it pays the owner to operate. To repeat, no facility will be abandoned or idled because of its sunk or stranded costs. At least that is the conclusion of basic economics and the modern theory of finance.

Table 1 shows the calculation of stranded costs based on the difference between the fair market value of assets and their accounting or book value. This same methodology can be applied to the U.S. electric power industry. However, before we estimate stranded costs for the electric power industry let us take note of the first and most important point concerning stranded costs: Stranded costs are not stranded productive facilities. As is clearly revealed by the foregoing analysis, stranded costs are an accounting and financial issue, not a production question. Capital in place with no alternative economic use will be productively employed so long as the price received for its output is at least as large as its marginal operating cost.

2. The Magnitude of Stranded Costs: Evidence from the Financial Markets

At the end of 1994, the book value of the firms in the electric power industry was around $400 billion. This is comprised of the historical cost of physical capital net of depreciation. This is the equivalent of the $500,000 number in the example in Table 1. In the real world, book value is complicated by capital structure that includes debt and preferred stock in addition to common equity. Book value of equity in investor-owned utilities was $188 billion in 1994, long-term debt was $183 billion, and preferred stock made up the difference. At that point in time, the market value of common stock in the industry was $210 billion. The ratio of the market value of equity to its book value was 1.12:1. Unlike the example in Table 1, this says that for the investor-owned portion of the electric industry taken as a whole the difference between market value and book value is positive. This suggests that for the industry taken as a whole there are no stranded costs. On the whole, the market value of the assets in place exceeds its accounting or book value.

Table 2 reports the market to book ratios for various investor-owned utilities for 1993 through 1995. Using the most recent data, there are but seven firms with equity values less than their book values. These are Centerior Energy, Central Maine Power, Central Vermont PSC, Entergy Corp, Long Island Lighting, NY State Elec. & Gas, and Niagara Mohawk.

To reiterate the argument we presented in the context of Table 1, true stranded costs are the fair market value of a firm's assets minus their historical, depreciated book value. If the book value is greater than the fair market value, then the firm has true stranded costs. If the fair market value is greater than book value, then the firm has no true stranded costs. In the electric power industry, the book value of assets (for equity holders) is $188 billion. To determine the value of true stranded costs, we need an estimate of the value of assets in the electric power industry as they would be priced if the electric power market were fully competitive. While the current stock market valuation of equity in the electric power industry is not itself an estimate of the industry's fair market value in competition, it does contain information about that valuation and about the level of true stranded costs in the industry.

By all accounts, the financial community became keenly aware of the immediate possibility of deregulation and competitive pricing in the electric utility industry during 1994. The equity value of the investor-owned electric utility firms declined significantly in 1994. From a high in 1993 of $282 billion, the equity value of the utility portfolio fell to $212 billion at the end of 1994. The cumulative return over this period was around minus twenty-five percent, market adjusted. The ratio of market equity value to book equity value fell from 1.39:1 to 1.12:1. However, in spite of this decline in market equity, which can be reasonably related to a market perception of declining prices of electricity into the future, the market value of equity was still higher than the book value for the industry as a whole.

We have examined the stock market reaction to several news stories during this period.[7] On at least two occasions, news stories directly related to competition in electric power were met with sharp declines in the stock prices of investor-owned public utilities. These events are striking because of the near universal decline in industry stock prices in spite of the fact that these events related directly to only a couple of utilities.

During this period there were several significant event periods. Over a four day period, November 1-4, 1993, the portfolio of investor-owned electric utilities lost a cumulative 5.5 percent.[8] This period is centered on an announcement by Moody's that it had downgraded the credit rating on fifty of the top electric utilities because of the looming threat of competition. Over the month of February, 1994, the portfolio was down 4.7 percent. During this month, the Wall Street Journal carried a story

7. Event analysis uses stock market and financial data to assess the impact that investors incorporate into their perception of future events. The technique is widely used in finance and economics. For an example of the methodology, *see* Michael T. Maloney & Robert E. McCormick, *A Positive Theory of Environmental Quality Regulation*, J.LAW & ECON., Apr. 1982, at 99.

8. We used a simple market model to adjust the portfolio returns. We regressed the daily electric utility value-weighted portfolio return on the value-weighted market return over the period January 1, 1990, through May 31, 1993. The estimated portfolio beta over this period was .52. Estimates are based on data available from the Center for Research in Security Prices, University of Chicago.

describing the battle between two of California's largest utilities (SCE Corp and San Diego Gas & Electric Co.) and a number of independent power producers (IPPs).[9] Finally, in the first half of the month of May, the portfolio lost 9 percent. Much of this loss occurred simultaneously with two stories published by the Wall Street Journal. The first story, May 9, described the attempt by Las Cruces, NM, to "bypass" its utility (El Paso Electric Co) in favor of cheaper power on the wholesale market. The Journal reported this as a "test" of legality of wholesale wheeling and as "a warm up for a deregulatory trend that could easily spread across the US, bringing an onslaught of competition which could bankrupt some utilities."[10] The second story, on May 11, was a follow-up describing analysts' reports saying that electric utilities were a bad buy in the stock market because of the threat of deregulation.[11] In all, 20 points of the 25 percent decline in the equity value of the electric utility portfolio over the eighteen month period occurred contemporaneously with press reports detailing the potential threat of competition in the industry.

Throughout 1995 the stock market continued to react to news of deregulation in the industry and to economy-wide and world-wide events that implied changes in the cash flows of electric utilities. Overall, stock prices in the electric utility industry rose in 1995 by nearly as much as they fell in 1994. However, this did not occur uniformly across the industry. The stock price of some firms fell in 1995. Notably, Niagara Mohawk had an equity value decline of 25 percent in 1994 and 58 percent in 1995 for a two-year return of -68 percent. On the other hand, some firms regained in 1995 all that they had lost in 1994 and more. For instance, the Southern Company only lost four percent in 1994 and gained 21 percent in 1995. There has been substantial diversity in the stock price movements of the firms in the electric utility industry since the advent of competitive pricing initiatives. This diversity is understandable because the effects of competition will not be evenly distributed across the industry.

It is interesting to compare the electric utility industry to the market over this period. At the end of 1993, the equity value of the electric power industry was $262 billion compared to the total equity value of stocks in the United States of $5.01 trillion.[12] Electric power was 5.2 percent of total

9. Andy Pasztor, *Who Will Make Electric Power in California?*, WALL ST. J., Feb. 17, 1994, at B1.

10. Caleb Solomon, *As Competition Roils Electric Utilities, They Look to New Mexico*, WALL ST. J., May 9, 1994, at A1.

11. Warren Getler & Dave Kansas, *Stock Buys by Utility Industry Insiders May Have Been Misguided, Analysts Say*, WALL ST. J., May 11, 1994, at C1.

12. This measure of the equity value of securities in the United States economy includes stocks listed on the NYSE and AMEX and stocks traded on the NASDAQ, as reported by the Center for Research in Security Prices, University of Chicago.

equity value. By the end of 1994, equity value in electric power had slipped to $212 billion as had the market, which had fallen to $4.98 trillion. Electric power at the end of 1994 made up 4.25 percent of equity value in the U.S. economy, and the slight decline in the value of stocks from 1993 to 1994 was smaller than the decline in the equity value of the electric power industry.

Arguably, the stock market's response to the news events of deregulation is muted. In other words, the stock market is valuing the common equity of investor-owned utilities based on a chance of deregulation, but the chance is less than one. Until an event like deregulation is actually completed there is always some chance that it will change in form or be completely abandoned. The expectation of different possible outcomes has to be accounted for in the prices of the financial securities. From the perspective of the researcher or analyst, it is difficult to assess precisely the subjective probabilities employed by the financial market in arriving at the current stock price. However, there are certain principles that apply.

First, the current stock price is an estimate of the fair market value of the firm in competition, the value of any non-utility assets, and the probability of the recovery of stranded costs either by explicit payment or by delaying the move to competition.[13] In a regulated environment, the firm is allowed to collect revenues above operating costs to pay off its invested capital with an approved rate of return. Assets that are productive but fully depreciated recover only their operating costs. Under regulation, the firm's equity value should equal its book value. In a competitive regime, the fair market value of the firm depends on the cash flows produced by the firm's assets as in Table 1. Some fully depreciated assets, worth essentially nothing to stock holders in a regulated environment, are worth substantial amounts in competition because their operating costs are below the price of output. In the move to competition, the firm's equity value can be either above or below its book value depending on the net cash flows provided by its assets.

In addition, the firm's current equity value includes the possibility that in the move to competition, regulators will allow the firm something extra, something in addition to a pat on the back as the firm walks out the door into the world of competition. There is the chance that regulators will allow the firm to recover part, all, or even more than the firm's true stranded costs (where true stranded costs are the difference between the fair market value of its assets and their book value). Most observers seem to think that regulators will allow partial but not full recovery of stranded

13. As a practical matter, regulators charged with computing stranded costs using this technique should adjust the market value of equity by the fair market value of non-utility assets such as excess cash, earnings retained in land, and other holdings.

costs. In the extreme, if the financial market feels that there will be no stranded cost recovery, then the current stock price is equal to the fair market value of the firm's assets in competition. If the financial market believes that full recovery of true stranded costs but no excess recovery will occur, then the current stock price can be no larger than book value if there are true stranded costs. Finally, if the financial market feels that firms will get more than true stranded costs, then the current stock price can be larger than book even if the fair market value of the firm is less than book.

If the financial market expects that there will be a recovery of stranded costs based only on the difference between the fair market value of the assets of the utility in a competitive regime and their undepreciated book value, then the current stock price is an unbiased forecast of whether stranded costs exist. Under this assumption, stranded costs only exist if fair market value is less than book. If price is below book value, the market is predicting that the fair market value of the firm's assets in competition is worth less than book. If the financial market expects that there will be nothing more than the recovery of true stranded costs, then only firms with current market-to-book ratios less than one have any true stranded costs.

We formalize this problem as follows: Let V stand for the current market value of the firm's common equity, FMV stand for the fair market value of the equity holders' claims to the firm's assets when competition emerges, SCR stand for stranded costs recovered, TSC stand for true stranded costs, B stand for the book value of assets, and p stand for the probability of stranded costs recovery. Then

$$V = FMV + p \cdot SCR,$$

where

$$SCR = \{TSC, \ldots, B\}.$$

In words, the current market value of the firm is equal to its fair market value plus the probability of the recovery of stranded costs times the amount that will be recovered. The amount of stranded costs that will be recovered can itself vary from the minimum value of only true stranded costs up to full book value without any deduction for the fair market value of the firm's assets.

If the market is guessing that firms will get no recovery of stranded costs ($p = 0$), then the current stock price is equal to the fair market value of the assets in competition. However, it is most likely that the market thinks that these firms will get something. In fact, the market has to expect them to get something because they are getting something now. As long as regulation continues and deregulation is postponed, firms are recovering stranded costs, some excess and some true.

The fact that the market reacted so significantly to deregulation events in 1994 suggests that the market recognizes that many firms are getting paid prices in excess of long-run marginal cost. The stock price declines occasioned by the announcement of deregulation implies that the output prices enjoyed by electric utilities under regulation are higher than the output price that will be generated by a competitive market in equilibrium. That firms are currently receiving output price in excess of the anticipated competitive equilibrium price means that output price is greater than the minimum average cost of production. The conclusion is that firms are receiving stranded cost recovery now.

This is not an earth-shaking deduction. The whole notion of stranded cost recovery is based on the obvious fact that regulation is allowing firms to charge prices that do not reflect the cost of providing the product they sell to their customers. However, the subtlety of the issue is that delay in deregulation is a form of stranded cost recovery. Part of what the market impounds in the p term in our formula is the recovery of stranded costs by delay in the move to competition. Moreover, delay in deregulation provides for stranded cost recovery that is quite possibly in excess of true stranded costs. Regulation is allowing firms to receive prices in excess of cost. Some of this goes to the recovery of invested capital that has a book value greater than its fair market value, but some may simply support excess profit. To the extent that competition is postponed, utilities will continue to recover stranded costs, some of which is true stranded costs and some that may be excess.

In order to use our formula to make some projections about the magnitude of true stranded costs, we must make some assumptions. These assumptions can be grouped into scenarios about financial market beliefs regarding the probability and magnitude of stranded cost recovery. Consider the following:

1) Stranded Cost Recovery will equal True Stranded Costs

a) Probability p determined by lowest priced firm, or
b) Probability p set equal to one.

2) Stranded Cost Recovery greater than True Stranded Costs

a) SCR = Book Value of Common Equity with p determined by lowest priced firm, or
b) SCR = Book Value of Common Equity with larger p.

In the first scenario, we investigate the implication that the market is pricing utility stock based on the assumption that stranded cost recovery will be no larger than true stranded costs and that this pricing is based on the probability of the weakest firm in the industry recovering its stranded costs. The weakest firm is Niagara Mohawk, which at the end of 1995 had a market-to-book ratio of .39, the lowest in the industry. If Niagara Mohawk is expected to have no equity value in a competitive regime, that is, if it will go bankrupt without some recovery of stranded costs, then its equity value is entirely based on the possibility of the recovery of stranded costs. Its 1995 year end equity value of $983 million is based on the expectation that it will be allowed to recover some stranded costs. If its fair market value is zero, then the market to book ratio is the financial market's forecast of the probability of the recovery of stranded costs, that is, 39 percent.

If we use this as the expectation of the probability of stranded costs recovery across the industry, we can calculate the financial market's estimate of stranded costs based on the assumption that firms will not be allowed to recover more than true stranded costs. If the financial market thinks that only true stranded costs will be recovered, then only the firms with market to book ratios less than one have stranded costs. From this analysis we have stranded costs as follows: Centerior, $1.2 billion; Central Maine Power, $28 million; Central Vermont PSC, $365 million; Entergy, $321 million; Long Island Lighting, $563 million; N.Y. State E & G, $171 million; and Niagara Mohawk, $2.5 billion.[14] The total financial market estimate of stranded costs across these seven firms is $5.1 billion, and using the market to book definition of true stranded costs, none of the other firms in the industry has any stranded costs.

This is not a very big number compared to the amount of stranded costs estimated by others.[15] Maybe it is small because we have set an artificial boundary of zero on the Fair Market Value of the assets of Niagara Mohawk. Even so, it is important to recognize that if the market is anticipating recovery of stranded costs that does not exceed the value of true stranded costs, then the only firms with true stranded costs are those with market values of equity below their book values. This means that the maximum value of true stranded costs for equity holders in the electric utility industry is the sum of the book value of equity for the seven firms listed above. In our formula this is equivalent to assuming that the probability of stranded cost recovery is one. This gives a total of $21 billion, which is the sum of the book values of all firms with market-to-book ratios less than one as shown in Table 2.

Our second scenario posits that the financial market thinks that utilities will get more than true stranded costs. If utilities are allowed to get more than the book value of their assets minus the fair market value of them, then the current equity value can be larger than book value even

14. These figures are derived from Table 2.

15. *See, e.g.*, LESTER BAXTER & ERIC HIRST, OAK RIDGE NATIONAL LABORATORY, Oak Ridge, Tennessee, ESTIMATING POTENTIAL STRANDED COMMITMENTS FOR U.S. INVESTOR-OWNED ELECTRIC UTILITIES (1995).

though true stranded costs exist. For instance, if utilities are paid the full book value of their assets as stranded costs, which is around $188 billion, and if they get to keep their assets, which are still valuable in a free market, even though they have been paid off, then the current stock price will include the excessive stranded cost recovery plus the fair market value of the assets. The stock market valuation will include the fair market value of assets plus the expectation of excessive stranded cost recovery. If this is true, that is, if the financial market thinks that some firms will be able to recover more than their true stranded costs, we can still draw an estimate of the true stranded costs. It depends on the expectation of the probability of excessive stranded cost recovery and on the extent of excess.

As a first pass, let's use our original estimate of the probability of the recovery of stranded costs based on Niagara Mohawk and assume that the market thinks that, given this probability, the amount that firms recover is as large as the full book value of their assets. Our estimate, under the assumption that there will be excessive stranded cost recovery, is that true stranded costs are around $21 billion.[16] At the same time, excessive stranded cost recovery is $47 billion. Using these assumptions there are thirty-five firms that have true stranded costs. Some of the additional firms are Consolidated Edison, Northeast Utilities, Pacific Gas & Electric, and Edison International, to name a few. The additional firms with true stranded costs have market to book ratios slightly higher than one, but true stranded costs are confined to firms with market to book ratios not far from one.

As we increase the hypothesized probability of recovery of excessive stranded costs, our estimate of the value of true stranded costs increases, but so too does our estimate of excessive stranded cost recovery. So, for instance, if we set p at .61, our estimate of true stranded cost is $42 billion. At the same time, this implies an excess stranded cost recovery of $64 billion, which sums to a total stranded cost recovery of $106 billion, a number not far off from the stranded cost claims of the industry. Indeed, if we set p at .9999, the model says that true stranded costs are slightly less than $100 billion and excess stranded cost recovery is over $70 billion. In the case of excessive stranded cost recovery, p is inversely related to the probability that competition will eventually come to the industry. That is, as p goes up, competition is delayed. Our priors are that investors are expecting competition to eventually come because of the way they precipitously reacted to news events in 1993 and 1994. Even so, the financial community seems to be saying that competition is not likely to be just

16. This figure is the same as the number generated in the last scenario by coincidence only. As above, this figure can be derived from the data present in Table 2. Specifically, the market value of equity in 1995 and the book to market ratio can be used to derive the book value in 1995. The probability of stranded cost recovery assumed in this scenario is .39.

around the corner. In the final analysis, the financial market seems to be saying, in spite of the rhetoric, the true value of stranded costs is not very high while the potential for excessive stranded cost recovery is substantial.

Obviously, our stock market analysis is incomplete because the value of stranded cost recovery varies based on the choice of the value of p, the probability of stranded cost recovery. Without an independent measure of p our model can generate a wide range of numbers for true stranded costs. Even so, there is one direct conclusion: The stock market is saying that the value of true stranded costs cannot be larger than $100 billion, and if it is this high, excess stranded cost recovery will be very large.

While our stock market analysis fails to speak precisely on the question of the value of true stranded cost, we have another method at our disposal. It is the direct estimation of the fair market value of utility assets based on forecast cash flows in a competitive regime. We develop this analysis in a moment. Interestingly, cash flow analysis gives an estimated value of true stranded cost of $42 billion. Combining this estimate of true stranded costs with the stock market analysis implies that the market is predicting a .61 probability of stranded cost recovery and with it an associated $64 billion value of excessive stranded cost recovery.

DEBT AND FINANCIAL DISTRESS

It must be noted that we are not factoring long-term debt into this analysis. It may be the case that the current equity value of these firms is based on some expectation that in bankruptcy the old equity holders will not lose everything. It is true that the bankruptcy process commonly produces this result.[17] Nevertheless, historically, the returns to old equity holders going through bankruptcy have not been large. Bankruptcy value is a tiny portion of the current equity value of the electric utility industry.

It is easy to get confused about bankruptcy and financial distress. In and of itself, bankruptcy is a financial outcome. The wealth of the old equity owners is exhausted, and the debt holders usually recover less than full value. However, the physical capital and labor pool is neither destroyed nor directly affected by the financial reorganization. Later in this article we discuss several bankruptcies that have already occurred in the electricity industry. It is enlightening to forecast the effects of the possible bankruptcy of a few firms due to deregulation from the experience of the firms that have already gone through it due to other causes. The fact that the old equity holders lose substantially all of the wealth they had invested in the

17. *See* Katherine Daigle & Michael T. Maloney, *Residual Claims in Bankruptcy: An Agency Theory Explanation*, J. LAW & ECON., Apr. 1994 at 157, for a review of the law, references, and an analysis of the outcome of the bankruptcy process.

assets has no bearing on the productivity of the women, men, and machines comprising the operating unit. Whatever the inputs could do before bankruptcy, they can still do afterwards. Bankruptcy does not change the stock of human or physical capital. The few bankruptcies that may occur due to deregulation will likely allow efficient reorganizations that make for smoother operations in the future.

This is the focal point of our analysis. The debate surrounding stranded costs tends to obscure important economic issues. The assets of the electric power industry are not idled by the fact that the movement to competition makes some firms less valuable in a financial sense. Independent of the recovery of stranded costs, in a competitive market for electricity, the fair market value of productive assets will be determined by the difference between market price and production cost. If market price is larger than average production cost for an asset, then it will be employed. It will have market value, quite possibly market value in excess of its book value. But regardless of whether its fair market value is larger or smaller than its book value, it will be productively employed.

OTHER ELEMENTS OF THE STRANDED-COSTS PUZZLE

There is a second category of stranded costs. Many utilities have contracted to buy power at rates that are higher than the forecasts of prices under competition. These purchase power contracts, whether voluntary or mandatory, are analytically identical to the physical capital problem just described. The contracts mandate a minimum amount of power to be purchased at a pre-specified price. The capital value of these contracts rises and falls with the price of electricity.

For example suppose a power company has a contract to buy one million kwh of electricity per year for the next ten years from some supplier at a price of 12 cents per kwh. Let the current price of power be 12 cents. Then this contract has no economic value. The spot price of power and the long-term contract price are identical.[18] Now imagine that the spot price of electricity increases to 13 cents per kwh. Then the rights to purchase power at lower than market rates have positive capital value to the buyer. The present discounted value of the difference between the spot and contract prices times the allowed quantity over the life of the contract is the capital value of the contract.

The value of the contract becomes negative to the buyer (the electric utility) if the spot price or the expected spot price declines below the contract price. The present value of the difference between the contract

18. This simple approach ignores any option value imbedded in the long-term, fixed price contract.

price and the current price, times the required purchase volume will be the change in capital values accruing to firms with these purchase contracts outstanding. Firms with large volume purchase contracts at prices higher than anticipated under competition will sustain value losses when the price declines from its current regulated levels. This price decline is a second source of stranded costs.

It is noteworthy that the bulk of the contracts with high purchase prices and negative capital values appeared as a result of PURPA of 1978, and they are most prevalent in New York and California where public utilities were required by regulators to enter into these contracts for purchase. In the current system, utilities are allowed to charge rates that are sufficient to pay the costs of their purchased power as an operation expense. In a world of freely competitive prices, rates will become unrelated to these pre-existing long-term purchased power contracts. The negative capitalized value of these contracts can be called a stranded cost.[19]

CASH FLOW ANALYSIS OF FAIR MARKET VALUE

An alternative approach to the measurement of stranded costs is to calculate the fair market value of utility assets directly. Using this approach we estimate the net cash flows to the firms based on their costs of production and the competitive market price of electricity. In order to do this, we first look at prices and costs across companies.

Price and cost data are available for investor owned utilities from FERC Form 1 (available from the Energy Information Administration of the U.S. Department of Energy—DOE-EIA). Information on price and average operation and maintenance cost is given in Table 3 in 1994. There are 98 utilities listed in this table. These are the utilities for which we have stock market and financial information that is matched to the data collected by DOE.[20]

Even a cursory review of the data reveals that price varies widely. This is not surprising; it is because customers are paying such a wide variety of prices that there is a call for competition. The highest priced utility shown in Table 3 is Long Island Lighting. Its average revenue from all sales is 15 cents/kwh. Other New York utilities are high also. New York State Electric & Gas is the lowest of the utilities from its state at 8 cents/kwh. Other northeast utilities are also high. California is another state with utilities that charge high prices. Pacific Gas & Electric collects 10.5

19. Throughout our analysis we assume that the existing PURPA contracts perpetuate and are not violated by legislation or court rulings. We are not proposing that these contracts be nullified. We have not analyzed the details of these contracts and the firms that produce power under them.

20. Hawaiian Electric Industries is excluded because it is not interconnected.

cents/kwh; Edison International (formerly So. Calif. Edison) gets 10 cents/kwh; and Enova (formerly San Diego Gas & Electric) charges 9.4 cents/kwh.

On the other end of the distribution, there are four firms that have average revenues from all sales below 4 cents/kwh. These are at the bottom of Table 3. One is Idaho Power which has a large amount of hydro-electric production. However, two others are American Electric Power and KU Energy which are large coal-fired generators in the West Virginia-Kentucky coal fields.

Costs are also shown in Table 3 and are also distributed widely across utilities. Total production costs including production, purchased power, transmission, distribution, customer accounts, and general administration vary from 7.7 cents/kwh to 2.1 cents/kwh. As expected, given rate of return regulation, the high priced companies are also the high cost companies and vice versa. The lowest cost producer is Idaho Power. KU Energy and AEP are also down near the bottom. At the top, many of the highest priced electricity sellers have costs in excess of 6 cents/kwh.

Even though there is a strong correlation between price and cost, the allocation of cost across categories is revealing. Price is strongly correlated with the average cost of total production. The simple correlation coefficient is .83. It is also strongly correlated with fuel cost from steam generation presumably because of fuel adjustment clauses. Even so, price is not significantly related to the average total production costs of conventional steam generation nor the average production costs of nuclear generation. That is, at the production level, there is not the strong link between cost and price that we see at the aggregated level. This makes sense when we think about the process of rate regulation. Regulators allow for revenues to be set high enough to cover operating costs plus a recovery of investment. Prices vary across companies based on the extent to which their facilities are depreciated. Variation in the extent of depreciation breaks the correlation between operating costs and price.

Note that 92 out of the 98 investor-owned utilities in Table 3 have average operating and maintenance cost for their steam generating facilities that is less than 4 cents/kwh. Of course, average cost is based on current production levels, and current production is characterized by a lot of down time and idled capacity.

The major conclusion that we developed in earlier work is that competition will cause price to fall because it will allow firms to expand production of underutilized facilities and sell this power by discounting its price.[21] The extent of output expansion depends on expansion of production, which in turn depends on capacity utilization. We assume that

21. *See* MALONEY, *et. al., supra* note 1.

output will be able to expand by the amount of extra generation available from running existing conventional steam generation full time. For each utility we compute extra generation by calculating how much more steam generation it could achieve if its capacity utilization went up to the capacity utilization level reported by NERC for steam generators when they are running. In our earlier work we estimated the potential expansion of the system using NERC data and found that capacity utilization for conventional steam facilities could increase from its current level of around 52 percent to 71.6 percent by running them during what are now their idle or reserve hours.[22] Currently, generation facilities are simply idled during times of insufficient demand. Competition will induce firms to keep generators running during this time and to sell the power at whatever price it will fetch. Our estimate of that price is 5.12 cents/kwh on average across customer classes and regions of the country.

Data from DOE-EIA Forms 860 and 759 give a picture of capacity utilization. Table 4 shows the capacity utilization rates and electricity production levels across the utilities for 1994. The mean capacity utilization rate is 53.9 percent, the median is 55.7, with a standard deviation of 17.5. Capacity utilization ranges from 96.3 to 5.8 percent. The data on production show that there are utilities that currently exceed the average full-capacity utilization mark of 71.6 percent.

Under our short-run competitive production scenario, electricity production will expand to the point of full capacity utilization. We estimate this output expansion by assuming that each utility will run its conventional steam generating facilities full time and that this means these facilities will operate 71.6 percent of the time, on average. Based on the current capacity utilization at each utility, increasing production to 71.6 percent capacity utilization implies an increase in production from these investor-owned utilities of 26.1 percent. For those utilities that are currently operating in excess of 71.6 percent, we assume no additional output. The fact that some utilities are able to achieve capacity utilization rates in excess of 71.6 percent means that there is some possibility that the entire system can be operated at efficiency levels in excess of our forecast of full capacity utilization.

Increased capacity utilization should lower average operating and maintenance costs. Part of this increased efficiency comes from the fact that increased capacity utilization lowers average fuel costs. Running a plant full time increases the effective heat rates that can be achieved. Also, maintenance per unit of output is cheaper.[23] Fixed cost components of maintenance get spread over more units.

22. *Id.* Vol. I at 25.

23. Recall that we have already factored into our computations of output expansion the additional maintenance time required when plants run longer.

We estimate the expected cash flow for each utility based on its production capacity and costs based on the forecasted price in the competitive regime. We use a modified version of the Law of One Price. We assume that the market price of electricity will be no higher than 5.12 cents/kwh. However, for those utilities that are currently charging less than this, price will not increase. We assume that utilities that have excess capacity that must be put onto the wholesale grid will receive 3 cents/kwh for this generation. The details of our cost estimation is shown in an appendix to this paper.

Based on our cash flow analysis, the estimated total value of true stranded costs is $42 billion. This is shown in Table 5. Thirty eight firms have stranded costs. The range runs from $12 billion for Pacific Gas and Electric to $2 million for Northwestern Public Service Co.

There are three notable anomalies in Table 5. First, based on our net cash flow analysis, Niagara Mohawk has no stranded costs. In part, this is probably due to the fact that we have not perfectly accounted for the PURPA contracts this firm holds. However, this does not explain everything. As we reexamine the financial profile of Niagara Mohawk we find that it is relatively high cost in general and has high overhead costs. One is left with the suspicion that the current financial plight of this firm is due largely to its inability to control expenses. As a stranded cost question in a freely competitive market for electric generation services, one envisions the generation facilities of Niagara Mohawk being spun off for whatever they will fetch. The proceeds of these sales would be deducted from the book value of remaining assets. By our calculation, the asset sales would cancel out the book value leaving no stranded costs. Our estimates suggest that Niagara Mohawk's generation facilities can yield more cash flow to new investors than they are currently producing in the existing enterprise.

The second anomaly on the list is Entergy. By our calculations, Entergy should be a big money-maker in the competitive picture. However, the stock market does not currently see the firm in this light. More detailed analysis is required.

The last anomaly in the stranded cost list is Idaho Power. Our estimates indicate that Idaho Power has stranded costs of $300 million. The reason that this is an anomaly is because Idaho Power is the second lowest priced utility in the country and has no excess capacity in conventional steam generation facilities. In other words, Idaho Power is predicted to be almost completely unaffected by deregulation and yet it is predicted to have stranded costs. As a cross check on our methodology, we found that our estimate of net cash flows only differed from the actual 1994 cash flows for Idaho Power by a small amount. This difference was the result of a slight difference in the tax rate it paid and because of some special income items. These did not amount to much. In fact, based explicitly on 1994 net cash flow, the discounted presented value of those cash flows is less than the book value of the company. The implication is that regulators in Idaho are tough or that some other non-regulatory extraordinary event is currently affecting investor expectations about Idaho.

For the rest of the firms in the sample, the direct estimate of fair market value of utility assets yields a forecast value of true stranded costs that is very similar to the numbers that we get from other measures at least on a utility by utility comparison. Over the sample of investor-owned utilities, we find that firms currently charging relatively high prices will be left with some stranded costs in a fully competitive environment. On the other hand, firms with excess base-load capacity will potentially profit from competition. The current stock market valuation of all the investor-owned utilities gives a muted picture of this, reflecting the fact that the financial community expects that deregulation will be delayed or altered by the political process. Indeed when we compare the stock market analysis to the cash flow measurement of stranded costs, we reach the conclusion, as noted above, that financial investors are forecasting that there will be substantial excess stranded cost recovery.

3. A Brief History of Electricity Producers in Financial Difficulty

Some utilities that have disproportionately large stranded costs may be forced into bankruptcy if prices in their markets were to fall to competitive levels. Will the financial difficulties of these utilities preclude the delivery of reliable electricity? Our review of the past experiences of financial distress in this industry lead us to answer this question in the negative. The fact that insolvent utilities remained viable producers of electricity both during and after financial restructuring suggests that electricity customers will not be harmed by any wealth losses visited upon utility investors.

Some perspective on this question can be gained by examining the history of reliability and financial distress. NERC has reported no problems in reliability in the past two decades. Yet over the same time, a handful of utilities have undergone extended periods of financial distress. Most of these difficulties are related to investments in nuclear power.[24]

UTILITIES IN DISTRESS

The most notable recent example of financial distress is Public Service Company of New Hampshire (PSNH). PSNH was the lead partner

---

24. An enlightening introduction is found in Ron Winslow, *Utility Chapter 11 Filing May Mean Problems for Consumers, Investors*, WALL ST J., Apr. 17, 1984, at 37. The story starts, "No electric utility has declared bankruptcy in years—not since the Depression in fact."

in the construction of the Seabrook Nuclear Power Generator.[25] Seabrook was a troubled project from the beginning, which can be marked as the application for a construction permit in early 1972. Permits and plans were repeatedly delayed, approved, suspended, and reinstated during the mid-1970s; ground was finally broken in August, 1976. Nevertheless, groups opposed to the plant or various aspects of it continued to win court injunctions and stays that had negative implications for the financial viability of the project. Financing difficulties halted construction of the first reactor in 1984 and caused a second to be canceled. The initial expected cost of Seabrook was $1.0 billion; by the time it was completed in 1989, the total was $6.3 billion. Forbes magazine referred to Seabrook as "the largest managerial disaster in business history."[26]

The expense, coupled with the protracted delay in revenue from power generation produced a river of red ink for PSNH and its partners. Numerous maneuverings in 1979, including an emergency rate increase, sales of stock, and rearranging of credit lines signaled trouble. That PSNH might be forced into bankruptcy was openly discussed at least as early as 1982. In 1984, additional moves including the omission of dividends and conversion of missed payments to loans forestalled formal bankruptcy proceedings temporarily. PSNH filed for bankruptcy in January of 1988, the first investor-owned utility to do so since the 1930s.[27] It did not emerge from bankruptcy until May of 1991, under a plan which involved a subsequent merger with Northeast Utilities.[28] The merger was finally completed in June, 1992. The period of financial distress for PSNH lasted over a decade. In spite of this, there was no idling of any productive facilities of PSNH.

A second utility, El Paso Electric (EPE), filed for bankruptcy in January, 1992.[29] EPE's troubles stemmed from its 15.8 percent share of the Palo Verde Nuclear project. Signs of financial trouble began in 1986 when Standard & Poor's lowered its debt rating. In 1987, EPE requested a 33 percent rate increase, and Standard and Poor's lowered the rating again. EPE sold its stake in Palo Verde for $250 million in 1988 in a lease-back arrangement, suspended the common stock dividend in 1989, reported its first loss of $105.8 million and sold additional assets in 1990. By January of 1992, EPE was not expected to avoid bankruptcy. It had survived because

25. This account of the Seabrook story is taken from HENRY F. BEDFORD, SEABROOK STATION: CITIZEN POLITICS AND NUCLEAR POWER (1990).

26. *Id.* at 30.

27. Lawrence Ingrassia & Christopher J. Chipello, *PS New Hampshire Files Bankruptcy Plea*, WALL ST. J., Jan. 29, 1988, at A2.

28. *Public Service of New Hampshire*, WALL ST. J., May 17, 1991, at C8.

29. Ann de Rouffignac, *El Paso Feels Pressure to Reorganize Amid Prospects of Bankruptcy Filing*, WALL ST. J., Jan. 6, 1992, at B4; Ann de Rouffignac, *El Paso Electric, Reeling with Debt, Files Chapter 11*, WALL ST. J., Jan. 9, 1992, at A5.

its creditors granted "extension and waivers." Two serious merger proposals ultimately failed, and the reorganized company emerged from bankruptcy protection in February 1996. Again, from the production side, bankruptcy did not cause any power plant to be idled.

A third case is Long Island Lighting Co. (LICLO). LILCO's financial troubles stemmed from its investment in Shoreham, a nuclear plant that was built and decommissioned without producing a flicker of power. In 1983, Standard and Poor's downgraded all of LILCO's debt, much of it to speculative rank.[30] Layoffs, salary cuts, and dividend cuts were implemented in its battle to survive the costs from Shoreham. The utility appeared to be on the verge of bankruptcy several times in 1983 and was rescued by extension of default deadlines by major lenders and an annual rate increase of $245 million that the Public Service Commission explicitly stated would enable the utility to obtain bank financing it needed to stay solvent.

Dividends on common stock were not restored until September 1989.[31] In 1989 LILCO was poised to obtain a license to begin production at Shoreham when it agreed to decommission the plant in exchange for billions of dollars in rate increases.[32] The rate hikes granted in the interest of keeping LILCO solvent forced its customers to pay the highest electricity rates in the country. Residential customers paid 16.8 cents per kwh in 1994, roughly twice the national average and 50 percent above those in the New Jersey and Connecticut suburbs of New York.[33] LILCO survives in its current form only because its customers who are searching for ways to purchase from alternative sources have been saddled with billions of dollars in Shoreham expenses.

The infamous 1979 Three Mile Island accident created substantial financial distress for its owner General Public Utilities. GPU faced massive losses as a result of the disaster. Clean up costs alone were projected to be enormous. Yet the most immediate problem stemmed from the loss of two revenue producing assets-the damaged reactor and an undamaged reactor (unit #1 which did not return to production until management issues were resolved in October 1985). Immediately following the accident, the firm sought $450 million in bank credit to avoid bankruptcy.[34] Shortly thereafter a cooling system problem at the Oyster Creek Nuclear Station shut this plant down for the month of May. Yet the lights stayed on. The firm drew

30. *S.&P. Lowers Lilco's Rating Again*, N. Y. TIMES, May 24, 1983, at D6.

31. *Lilco Declares 25 Cent Dividend on Common Stock*, WALL ST. J., Aug. 15, 1989, at C18.

32. *New York Regulators Clear Accord on Shoreham*, Rates, WALL ST. J., Apr. 6, 1989, at A9.

33. Charles M. Studness, *LILCO: The Politics of High Electric Rates*, PUBLIC UTILITIES FORTNIGHTLY, Sept. 1, 1995, at 42.

34. John R. Emshwiller, *GPU Seeks $450 Million in Bank Credit to Pay for Accident, Avoid Bankruptcy*, WALL ST. J., May 3, 1979, at 2.

additional power from its other generating facilities and negotiated contracts to purchase electricity with Philadelphia Electric, Pennsylvania Power and Light, and Ontario Hydro. To solve its financial hemorrhage, GPU turned repeatedly in the following years to the utility commissions of New Jersey and Pennsylvania for rate increases, approval to pledge accounts receivable as collateral for bank loans, and other emergency measures.[35] Stock dividends were eliminated and did not resume until April 1987.[36]

Tucson Electric Power Co's (TEP) troubles stemmed from a "stream of misdirected investments" in ventures unrelated to electricity. [37] A new CEO in 1985 began an acquisition binge in auto financing, venture capital, real estate, and investments in thrift institutions that by the end of 1988 had swollen to nearly 40 percent of the company's assets. The possibility that bankruptcy protection would be sought was raised in May of 1990.[38] Auditors claimed the company could not stay afloat in April of the following year, and creditors attempted to force Chapter 11 proceedings in July. Financial restructuring was ultimately completed in December of 1992, although losses continued to plague the company in 1993 and 1994.[39]

Finally we have the default of a publicly-owned utility. The Washington Public Power Supply System (WPPSS) was organized in 1957 for the purpose of developing electric power generating facilities.[40] WPPSS originally consisted of 17 municipal electric utilities. WPPSS and the Bonneville Power Administration (BPA) made ambitious plans to develop as many as twenty nuclear power plants to serve the Pacific Northwest region. The first project, begun in 1971, was to build three plants at an expected cost of $1.6 billion; these costs were to be shared by 105 municipal

---

35. *Pennsylvania P&L, GPU Set Price Accord On Electricity Supply*, WALL ST. J., June 6, 1979 at 12; *GPU Agrees to Buy Some Electric Power from Canada Firm*, WALL ST. J., July 10, 1979 at 4; *GPU Unit Seeks Annual Rate Rise of $113 Million*, WALL ST. J., May 7, 1979, at 2; *Jersey Central P&L Is Granted $70 Million Annual Rate Boost*, WALL ST. J., Sept. 7, 1979 at 2; *GPU Unit is Told to show Why Its License In Pennsylvania Shouldn't Be Rescinded*, WALL ST. J., Nov. 2, 1979 at 12; *GPU Utility Granted Interim Rate Increase by Pennsylvania PUC*, WALL ST. J., Feb. 11, 1980 at 38; *General Public Utilities Says Two Units Plan To File for Rate Boosts*, WALL ST. J., Mar. 3, 1980 at 14; *GPU Unit Granted $34.2 Million Boost in New Jersey Rates*, WALL ST. J., Apr. 2, 1980 at 5.

36. *General Public Utilities Sets Its First Payout on Common Since '79*, WALL ST. J., Apr. 3, 1987 at 39

37. Frederick Rose, *Troubles Beset Utility After Its Chief Makes An Abrupt Departure*, WALL ST. J., Aug. 22, 1989 at A1.

38. *Tucson Electric Co. Might Have to Seek Bankruptcy-Law Aid*, WALL ST. J., May 17, 1990 at B9.

39. *Restructuring Plan Gets Approval of Shareholders*, WALL ST. J., Nov. 18, 1992 at A4; Rhonda L. Rundle, *Tucson Electric Completes Revamp, Averting Bankruptcy-Law Protection*, WALL ST. J.,. Dec. 16, 1992 at A4.

40. *See* JAMES LEIGLAND & ROBERT LAMB, WPP$$: WHO IS TO BLAME FOR THE WPPSS DISASTER (1986).

utilities and five private utilities involved as partners. In 1976 most of these same utilities combined to build two additional plants. This was somewhat out of step with national trends. By 1974, dozens of nuclear projects outside of the Pacific Northwest had been canceled, and a greater number were being delayed.

In 1981, a review by the budget director projected the total cost of the project to be $23.8 billion. Work on the second batch of plants was terminated. Eventually, two of the three original plants were mothballed; only one plant was ultimately completed. Court rulings invalidated the contracts signed by some of the municipal utilities to finance the second batch of plants. As a result, WPPSS defaulted on $2.25 billion of debt in July of 1983, the largest municipal default in the nation's history. Litigation over this default continued into the 1990s. Even so, it does not seem to have had led to a significant decline in the flow of capital to public enterprises.

IMPLICATIONS FOR DEREGULATION AND STRANDED COST RECOVERY

The cases discussed above are noteworthy but not unique. Financial conditions deteriorated across the board for utilities during this period. In 1970, S&P's bond ratings were AA or AAA for 80 percent of the electric utilities. By 1981, there were none with AAA ratings and just 25 percent had a rating of AA. The idea that utilities represent the safest return is no longer credible.

Typically, these troubles trace to investment in nuclear power plants. Investors lost big sums; electricity consumers lost even more. When in financial difficulty, utilities with nuclear investments repeatedly requested and received rate increases from the state public utility commissions. It is important to recognize that the rate increases preserved the principal of bond holders and not the existing physical assets of producers. To the extent that these increases protected future investment in generating capacity, the consumers may have been particularly ill-served.[41] The result of these decisions is a checkerboard pattern of electricity rates (New York, its neighbors, and the state of New Mexico are prime examples) whose only rationale is that one utility district made a nuclear investment and its neighbor did not.

Our review of the evidence finds not a single mention of reliability problems related to these firms. This should be no surprise. Theory suggests

41. Even before the massive cost overruns had taken place, the finance director of the Public Utility Commission in New Hampshire found that the generating capacity (PSNH) proposed for Seabrook was not needed and would unnecessarily raise the electricity bills of New Hampshire consumers.

that they would continue to produce electricity because the net revenues from continued operation are enormous. The ability to generate electricity is a producer's greatest asset and its most direct remedy for a shortfall in cash flow.

The stranded cost question may be in large part an issue of a series of imprudent nuclear power plant investments. The few, high-rate utilities that will be hurt by competition typically have big nuclear investments, some of which are not producing electricity. In general, nuclear power plants are efficient producers of electricity. However, in several isolated but notorious cases, where the timing of investment was bad and where construction delays added to capital costs, nuclear plants will never recover their original costs except by regulatory fiat or some other transfer of money from consumers or taxpayers. Denial of stranded costs would do much of what bankruptcy did in these cases (or in the case of LILCO, could have done), but history suggests that it would not shut off the power or reduce the willingness or capacity of the industry to invest prudently in the future.

The preceding cases suggest that bankruptcy, while a nightmare for equity investors and bond holders, seems to have had virtually no impact on the production and delivery of electricity. The lesson we draw from this is that any financial difficulties created by deregulation are likely to be absorbed by the industry in the same manner. The chief difference is that rate increases paid by consumers to high cost firms will be replaced by capital losses incurred by those firms' investors.

4. Efficiency Rationales Advanced By Proponents of Stranded Cost Recovery

Our analysis to this point indicates that, while stranded costs may have important financial consequences for a select group of utilities, both theory and history suggests that the impact on the production of electricity will be negligible. We are left with the question, Why is so much made of stranded costs in the case of electric utilities? Proponents of recovery base their case on two issues: the existence of a regulatory compact and the cost of capital.

THE REGULATORY COMPACT THEORY

Baumol and Sidak, among others, have recently proposed the regulatory compact theory, which argues that a compact or implicit contract was created by the public regulation of utilities.[42] The compact is one in which electric utilities agreed to sell their output at prices determined by government regulators. They also agreed to sell the desired demand for

---

42. BAUMOL & SIDAK, *supra* note 2.

power at the regulated prices, and they agreed to supply power in their designated service area to all buyers in that market regardless of the cost of connection and service. In exchange, the utilities were granted freedom from competition, the right to recover their variable costs, and the right to make a "fair-rate-of-return" on their prudent investments. Proponents of the compact theory of regulation assert that electric utilities should be allowed to recover their stranded costs; otherwise the state has reneged on its part of the bargain.

The state should live up to its obligations. But the regulatory compact theory has blinders on: the fundamental problem is that there also exists a compact between citizens and their government. All citizens, not just the owners of electric utility stocks and bonds have a compact with their government. This latter view suggests that a compact between electric utilities and government is not special or deserving. Furthermore, any such compact is a two-way deal. Producers and consumers were supposed to get competitive prices as part of the bargain.

Whether a one-way compact with electric utility investors ever existed is a matter of individual opinion. We simply note that if the compact theory applies, then the debt of public utilities should have the same risk level as government bonds. If, as asserted, the one-way compact theory implies producers have a right to stranded cost recovery, then government cannot take action that decreases the net revenue stream required to maintain the approved rate of return. Even a superficial analysis of bond prices and yields reveals that electric utility debt has a higher return, implying higher risk, than comparable, risk-free government securities. This implies that the holders of this debt believe that there is at least some chance that any one-way compact between government and regulated firms is not inviolate.

Table 6 shows the yields to electric utility and government bonds for the period 1985-1990. Note that the electric utility yield is always higher, implying greater risk. The difference should average zero under the compact theory of regulation, but it does not. Further, the risk premium varies in standard ways. Two groups of researchers analyzed the response of the financial markets to the Three Mile Island accident. Barrett, et al., find that the risk premium in utility bonds increased 20 to 30 basis points following the accident.[43] Bowen, et al., conclude from stock market movements that "Investors appear to believe that losses to utilities committed to nuclear energy will not be fully compensated for [.]" as a

43. W. Brian Barrett, et al., *The Effect of Three Mile Island on Utility Bond Risk Premia: A Note*, J. OF FIN., at 255 (1986).

result of the Three Mile Island accident.[44]

The existence of this risk premium for electric utility bonds shrouds the compact theory in darkness. While there may have been a conceptual understanding between regulators and utilities, financial investors did not view the deal as risk free. And well they shouldn't, as the evidence of suspended dividends and default in the previous section attests. If there is a one-way regulatory compact, why have bond-holders of the Washington Public Power Supply System failed to recover the full value of their financial investment stranded by the default of these securities? History provides little evidence to support the claim that the compact theory implies recovery of stranded costs.

THE COST OF CAPITAL JUSTIFICATION FOR STRANDED COST RECOVERY

As we have pointed out in a number of contexts, stranded costs cannot, by themselves, idle or render unusable any facility. However, some analysts have advanced the proposition that stranded cost recovery will have implications for the allocation of capital to the electric utility industry. In particular, they argue that the denial of stranded cost recovery will lead to a downgrading in bond ratings. According to this argument, the lower quality bonds raise the cost of capital to the industry, and this is bad. This line of argument is misleading.

First, the costs involved are sunk; their recovery is primarily an issue of wealth distribution, not resource allocation. Deregulation itself, regardless of the issue of stranded cost recovery, may well increase the cost of capital. But there is every presumption that this is efficient and will improve the allocation of capital to the economy as a whole. To the extent that capital investment decisions in this industry have been based solely on the portion of risk borne by investors, capital costs have been artificially low. The end result has been excessive investment in capital in this industry. Shifting the risk of capital onto the shoulders of producers addresses this problem.[45]

With regulation and revenue recovery, the risk of changes in capital values is borne by electric utility consumers. With competition, this risk shifts to capital owners. The simple shifting of risk does not increase its magnitude or jeopardize the production and consumption in the industry. It simply redistributes the risk to different parties. Moreover, firms with the

---

44. Robert M. Bowen, et al., *Intra-Industry Effects of the Accident at Three Mile Island*, J. OF FIN. & QUANTITATIVE. ANALYSIS, at 106 (1986).

45. As discussed below, producers can voluntarily contract with buyers to share this risk by a long-term contracting relation in an unregulated environment.

ability to manage and diversify risk via the share holding of their owners are far and away more efficient risk bearers than consumers of the product. On both counts, the economy is better off because efficiency is enhanced.

Consider also that deregulation is likely to substantially alter the means of marginal capital expansion. If additional capital in the industry is provided by relatively small, relatively efficient gas turbine generators and if much of this generating capacity is owned by industrial users that provide power to the electricity transmission grid in conjunction with meeting their own thermal and electricity energy needs, the riskiness of marginal capital investment in the electric power production is not identical to the riskiness of the currently invested capital.

EFFICIENT BEARING OF RISK

At any moment in time there is uncertainty about the future value of electricity to consumers. The consumption value of electricity can rise or fall as progress unfolds and invention changes the structure of relative prices. That risk can be distributed across a wide variety and classes of individuals. In the simplest case, the seller of the product bears all the risk of price and cost changes. Customers come and go as the price varies. In more complicated scenarios, sellers can arrange long-term contracts with buyers that shift some of the uncertainty to the purchasers. In the case of electricity, since sellers are allowed to recover all of their prudent costs, a significant portion of price and cost variability has historically been placed on the shoulders of consumers. Shifting this risk back to producers does not, by itself, change the underlying structure of uncertainty.

There is, however, a positive benefit of shifting the risk to producers, since the production side of the market is better equipped to manage risk. Clearly, electric utility investors can diversify their financial holdings across a broad spectrum of assets and thereby eliminate any systematic risk unique to electricity production.[46] In addition, producers are in better position to anticipate and manage inherent risk than consumers. In order to deal efficiently with fluctuating electricity prices, consumers would have to individually arrange for alternative fuels for heating, lighting, and the like, or purchase the proper financial portfolio. By virtue of their relatively small purchase volumes, the diversification options for consumers are relatively costly. The shifting of risk from producers to

46. It bears noting that institutional investors are substantial owners of most public utility stock. For instance, 38.2% of all Duke Power common shares are held by institutions. On average, across the entire portfolio of publicly traded utilities, 31.3% of all common shares outstanding are held by institutions.

consumers inherent in the current regulatory regime is one of its pathological features, not something to be preserved.

5. On the Efficient Recovery of Stranded Costs

In the previous four sections we have argued that the recovery of stranded costs will have no impact on the deployment and allocation of capital. Whether a firm recovers its stranded costs or not has no impact on its decisions as to what types of fuel to use, how much output to produce, what price to charge, what types of new investments to make, the appropriate level of maintenance, or any other operating characteristic. Recovery of stranded costs will enrich stock and bond holders at the expense of consumers and taxpayers. As long as stranded costs are recovered efficiently, the question is purely one of wealth redistribution.

UNIT CHARGES ARE INEFFICIENT

The essential requirement for efficient recovery is that charges be designed so that they avoid any impact on marginal decisions. In short, the efficient method of transferring funds from electric utility consumers to producers is with a fixed charge or access fee. Consider the graph represented in Figure 1. The demand for electricity and the marginal cost of producing power are shown.[47] Under competition, the price of power will be P_c. At that price, consumers will buy q_c units of power per period.

Now suppose that regulations are put in place so that under competition producers are allowed to recover some or all of their stranded costs via a unit increment of tax on power. Let this unit recovery charge be r. The price of electricity will rise to P_r, and the consumption will decline to q_r. Note that the price of electricity will rise by the amount of the recovery charge if the marginal cost of supplying electricity is constant over the relevant range of output. In the diagram, the new, net-of-recovery charge payment to utilities for power falls from P_c to C_r (because marginal cost is rising and less total output is being produced). Those utilities that do not recover any of their stranded costs will see a lower market price for electricity. This will idle the facilities with the highest marginal costs of production, and as the graph confirms, total output will decline.

The utilities will receive an extra r^*q_r of revenue which will be called the stranded cost recovery. Some of this is just a transfer of consumer surplus to utilities that will have no ill economic effects. However, as the graph reveals, there is a dead-weight loss to the economy engendered by

47. We have obviously abstracted from the various classes of users for the sake of simplicity here.

the unit price recovery method.[48] This dead-weight loss is the shaded area, abc, in the figure. A portion of this triangle is lost consumer surplus and a portion is lost producer profit. The lost triangle is the inefficiency created by recovery of stranded costs based on a unit charge. The inefficiency does not arise from the fact that consumer surplus is transferred to producers. The inefficiency is created because the marginal value of power exceeds its marginal cost of production. Imposing regulation that stipulates that stranded costs are to be recovered by a per-unit fee, r, drives a wedge between the value of power to consumers and its cost of production at the margin. A potential gain from trade is denied.

The worst example of the per unit fee would be for regulators to tack the recovery fee onto transmission rates. High (stranded) cost utilities would like nothing better than for transmission rates to soak up the difference between low cost producers and the current regulated prices in their market. But there are *no* stranded costs in transmission, and bundling these two activities creates an inefficient cross subsidy.[49]

AVOIDING THE DEAD-WEIGHT LOSS

There is a simple way to avoid the dead-weight loss of stranded costs recovery which still allows for recovery. The efficient system uses access or lump-sum fees to transfer funds between consumers and producers. In effect, the price of electricity has two components. One component, the access charge, is for the use of the system. This charge does not depend on the amount of electricity purchased by any consumer. The other component is the unit charge. It bears noting that the move to competition in long distance telephony has created this two-part scheme. Each telephone user pays a network access fee and then pays per minute charge for the long-distance calls. The access fee bears no relation to number or duration of long-distance calls.

Figure 2 demonstrates the relative efficiency of two-part prices over unit-cost recovery. Again under competition and no recovery of stranded costs, the price of electricity will be P_c and consumption will be q_c. Suppose there are n homogeneous consumers who create the demand for power. Then suppose that R is the amount of stranded costs that regulators have mandated that utilities be allowed to recover. The efficiency access fee is R/n per period per customer. Note that this has no impact on the unit price

48. Rent seeking costs are also relevant here, but it appears that these will be incurred regardless of whether recovery is imposed or not. If there were no question that recovery would be denied then these costs would be minimized.

49. The court said in Cajun Electric Co-op Inc. v. F.E.R.C., 28 F.3d 173 (D.C. Cir. 1994), that imposing generation cost on transmission fees is an illegal tying arrangement under antitrust law.

of electricity. Assuming that there are no income effects in demand generated by this access fee, then demand is unaltered. Some analysts have suggested that this two-part access fee will reduce the number of customers. This need not be the case. Each consumer who was previously purchasing power continues to purchase the same amount prior to the access charge. This two-part price allows for the transfer of funds from consumers to producers without affecting the market equilibrium. No doubt, the wealth of consumers is lower, but the wealth of producers is higher by an exact offset. This is just a transfer with no impact on operational efficiency, economic welfare, or gross national product. It simply is a transfer of wealth with no other consequences.[50]

Exit Fees

It has been proposed that utilities be allowed to charge "exit" fees when they lose their customers to rivals. Exit fees are an inefficient means of transferring income to utilities. If Firm A has a customer who wishes to do business with Firm B, but the exit fee prevents the change, then the customer and the economy is stuck with the higher cost producer, A, in lieu of the lower cost seller, B.

Some analysts have incorrectly argued that exit fees are efficient on the grounds that Firm A has lower operating costs than B but higher fixed costs of operation due to some circumstance. Suppose costs are as just described. The error in this argument is the assumption that fixed costs will cause firm A to lose customers to Firm B. It is the marginal costs of operating that determine price, at least in the short run. The higher non-marginal operating costs will not raise the price offered by Firm A when bidding for business. Even if the lower marginal cost firm, A, was forced to bankruptcy by its fixed obligations, its operating capital would reemerge, reorganized under new ownership. The financial reorganization would not alter Firm A's inherent operating cost advantage.

50. An alternative to two-part tariffs is to use the general taxing authority of the state to provide the lost wealth. In other words, states could levy an income tax and pay these proceeds to the electric utilities to cover their lost income from lower electric prices. Of course, most any observer would say that this is politically unlikely. Therein lies the point. A two-part tariff is nothing more than a consumption tax on electricity consumers. Neither a tax on electric consumers or a general tax has any operational implications for the electric power industry. Why one might be considered unlikely and the other a real prospect is an intriguing question. Given that almost all income-tax payers are also electricity consumers, the distinction is economically vacuous. The fact that a tax and subsidy scheme smacks of corporate welfare does not change the color of the horse.

Partial Recovery of Stranded Costs

There are proposals to allow some, but not all of stranded costs to be transferred to producers. As long as this recovery is not based on unit price increases or transmission cost increases, there is no reduction in the net welfare gains from competition. Any stranded cost recovery based on access fees reduces consumer welfare by the amount of the stranded cost recovery but has no effect on net welfare.

6. CONCLUSION

This paper uses standard economic methods to assess the implications of stranded cost recovery in the process of deregulating electric utilities. Economic theory implies that stranded cost recovery is primarily an issue of wealth redistribution, with little or no impact on the utilization or allocation of capital. The history of utilities in financial difficulty buttresses this conclusion—production and distribution of electricity continues unabated in the midst of financial reorganization.

The financial markets provide evidence on the potential magnitude of stranded costs in this industry. This source of information suggests that the size of these costs is much smaller than proponents of recovery have argued. Further, the distribution of stranded costs varies significantly from one utility to the next; among utilities there will be both winners and losers from deregulation, which is no surprise.

The efficiency rationales advanced by proponents of recovery do not bear close scrutiny. The compact theory has been used to imply that government has guaranteed utilities a revenue stream sufficient to cover all costs. The corollary to this proposition, that the yields on utility and government debt are identical is clearly inconsistent with the facts. Denial of stranded cost recovery thus does not violate a compact, and does not threaten capital investment with the prospect of future "takings." To the extent that the cost of capital is altered by deregulation, there is every presumption that this will improve the economy-wide allocation of capital in the future.

Historically, electric utilities have petitioned the government for revenues which cover their costs and provide a return to their investors. The petition to recover stranded costs continues an age-old tradition between the utilities and regulatory agencies. There is little in this tradition to give confidence that stranded cost recovery will proceed in an efficient manner, and every reason to believe that it will prolong the realization of the gains from deregulation of the markets for electricity.

APPENDIX

Using data that we have from the various DOE databases we estimate average cost as a function of capacity utilization and then derive the value of marginal cost. From these estimates of average and marginal cost, we estimate the potential cash flows that firms will enjoy in a competitive electricity market. Based on the cash flows, we derive the fair market value of their utility assets and then calculate the value of true stranded costs.

We estimate an overall operation and maintenance average cost

$$AC=\beta_0+\beta_1 F_1+\beta_2\left[\frac{1-U}{U}\right]^{1+\beta_3}$$

function using an iterative maximum likelihood technique based on the following cost function specification:

where AC is total operation and maintenance cost for conventional steam generating facilities divided by output from these facilities, U is capacity utilization at these facilities, and F is the average cost of fuel. Including fuel cost in the regression is a way of accounting for the fact that some generating facilities are located in areas where transportation cost of fuel significantly increases its cost. Holding the one component of cost constant, we estimate the effect on cost of changes in capacity utilization.

We estimate this equation using 92 observations available for investor-owned utilities with conventional steam generating facilities. We exclude observations for those utilities that have capacity utilization rates below 20 percent. The estimation results in a good fit. R^2 is .86, which says that the model explains over four-fifths of the variation in average cost. The standard error of the residual is .25 cents/kwh. The following parameter values are obtained: $\beta_0 = 1$; $\beta_1 = 1$; $\beta_2 = 1$. The model specification we employ assumes that average cost falls continuously, but this assumption is consistent with the observed value of average cost across the range of the data. Of course, there is variation across utilities that we are not capturing in this model. We include the age of the generating facilities in the estimated function, but it is not related to cost. This is consistent with the information we have received from plant engineers and electric power consultants concerning the operation and maintenance of conventional steam generating facilities.

Using our cost function estimate, we forecast average cost at the point of full capacity utilization, which we conservatively assume to be 71.6 percent. We also derive the value of marginal cost at this point. Over the 98 firms in the table, the mean current average cost is 2.49 cents/kwh. Average cost is forecast to fall to 2.26 cents/kwh for these firms when the industry moves to full capacity utilization.[51] Finally, marginal cost at the point of full capacity utilization will be around 2.16 cents/kwh. There is only one value above 4 cents/kwh. This is for Central Vermont Public Service Corp., which has very limited, non-base load steam facilities. Based on these cost estimates, we predict that virtually all the conventional steam generating facilities in the country will be called into full-time service when generation is competitively marketed.

The competitive equilibrium that we forecast earlier involves competitive price being driven to 5.12 cents/kwh as idled capacity is fully employed. We assumed that all prices would fall by the relative proportion that 5.12 cents/kwh is to the overall current average price of 6.9 cents/kwh. An alternative assumption is that the Law of One Price will operate and that all consumers, everywhere will pay 5.12 cents/kwh. Between these extremes we have a spectrum of other possible scenarios. We develop the most likely of these now.

The effect of competition on investor-owned utilities is analyzed in the following fashion. For each utility, we forecast revenue based on a maximum price of 5.12 cents/kwh times the current level of electricity sales plus any additional generation output that the utility undertakes. On the basis of the price declines alone, several of the highest pricing utilities will suffer substantial revenue declines. While these will be partially offset by extra generation, the difference is still substantial. Even though competition will bring revenue shortfalls to many utilities, this does not mean that these utilities will all necessarily suffer financial crisis. To assess the impact of competition on the financial viability of the investor-owned electric utility industry, we construct a forecast of cash flows that will result from a move to competition.

Our outline of financial flows is as follows:

REVENUE	Current Sales Of Electricity		
X	the smaller of current price or 5.12 cents/kwh	=	Revenue from Current Production
	Additional Generation (from operating conventional steam facilities at full capacity)		

51. This forecast assumes that input prices remain constant. In MALONEY, *et al.*, *supra* note 1, we explore alternative scenarios where input prices are influenced by output expansion.

X	5.12 cents/kwh if sold in home market or 3 cents/kwh if sold in wholesale market	=	Revenue from Expanded Production
	SUM	=	Total Production

COSTS

+	Current Power Production Expenses (not including purchased power expenses)		
+	Additional Generation Cost (Cost / kwh estimated as function of capacity utilization)		
+	Forecast Purchase Power Expenses (minimum of current purchases power rate or 3 cents/kwh, except in NY and CA)		
+	Forecast transmission and Distribution costs (estimated as function of price)		
+	Forecast Customer Accounts, Sales, Administration and General Expenses (estimated as function of price)		
	SUM	=	Operating Expenses
+	Taxes (current tax rate H [total revenue-operating expenses-current depreciation])		
+	Forecast Capital Expenditures (estimated as function of type of capacity and price)	=	Total Costs

CASH FLOW

	Total Revenue		
-	Total Costs	=	Net Cash Flow

Our cash flow analysis is built on a modified interpretation of the Law of One Price. We assume that price will fall to the average full-capacity-utilization value that we derived in our earlier work, that is, 5.12 cents/kwh. However, for utilities that are currently selling for less than this, their price will not increase. Competition will cause price to fall on electricity that is currently being sold. At the same time, competition allows for additional sales. We treat these additional sales in the following way: If a utility increases its generation in percentage terms by less than the decline in its price, then we assume that it sells all of its additional power to its existing customers at the 5.12 cents/kwh price. If its generation increase is larger than the decline in its price (for instance, suppose its current price is below 5.12) then we assume that it sells the additional power on the wholesale market at 3 cents/kwh.

Costs are broken down into categories and analyzed as such. We cost current generation at the current level and additional generation at estimated marginal cost as discussed above. Purchased power expenses are priced at 3 cents/kwh or the current price the utility is paying if that is lower, except in New York and California. For utilities in these two states, because of the existence of high priced PURPA purchased power contracts, we assume that purchased power costs will not decline to 3 cents. Since we do not know exactly how much power the various utilities in these two states purchase under PURPA, we assume that the price of their purchased power will fall from its current level half way to the current purchase price of 3 cents.

We find three types of cost to be especially sensitive to the level of the regulated price. These are capital expenditures, transmission and distribution costs (T&D), and customer, sales, general, and administrative costs (CSGA). For each of these, we find that the per kwh cost was positively and statistically significantly related to the level of the regulated price the utility is allowed to charge. We interpret this to mean that there is some regulatory slack in operations and capital costs. For instance, some employees of regulated electric utilities may make higher wages/salaries than their market opportunity wage. At all events, we expect that competition will cause utilities to become more lean, that is, we expect that costs will fall under the impetus of competitive pressures.

In order to account for this, we estimate the log of per unit cost of T&D and CSGA as a function of the difference between the current price and 5.12 where the current price was greater than 5.12 (and zero if smaller). In both cases, this simple regression explains over half of the variation in this average cost measure. We use a modified ridge-regression approach to forecast costs. As our forecast, we use one standard deviation below the cost value given by the estimated equation where the estimated equation is evaluated at a price of 5.12 cents. For those utilities that are currently experiencing cost lower than this we use their actual cost. In the case of

T&D, we multiply forecast average cost by current generation plus the forecast increase in generation from full capacity utilization. For CSGA, we assume that these costs will be relatively unaffected by the expansion of generation.

Our approach to estimating capital costs is very similar. We estimate current capital expenditures per unit of capacity as a function of the type of installed capacity. Specifically, we find that the percentage of capacity that is conventional steam and nuclear is significantly negatively related to current capital expenditures, implying that hydro, combined-cycle, and gas turbine facilities require larger more frequent infusions of capital to maintain their productive capability. Again we find that capital expenditures are significantly related to the level of regulated price. To account for this we regress the log of per capacity capital expenditures on the percent of capacity made up by conventional steam, the percent made up by nuclear, and the difference between regulated price and 5.12 cents if positive. The R^2 of the estimated equation is .5. We forecast capital expenditures as one standard deviation below the mean value given by the estimated equation evaluated at a price of 5.12 cents, or actual capital expenditures where those are lower.

Finally, we based taxes on an overall rate of 35 percent applied to taxable income. Taxable income is revenue minus operating expenses minus depreciation. We used the current level of depreciation. Of course tax rates vary around this. However, in a competitive environment there will be less political influence affecting rates. Our prediction is that they will tend toward this value.

The fair market value of the firm is the capitalized value of the net cash flows. We discount these cash flows at a real interest rate of eight percent, which is based on a risk-adjusted rate for equity in competitive electric power production of 12 percent less an inflation rate of four percent. Table 5 shows the estimated fair market value of utility assets, forecast equity value, and estimated true stranded costs for the 98 investor-owned utilities in the sample.

Table 1

Accounting and Market Valuation Methods

	Original Scenario	After 5 Years, Before Revenue Decline	After 5 Years, After Revenue Decline
Accounting Method	$1,000,000	$500,000	$500,000
Net Cash Flow Valuation Method	$1,742,513	$1,123,786	$224,775
Stranded Costs	$0	$0	$500,000 - $224,775 = $275,224
Equity Value of Business if Continue to Operate	$1,742,513	$1,123,786	$224,775
Equity Value of Business if Facility is Abandoned	$0	$0	$0

Table 2

Market Value of Equity Divided by Book Value of Equity 1993-1995 & Market Equity 1995 Value Line Utilities

Utility	Market to Book 1993	1994	1995	Market Equity 1995
Allegheny Power System Inc	1.56	1.34	1.68	$3,591
American Electric Power Co	1.61	1.42	1.81	7,808
Atlantic Energy Inc NJ	1.47	1.21	1.12	920
Baltimore Gas & Electric Co	1.34	1.22	1.43	3,963
Black Hills Corp	2.13	1.67	1.91	344
Boston Edison Co	1.52	1.28	1.26	1,293
Carolina Power & Light Co	1.88	1.59	1.97	5,191
Centerior Energy Corp	1.32	.85	.63	1,221
Central Hudson Gas & Elec Co	1.30	1.05	1.13	592
Central Louisiana Elec Inc	1.72	1.53	1.57	446
Central Maine Power Co	1.14	.85	.91	170
Central Vermont Public SVC Corp	1.52	1.17	.96	5,347
Central & South West Corp	2.01	1.59	1.68	514
Colcorp Inc	1.51	1.25	1.55	565
Cinergy Corp	1.55	1.56	1.84	4,650
CIPSCO Inc	1.70	1.47	1.99	1,294
CMS Energy Corp	2.01	1.74	1.87	2,685
Commonwealth Energy System	1.39	1.18	1.25	472

Consolidated Edison of New York	1.57	1.22	1.35	7,435
Delmarva Power & Light Co	1.61	1.36	1.43	1,324
Detroit Edison Co.	1.49	1.19	1.44	4,957
Dominion Resources Inc	1.66	1.51	1.46	6,915
DPL Inc	2.04	1.90	2.05	2,389
DQE	1.47	1.27	1.67	2,211
Duke Power Co	1.90	1.71	2.10	10,053
Eastern Utilities Association	1.53	1.33	1.16	430
Edison International (SCE)	1.72	1.20	1.20	7,674
Empire District Electric Co	1.77	1.42	1.35	247
Enova Corp (San Diego G & E)	1.96	1.68	1.67	2,739
Entergy Corp	1.28	1.05	.97	6,335
Florida Progress Corp	1.66	1.40	1.57	3,278
FPL Group Inc	1.77	1.48	1.85	8,163
General Public Utilities	1.33	1.24	1.26	3,735
Green Mountain Power Corp	1.57	1.26	1.25	132
Hawaiian Electric Industries	1.50	1.39	1.45	1,046
Houston Industries Inc	1.84	1.42	1.35	5,646
Idaho Power Co	1.69	1.46	1.62	1,066
IES Industries	1.55	1.26	1.36	827
Illinova Corp	1.32	1.06	1.39	2,135
Interstate Power Corp	1.56	1.27	1.48	293
IPALCO	1.92	1.50	1.76	1,452

Kansas City Power & Light Co	1.72	1.50	1.75	1,569
KU Energy	1.61	1.65	1.73	1,087
LG & E Energy Corp	1.74	1.61	1.77	1,411
Long Island Lighting Co	1.33	.97	.86	2,111
MDU Resources Inc	1.76	1.67	1.86	627
MidAmerican Energy	1.42	1.23	1.46	1,782
Minnesota Power & Light Co	1.84	1.61	1.32	788
Montana Power Co	1.52	1.34	1.22	1,187
Nevada Power Co	1.58	1.31	1.32	1,023
New England Electric System	1.70	1.40	1.49	2,413
New York State Elec & Gas Corp	1.43	1.04	.94	1,638
Niagara Mohawk Power Corp	1.29	.96	.39	983
NIPSCO Industries Inc	1.83	1.70	2.05	2,279
Norhteast Utilities	1.43	1.25	1.04	2,504
Northern States Power Co MN	1.61	1.51	1.65	3,314
Northwestern Public Service Co	2.09	1.81	1.75	266
Ohio Edison Co	1.60	1.29	1.37	3,273
Oklahoma Gas & Electric Co	1.59	1.46	1.67	1,600
Orange & Rockland Utilities Inc	1.55	1.25	1.42	538
Otter Tail Power Co	2.36	2.063	2.31	426

Pacific Gas & Electric Co	1.73	1.41	1.20	10,430
PACIFICORP	1.62	1.45	1.64	5,291
PECO Energy Co	1.53	1.38	1.32	6,000
Pinnacle West Capital Corp	1.19	.95	1.29	2,453
Portland General Corp	1.23	1.09	1.49	1,299
Potomac Electric Power Corp	1.59	1.36	1.61	3,004
PPL Resources Inc	1.79	1.45	1.48	3,819
Public Service Co of CO	1.55	1.37	1.65	2,215
Public Service Co of NM	.89	.81	1.09	762
Public Service Enterprise Group	1.57	1.29	1.20	6,475
Puget Sound Power & Light Co	1.43	1.12	1.37	1,588
Rochester Gas & Electric Co	1.37	1.17	1.11	838
Scana Corp	1.62	1.55	2.12	2,714
Sierra Pacific Resources	1.24	1.09	1.39	735
SIG Corp	1.88	1.54	1.65	523
Southern Co	1.76	1.58	1.81	15,723
Southwestern Public Service Co	1.88	1.60	1.85	1,334
St Joseph Light & Power Co	1.75	1.39	1.56	126
TECO Energy Inc	2.57	2.20	2.48	2,854
Texas Utilities Co	1.56	1.26	1.59	9,034
TNP Enterprises Inc	.85	.94	1.09	246
Tucson Electric Power Co	8.33	13.46	39.13	503
UNICOM Corp	1.08	.98	1.10	6,404

Union Electric Corp	1.86	1.58	1.74	4,089
Unites Illuminating Co	1.46	1.13	1.17	518
Utilicorp United Inc	1.51	1.40	1.43	1,083
Washington Water Power Co	1.60	1.31	1.46	1,049
Western Resources Inc	1.47	1.27	1.22	1,876
Wisconsin Energy Corp	1.73	1.58	1.69	3,109
WPL Holdings Inc	1.78	1.53	1.56	766
WPS Resources Corp	1.84	1.60	1.66	771

Notes: Market equity in millions. Data in table are constructed from Value Line Ratings and Reports, Value Line Publishing, Inc., 1996 and Wall Street Journal, Company Briefing Book, online service, March 1996. Market value of equity for 1993 and 1994 are average of high and low stock price for the year. Market value of equity for 1995 is based on year end stock price.

Table 3

Price and Average Cost Across Investor-Owned Utilities

Utility	Average Revenue	Average Costs All Facilities O&M	Conventional Steam O&M	Fossil Fuel	Nuclear O&M
Long Island LTG Co	151.4	60.2	35.6	28.2	19.7
Consolidated Edison Co NY Inc	133.6	66.8	47.4	28.6	16.9
Citizens Utilities Co	106.7	73.6	24.3	NA	NA
Pacific Gas & Elec Co	105.9	60.5	25.8	18.3	21.4
Fitchburg Gas & Elec Lt Co	103.4	71.3	35.3	25.3	14.3
Edison International	99.9	66.0	27.3	22.1	18.3
United Illum Co	98.8	55.0	30.2	21.6	25.8
Bangor Hydro Electic Co	98.0	77.8	45.8	27.5	NA
Boston Edison Co	97.5	62.9	31.8	22.8	31.3
Enova Corp	93.6	52.3	41.5	30.9	22
Public Service Enterprise Group	93.4	42.5	21.4	8.6	24.1
Atlantic Energy Inc NJ	91.5	53.8	28.7	18.9	28.2
Orange & Rockland Utils Inc	89.9	57.8	31.8	25.1	NA
Rochester Gas & Elec Corp	89.2	41.5	28.8	17.4	21.5

Niagara Mohawk Power Corp	85.0	56.6	26.0	19.3	18.9
Maine Public Service Co	84.8	60.3	88.7	30.1	NA
Public Service Co Of NH	83.8	51.8	24.2	17.8	15.2
General Public Utils Corp	83.8	53.4	23.3	16.2	28.7
Centerior Energy Corp	82.1	43.0	28.1	16.9	31.9
Central Hudson Gas & Elec Corp	81.6	45.2	28.4	21.6	21.9
Northeast Utilities	80.9	47.4	39.7	25.8	27
Pinnacle West Capital Corp	80.4	35.7	19.8	14.3	25.1
New York St Elec & Gas Corp	80.1	42.7	20.6	15.6	25.7
New England Elec System	80.0	62.6	33.6	23.1	17.7
P E C O Energy Co	78.3	42.1	33.4	19.2	19.6
Eastern Utilities Associaties	77.8	65.2	29.3	21.6	22.8
D Q E	76.3	38.7	21.0	16.3	36.8
Detroit Edison Co	75.5	36.3	20.5	16.2	1,837.4
Ohio Edison Co	74.9	38.3	19.8	14.3	47.3
TNP Enterprises Inc	73.9	51.5	23.4	20.1	NA
Unicom Corp Holding Co	73.4	38.0	34.7	26.0	19.6
Sierra Pacific Resources	73.3	49.4	27.3	23.4	NA

Commonwealth Energy Sys	73.1	59.8	28.7	23.1	27.6
Green Mountain Power Corp	71.8	54.0	55.6	35.8	NA
El Paso Elec Co	71.2	48.0	25.2	19.8	41.7
Central Vermont Public Service Corp	70.7	55.6	66.5	42.9	18.2
Florida Progress Corp	69.3	41.2	24.0	20.0	20.9
Potomac Electric Power Co	69.2	37.7	24.6	197.7	NA
F P L Group Inc	69.0	38.1	25.2	21.3	21.7
Tucson Electric Power Co	68.9	44.5	33.0	21.1	NA
T E C O Energy Inc	68.3	42.9	27.8	22.9	NA
D P L Inc	66.8	28.9	18.2	13.8	NA
Public Service Co NM	66.8	40.9	23.6	17.9	52.8
Pennsylvania Power & Light Co	65.4	36.7	23.7	17.3	17.8
NIPSCO Industries Inc	64.0	33.4	23.9	17.1	NA
Nevada Power Co	64.0	45.5	22.7	15.7	NA
Black Hills Corp	63.9	39.5	18.5	11.2	NA
CMS Energy Corp	63.5	42.7	20.6	16.2	25.5
Dominion Resources Inc	63.4	37.8	19.6	15.3	13.1
Texas Utilities Co	63.4	32.9	21.5	18.0	18.7
Carolina Power & Light Co	63.1	36.7	22.3	17.7	20.7

Utilicorp United Inc	62.7	37.8	19.5	13.5	NA
Baltimore Gas & Electric Co	62.6	34.1	21.7	16.3	19
Houston Industries Inc	61.1	34.4	20.7	16.7	21.1
Northwestern Public Service Co	60.9	0.2	0.2	10.5	NA
Delmarva Power & Light Co	60.0	36.2	27.0	19.8	26
Public Service Co of CO	58.7	41.0	16.1	12.0	NA
Madison Gas & Electric Co	58.6	34.4	20.8	14.3	20.3
Northern States Power Co MN	58.4	36.8	17.8	12.6	14.9
Central Louisiana Elec Inc	57.4	33.3	21.8	19.2	NA
Duke Power	56.8	35.5	20.0	15.6	16.1
Western Resources Inc	56.6	27.5	19.2	13.3	14.5
Oklahoma Gas & Electric Co	56.5	37.7	18.7	16.1	NA
Midamerican Energy	56.1	31.9	14.2	10.5	43.8
MDU Resources Group Inc	55.8	35.1	18.2	12.2	NA
Entergy Corp New	55.5	35.5	25.1	21.6	18.5
Puget Sound Power & Light Co	54.5	31.8	13.8	7.6	NA
Southern Co	54.2	30.6	22.5	17.7	15.5

Central Maine Power Co	54.0	39.6	52.3	25.5	16.3
Union Electric Co	53.9	26.5	18.7	13.1	12.7
CilCorp Inc	53.7	31.3	21.8	17.2	NA
Kansas City Power & Light Co	53.0	27.1	14.5	9.9	14.9
Wisconsin Energy Corp	52.2	31.4	18.4	13.7	14
Central & South West Corp	52.1	31.6	22.0	19.6	20.3
IES Industries Inc	51.5	29.2	15.6	12.1	23.9
SCANA Group	51.5	28.1	18.3	15.9	23.6
CIPSCO Inc	50.1	30.9	23.7	17.5	NA
IPALCO Enterprises Inc	49.5	25.9	16.3	11.8	NA
Allegheny Power Systems Inc	49.4	33.3	18.7	14.0	NA
Portland General Group	49.1	28.4	16.1	11.5	NA
Interstate Power Co	48.7	33.1	22.1	18.3	NA
Cincinnati Gas & Electric Co	48.6	29.3	18.1	14.4	NA
WPL Holdings Inc	48.6	29.2	17.8	14.6	21.1
St Joseph Light & Power Co	47.8	26.5	16.6	14.8	NA
Empire District Electric Co	47.3	28.4	14.6	11.4	NA
Southern Indiana Gas & Elec Co	46.9	27.6	20.8	15.2	NA

Otter Tail Power Co	46.1	27.9	15.9	11.7	NA
WPS Resources Holding Co	45.6	29.6	20.3	14.3	17
LG&E Energy Corp	45.5	27.2	17.5	12.1	NA
PACIFICCORP	44.6	24.4	13.9	10.0	NA
Washington Water Power Co	44.5	23.9	15.8	11.3	NA
Montana Power Co	43.2	27.4	18.3	7.6	NA
Illinova Corp Holding Co	42.1	22.8	18.1	13.7	19.8
Southwestern Public Service Co	40.8	26.14	19.9	18.0	NA
Minnesota Power & Light Co	39.8	25.5	16.7	12.6	NA
American Electric Power Inc	39.4	26.4	19.0	14.5	25.4
Idaho Power Co	37.5	21.4	17.7	13.1	NA
KU Energy Corp	36.2	34.4	14.2	11.0	NA

Notes: Units in dollars per megawatthour. Upper Peninsula Energy and ESELCO are omitted because of missing data. Hawaiian Electric Industries is excluded because it is not interconnected. Data are from FERC Form 1 as available from the Energy Information Administration of the U.S. Department of Energy.

Table 4

Current Electricity Generation and Extra Generation Available From Full Capacity Utilization

Utility	*Current Generation* Total From All Sources	Conventional Steam	*Full Capacity Ulitlization* Capacity Utilization	Additional Power	Percentage Increase
Allegheny Power Systems Inc	38,785	38,959	63.1%	5,040	13.0%
American Electic Power Inc	137,675	127,417	61.6%	20,591	15.0%
Atlantic Energy Inc NJ	5,430	2,853	46.2%	1,571	28.9%
Baltimore Gas & Electric Co	29,705	17,125	50.6%	7,120	24.0%
Bangor Hydro Electric Co	216	34	9.5%	221	102.3%
Black Hills Corp	1,109	1,103	86.0%	0	0.0%
Boston Edison Co	9,429	5,594	36.3%	5,439	54.7%
CIPSCO Inc	11,224	11,224	47.5%	5,708	50.9%
CMS Energy Corp	22,785	17,799	53.8%	5,525	24.2%
Carolina Power & Light Co	40,462	21,001	49.2%	9,547	23.6%
Centerior Energy Corp	29,795	18,136	51.1%	7,155	24.0%
Central Hudson Gas & Electric Corp	3,782	2,937	37.9%	2,559	67.6%
Central Louisiana Electric Inc	6,234	6,233	45.8%	3,517	56.4%

Central Maine Power	17,151	534	7.7%	4,435	25.9%
Central Vermont Public Service Corp	382	25	18.9%	71	18.5%
Central & South West Corp	57,827	54,195	50.6%	22,490	38.9%
CilCorp Inc	5,675	5,674	58.6%	1,263	22.2%
Cincinnati Gas & Electric Co	50,330	49,821	60.0%	9,665	19.2%
Citizens Utilities Co	327	50	57.5%	12	3.8%
Commonwealth Energy Co	3,984	3,762	44.1%	2,342	58.8%
Consolidated Edison Co NY Inc	20,420	12,397	28.4%	18,900	92.6%
DPL Inc	14,510	14,483	58.5%	3,239	22.3%
D Q E	15,436	11,217	55.8%	3,163	20.5%
Delmarva Power & Light Co	11,582	7,740	50.8%	3,158	27.3%
Detroit Edison Co	42,440	42,890	69.9%	986	2.3%
Dominion Resources Inc	53,649	27,163	52.5%	9,493	17.7%
Duke Power Co	70,362	32,714	48.3%	15,229	21.6%
Eastern Utilities Association	3,034	1,716	60.2%	326	10.8%
Edison International	54,023	31,864	42.7%	21,472	39.7%
El Paso Elec Co	7,018	3,367	56.6%	894	12.7%
Empire District Electric Co	2,630	2,495	76.6%	0	0.0%
ENOVA Corp	7,746	4,042	24.9%	7,571	97.7%

Entergy Corp NEW	89,068	54,992	37.4%	50,225	56.4%
FPL Group Inc	66,733	31,676	47.0%	16,618	24.9%
Fitchburg Gas & Elec Light Co	78	56	31.6%	71	91.6%
Florida Progress Corp	24,740	18,838	51.9%	7,127	28.8%
General Public Utilities Corp	29,152	16,919	55.7%	4,715	16.2%
Green Mountain Power Corp	153	16	18.9%	44	28.8%
Houston Industries Inc	53,895	48,104	46.2%	26,478	49.1%
IES Industries Inc	8,407	5,509	69.3%	187	2.2%
Idaho Power Co	13,435	7,222	83.0%	0	0.0%
Illinova Corp Holding Co	26,835	20,397	45.3%	11,816	44.0%
Interstate Power Co	3,411	3,409	34.6%	3,640	106.7%
IPALCO Enterprises Inc	13,580	1,356	66.0%	1,154	8.5%
KU Energy Corp	15,525	15,417	59.9%	3,024	19.5%
Kansas City Power & Light Co	16,159	12,150	65.4%	1,144	7.1%
LG&E Energy Corp	12,229	11,894	71.5%	15	0.1%
Long Island LTG Co	10,034	8,365	35.2%	8,638	86.1%
MDU Resources Group Inc.	1,901	1,890	62.0%	292	15.4%
Madison Gas & Electric Co	2,252	1,534	48.1%	750	33.3%
Maine Public Service Co	24	19	5.8%	207	879.4%

MidAmerican Energy	15,183	13,644	72.7%	0	0.0%
Minnesota Power & Light Co	6,251	5,557	60.8%	990	15.8%
Montana Power Co	9,550	6,550	78.2%	0	0.0%
NIPSCO Industries Inc	14,485	14,400	51.7%	5,541	38.3%
Nevada Power Co	6,482	560	351.2%	2,238	34.5%
New England Electric Sys	13,900	10,972	53.1%	3,640	26.2%
New York St Electric & Gas Corp	16,169	14,338	77.6%	0	0.0%
Niagara Mohawk Power Corp	19,681	8,728	27.1%	14,171	72.0%
Northeast Utilities	19,735	3,631	25.2%	6,192	31.4%
Northern States Power Co MN	33,632	20,431	60.6%	3,690	11.0%
Northwestern Public Service Co	1,236	1,233	66.3%	99	8.0%
Ohio Edison Co	31,319	23,870	64.1%	2,790	8.9%
Oklahoma Gas & Electric Co	18,326	17,891	37.1%	16,633	90.8%
Orange & Rockland Utilities Inc	3,410	3,282	66.8%	232	6.8%
Otter Tail Power Co	2,832	2,805	57.8%	668	23.6%
PECO Energy Co	40,851	11,240	46.6%	5,722	14.0%
Pacific Gas & Electric Co	58,158	35,557	69.2%	1,244	2.1%
PACIFICORP	54,928	51,644	85.9%	0	0.0%

Pennsylania Power & Light Co	37,874	23,301	46.7%	12,429	32.8%
Pinnacle West Capitol Corp	19,932	12,377	63.6%	1,556	7.8%
Portland General Corp	9,706	4,918	84.8%	0	0.0%
Potomac Electric Power Co	19,320	18,803	44.6%	11,392	59.0%
Public Service Co of CO	16,093	15,950	67.5%	955	5.9%
Public Service Co of NM	8,457	6,101	60.2%	1,155	13.7%
Public Service Co of NH	5,252	4,661	57.9%	1,105	21.0%
Public Service Enterprise Group	29,747	10,833	29.1%	15,554	52.3%
Puget Sound Power & Light Co	7,012	5,527	75.4%	0	0.0%
Rochester Gas & Electric Corp	6,097	1,478	31.4%	1,781	29.2%
SCANA Corp	16,986	13,705	71.4%	43	0.3%
Sierra Pacific Resources	3,895	3,835	55.9%	1,079	27.7%
Southern Co	141,551	106,617	56.7%	27,978	19.8%
Southern Indiana Gas & Electric Co	5,435	5,409	54.6%	1,687	31.0%
Southwestern Public Service Co	21,415	21,270	63.7%	2,623	12.3%
St Joseph Light & Power Co	1,166	1,160	45.7%	655	56.2%
TECO Energy Inc	16,103	16,071	59.7%	3,214	20.0%

TNP Enterprises Inc	2,337	2,337	83.8%	0	0.0%
Texas Utilities Co	81,321	66,385	49.0%	30,574	37.6%
Tuscon Electric Power Co	10,167	10,159	6.6%	920	9.1%
UNICOM Corp Holding Co	90,243	26,361	31.2%	34,088	37.8%
Union Electric Co	33,662	21,921	47.6%	11,001	32.7%
United Illum Co	4,947	3,513	59.0%	750	15.2%
UtiliCorp United Inc	5,660	5,626	51.1%	2,258	39.9%
WPL Holdings Inc	9,698	7,821	96.3%	0	0.0%
WPS Resources Group Holding Co	9,014	7,048	60.7%	1,266	14.0%
Washington Water Power Co	6,331	3,400	83.2%	0	0.0%
Western Resources Inc	20,562	16,532	53.6%	5,570	27.1%
Wisconsin Energy Corp	26,429	18,328	58.0%	4,288	16.2%

Notes: Data are taken from Forms 860 and 759 available from the Energy Information Administration of the U.S. Department of Energy.

Table 5

Forecast of Fair Market Value (FMV) and True Stranded Costs

Estimated Total Stranded Costs: $41,988,598

Utility	Forecast FMV of Utility Assets	Long Term Debt	Forecast Equity Value	Book Value of Utility Assets	Estimated Stranded Costs
Allegheny Power Systems Inc	8,789,815	1,938,306	71,605.62	4,361,691	0
American Electic Power Inc	17,013,174	4,875,401	13,563,295	1,100,574	0
Atlantic Energy Inc NJ	1,162,729	765,130	468,064	1,781,923	619,194
Baltimore Gas & Electric Co	7,235,474	2,306,342	5,277,018	5,531,371	0
Bangor Hydro Electric Co	267,981	117,828	156,009	218,741	0
Black Hills Corp	230,055	131,061	98,994	309,191	79,136
Boston Edison Co	2,906,732	1,202,842	2,397,830	2,796,778	0
CIPSCO Inc	2,367,504	474,620	1,894,139	1,426,804	0
CMS Energy Corp	5,979,917	1,918,098	4,238,903	4,197,983	0
Carolina Power & Light Co	9,429,862	2,805,823	6,693,528	6,349,484	0
Centerior Energy Corp	4,964,876	4,014,502	1,250,423	6,986,637	2,021,761
Central Hudson Gas & Electric Corp	1,733,667	388,048	1,345,619	931,073	0

Central Louisiana Electric Inc	1,299,777	349,955	949,822	911,678	0
Central Maine Power	4,938,652	1,182,187	5,244,589	1,601,260	0
Central Vermont Public Service Corp	893,575	177,044	716,531	391,940	0
Central & South West Corp	9,833,026	2,854,022	7,542,314	7,352,503	0
CilCorp Inc	1,101,700	278,359	832,230	867,050	0
Cincinnati Gas & Electric Co	8,854,683	2,774,887	6,676,624	6,188,419	0
Citizens Utilities Co	0	942,258	(912,190)	1,106,336	1,106,336
Commonwealth Energy Co	1,675,581	289,879	1,497,705	730,974	0
Consolidated Edison Co NY Inc	3,428,560	4,041,353	(612,793)	10,548,656	7,120,096
DPL Inc	3,720,962	1,001,019	2,878,253	2,259,523	0
D Q E	3,103,794	1,428,528	3,477,096	3,049,721	0
Delmarva Power & Light Co	2,303,258	834,137	1,469,121	2,046,997	0
Detroit Edison Co	7,393,510	3,806,910	5,565,167	8,879,581	1,486,071
Dominion Resources Inc	13,306,141	4,222,674	9,679,178	9,651,096	0
Duke Power Co	14,682,272	3,541,152	11,486,702	9,296,741	0
Eastern Utilities Association	1,321,956	498,391	840,091	815,200	0
Edison International	9,558,489	5,189,253	4,369,236	12,416,547	2,858,058

El Paso Elec Co	654,574	0	1,080,420	1,183,414	528,840
Empire District Electric Co	433,093	185,067	270,743	445,835	12,743
ENOVA Corp	2,818,289	1,234,254	1,584,035	3,149,092	330,803
Entergy Corp NEW	20,513,454	760,795	18,622,857	1,525,876	0
FPL Group Inc	13,829,782	3,667,507	1,413,861	1,006,153	0
Fitchburg Gas & Elec Light Co	47,718	34,000	13,718	63,395	15,677
Florida Progress Corp	4,372,555	1,399,183	3,167,172	3,669,252	0
General Public Utilities Corp	7,041,773	2,767,151	4,274,622	6,207,036	0
Green Mountain Power Corp	81,797	79,800	11,104	175,987	94,191
Houston Industries Inc	12,771,121	3,176,612	9,735,755	8,976,028	0
IES Industries Inc	2,015,014	480,544	1,947,536	1,278,077	0
Idaho Power Co	1,361,942	693,723	668,218	1,654,890	292,948
Illinova Corp Holding Co	6,678,650	1,998,158	5,134,307	4,727,168	0
Interstate Power Co	847,304	202,917	747,719	500,681	0
IPALCO Enterprises Inc	2,465,485	654,121	1,811,364	1,711,772	0
KU Energy Corp	1,712,503	496,033	1,219,891	1,409,917	0
Kansas City Power & Light Co	3,709,919	780,518	3,196,322	2,336,142	0
LG&E Energy Corp	1,697,509	662,862	1,059,535	1,653,894	0

Long Island LTG Co	1,656,862	5,170,397	(1,748,832)	3,497,591	1,840,729
MDU Resources Group Inc.	496,189	202,293	314,438	350,224	0
Madison Gas & Electric Co	509,997	139,320	370,677	336,989	0
Maine Public Service Co	105,856	37,500	88,549	45,663	0
MidAmerican Energy	3,096,315	1,231,813	2,349,062	2,645,159	0
Minnesota Power & Light Co	1,187,724	433,395	755,641	769,600	0
Montana Power Co	1,363,591	587,660	932,065	1,391,247	27,656
NIPSCO Industries Inc	3,463,046	1,088,537	2,565,914	3,107,569	0
Nevada Power Co	1,341,073	612,298	728,775	1,584,003	242,929
New England Electric Sys	5,769,037	1,390,744	4,957,665	3,755,551	0
New York St Elec & Gas Corp	3,677,992	1,620,083	2,506,509	3,979,252	301,260
Niagara Mohawk Power Corp	8,466,769	3,331,531	5,155,868	7,008,545	0
Northeast Utilities	4,944,476	2,619,177	4,646,226	5,487,355	542,879
Northern States Power Co MN	7,425,252	1,484,778	6,167,412	4,230,554	0
Northwestern Public Service Co	239,995	123,850	116,145	242,286	2,291
Ohio Edison Co	5,409,754	3,236,249	2,300,013	5,800,088	390,334

Oklahoma Gas & Electric Co	5,179,346	749,017	4,780,395	2,042,565	0
Orange & Rockland Utilities Inc	586,093	370,478	521,719	850,392	264,299
Otter Tail Power Co	823,274	140,558	689,069	432,543	0
PECO Energy Co	8,167,367	5,228,052	3,631,035	10,834,490	2,667,123
Pacific Gas & Electric Co	6,190,717	8,336,989	(1,899,639)	18,481,153	12,290,436
PACIFICORP	10,386,407	3,186,342	7,207,793	7,474,088	0
Pennsylania Power & Light Co	10,056,827	2,940,789	7,238,154	7,126,676	0
Pinnacle West Capitol Corp	3,950,334	2,174,732	2,049,251	4,624,073	673,739
Portland General Corp	2,666,433	874,153	2,059,348	1,690,892	0
Potomac Electric Power Co	4,461,563	1,768,844	3,666,973	4,291,295	0
Public Service Co of CO	3,901,912	1,111,242	3,934,179	3,173,986	0
Public Service Co of NM	1,268,709	900,595	400,844	1,666,458	397,750
Public Service Co of NH	2,006,290	999,985	1,441,482	701,716	0
Public Service Enterprise Group	8,317,875	4,951,627	3,375,785	10,936,244	2,618,369
Puget Sound Power & Light Co	3,735,413	1,071,298	2,748,385	2,266,911	0
Rochester Gas & Electric Corp	1,908,327	735,178	1,758,161	1,696,055	0

SCANA Corp	2,962,616	1,356,790	1,967,072	3,168,017	205,401
Sierra Pacific Resources	805,775	521,216	322,049	1,331,478	525,703
Southern Co	27,905,711	7,239,314	21,783,672	20,070,515	0
Southern Indiana Gas & Electric Co	705,619	296,359	448,889	677,936	0
Southwestern Public Service Co	2,241,130	522,341	1,738,018	1,518,085	0
St Joseph Light & Power Co	282,440	53,100	231,304	148,248	0
TECO Energy Inc	2,302,365	608,530	2,238,361	1,985,162	0
TNP Enterprises Inc	992,952	685,502	312,319	967,273	0
Texas Utilities Co	19,904,351	7,276,678	12,700,499	18,297,962	0
Tuscon Electric Power Co	1,019,000	1,398,950	(377,240)	1,820,783	801,783
UNICOM Corp Holding Co	20,072,192	8,161,725	13,189,755	17,016,541	0
Union Electric Co	9,244,960	1,773,451	7,471,509	5,320,852	0
United Illum Co	918,271	901,473	54,993	1,357,258	438,987
UtiliCorp United Inc	1,355,203	770,295	701,741	1,463,565	108,361
WPL Holdings Inc	1,652,292	336,538	1,345,629	1,200,080	0
WPS Resources Group Hold Co	1,489,942	316,121	1,262,016	799,606	0
Washington Water Power Co	425,956	709,982	(284,026)	1,329,045	903,089
Western Resources Inc	4,114,490	1,656,455	4,118,348	4,294,115	179,625

Wisconsin Energy Corp	5,826,145	1,167,408	4,658,738	2,692,700	0

Notes: Forecast equity value includes cash flows from subsidiaries. Amounts are in thousands. Source, see note, Table 2.

Table 6

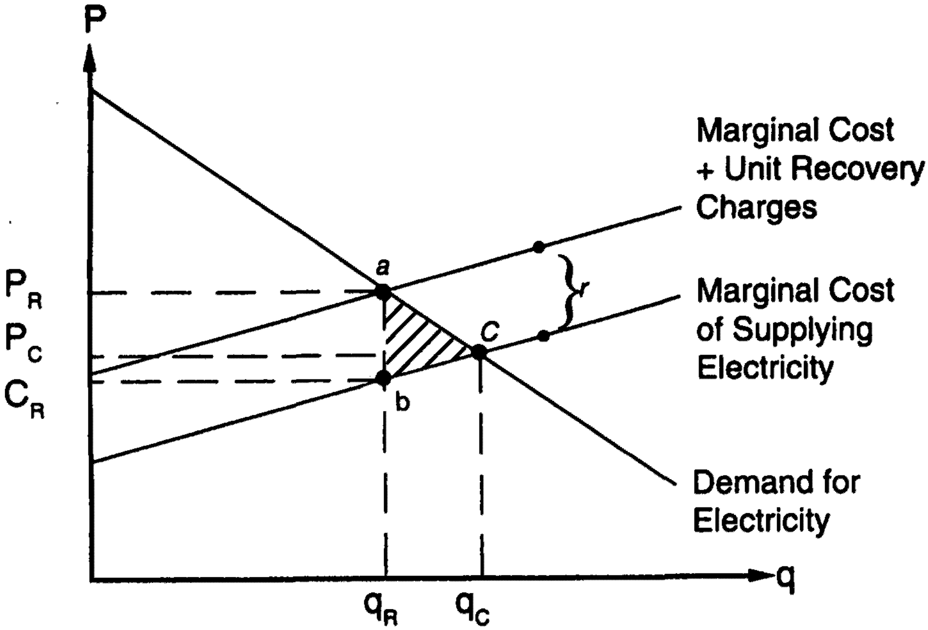
Yields on Government and Electric Utility Bonds

Date	Overall Electric Utility Bond Yields	Government Bond Yield	Difference
December 1990	9.58%	8.28%	1.30%
December 1989	9.33%	7.99%	1.34%
December 1988	10.09%	9.10%	.99%
December 1987	10.91%	9.20%	1.71%
December 1986	9.00%	7.68%	1.32%
December 1985	10.56%	10.18%	.38%

Sources: Statistical Yearbook of the Electric Utility Industry/1990, Edison Electric Institute, page 92 and Federal Reserve Electronic Database, Internet, Long-Term Government Securities, Excluding flower Bonds.

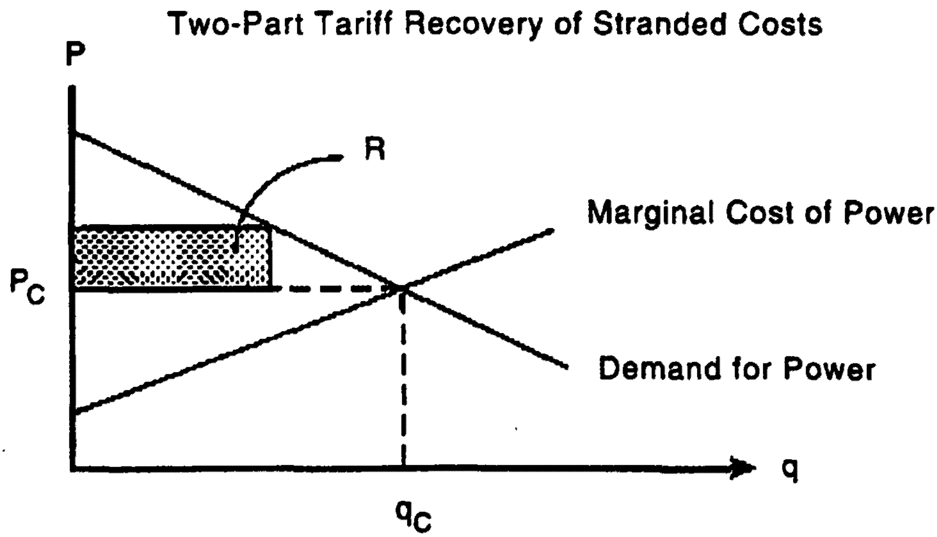
Figure 1

Unit Charge Recovery of Stranded Costs



P_C - Price Under Competition
q_C - Quantity Under Competition
r - Unit Recovery Fee
P_R - Price with Recovery
$r \cdot q_R$ - Amount of Stranded Cost Recovery
C_R - Cost of Electricity Excluding Recovery

Figure 2


Two-Part Tariff Recovery of Stranded Costs
P
R
Marginal Cost of Power
P_C
Demand for Power
q
q_C