Financing Difficulties of the New England Electric Utilities

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In 1974 construction of some 235 electric power plants was postponed or cancelled.[1] In part these deferrals were the result of revised demand projections but for many utilities they reflect an inability to generate substantial funds internally or raise outside capital at an acceptable price.

This paper examines how New England fared in the recent crisis, focusing on the eight largest investor-owned utilities which account for over 96 percent of the region's generation.[2] Part I discusses the general industry problems of massive capital requirements, dependence upon external funding and the erosion of the ability to attract these investment funds. Part II considers the New England experience showing how these problems have been intensified by an unusually large construction program and the effects of the energy crisis.

I. The Industry Problem

The Need for Capital

The capital requirements of the electric utility industry are vast. Since 1967 electric utilities have accounted for more than 10 percent of all new plant and equipment expenditures. Moreover, in the five years between 1967 and 1972, their share grew dramatically; so that even with recent cutbacks, electric utilities still accounted for approximately 15 percent of total capital expenditures in 1974 and the first half of 1975. (Table 1)

There is, of course, considerable uncertainty as to the industry's future construction requirements. As of the end of September, kilowatt-hour

[1] *Wall Street Journal*, June 4, 1975.

[2] This figure, which is for 1973, includes the companies' shares of jointly owned nuclear plants. Source: Calculated from individual company prospectuses; National Coal Association, *Steam Electric Plant Factors, 1974*, and the Edison Electric Institute, *Statistical Yearbook*, 1973.

Table 1

NEW PLANT AND EQUIPMENT EXPENDITURES — BILLIONS OF CURRENT DOLLARS

	All Industries	Public Utilities—Electric	Electric Utilities As a Percent of All Industry
1975-I+II, annual rate	113.52	16.72	14.7
1974	112.40	17.63	15.6
1973	99.74	15.94	15.9
1972	88.44	14.48	16.3
1971	81.21	12.86	15.8
1970	79.71	10.65	13.3
1969	75.76	8.94	11.8
1968	67.76	7.66	11.3
1967	65.47	6.75	10.3
1966	63.51	5.38	8.4

Source: *Survey of Current Business,* Table S-2.

output for 1975 was less than 1.7 percent[3] above the corresponding period in 1974; and debate goes on both within and without the industry as to whether this low growth represents a permanent response to higher rates or merely a temporary aberration. In general, however, most observers agree that while a return to growth rates of 7 and 8 percent is unlikely as long as real prices remain high, the demand for electricity will pick up as the economy improves and the shock of the high prices wears off. In the long run, growth will be further strengthened by a trend away from the use of oil and gas towards relatively flexible[4] and hence, more secure electricity.

Economic Growth in the Future, a Report of the Edison Electric Institute Committee on Economic Growth, Pricing and Energy Use, has estimated that for the 25-year period, 1974 through 1990, the consumption of electric energy in kilowatt-hours will grow at an annual rate of 5.3 to 5.8 percent. Construction expenditures are forecast to rise 10 percent per year, reflecting the shift away from oil and natural gas plants to the more

[3]Edison Electric Institute, *Electric Output,* October 1, 1975.

[4]Many fossil-fueled plants can be switched at some cost from one fuel to another. Moreover, most utilities have a mix of generating sources so that relying on electricity is seen as spreading one's risks.

capital intensive coal, nuclear and pumped storage hydro capacity. Total capacity needs for the period in current dollars are estimated to be $750 billion.[5]

For the shorter time period of 1975 through 1980, Murray Weidenbaum has estimated total capital outlays at $120 billion.[6] If past trends continue, 60 to 70 percent of these funds will be raised externally.

Internal Funding

In 1964 approximately 60 percent of the electric utilities total capital funding came from internal sources; by 1972 this had fallen to just over 30 percent (Table 2(a)). Two-thirds of the decline can be attributed to the decreasing importance of depreciation. As Table 3 shows, depreciation is approximately 3.02 percent of the book value of operational electric plant and with construction expenditures growing at an annual rate of approximately 17 1/2 percent over this period, the increase in electric plant and consequently depreciation has simply not kept pace. In the mid-sixties existing plant in service was so large relative to construction expenditures that even large dollar additions to plant resulted in relatively small percentage increases, and consequently depreciable plant and therefore depreciation grew much more slowly than new construction.[7] Furthermore,

[5]*Economic Growth in the Future,* Report of EEI Committee on Economic Growth, Pricing and Energy Use, Executive Summary, June 1975. These forecasts are based on growth in real GNP of 3.7 percent.

[6]Murray Weidenbaum, "Future Capital Requirements of the Electric Utility Industry 1974-80," *Public Utilities Fortnightly,* January 30, 1975, p. 15.

[7]Construction work in progress is not depreciable. Thus, the percentage change in operating plant, or "electric plant in service" can be approximated in the following manner:

$$\text{Change in plant} = \frac{Pt - P(t\text{-}1)}{P(t\text{-}1)}$$

$$= \frac{P(t\text{-}1) + C(t\text{-}n) - dP(t\text{-}1) - P(t\text{-}1)}{P(t\text{-}1)}$$

$$= \frac{C(t\text{-}n) - dP(t\text{-}1)}{P(t\text{-}1)}$$

$$= \frac{C(t\text{-}n)}{P(t\text{-}1)} - d$$

where
- Pt = electric plant in service in period t
- d = the depreciation rate, equal to a constant (3.02%)
- Ct-n = gross increase in plant in service, equal to construction expenditures in an earlier year. (In fact, the increase would be equal to some combination of the expenditures in several years.) With construction expenditures growing at a rate of over 17 percent, new additions would have to be 20 percent of existing capacity for electric plant in service and therefore, depreciation to grow at the same rate.

Table 2

SOURCES OF FUNDS — CLASS A AND B PRIVATELY OWNED ELECTRIC UTILITIES

a) Including the Allowance for Funds Used During Construction (AFC)

	Net Income Less Dividends	Depreciation	Deferred Taxes	Investment Tax Credit	Total of Internal Funds	Common and Preferred Stock[1]	Long-Term Debt[2]	Notes	Total of External Funds	Total All Funds
1972 Millions of Dollars	1,233	2,896	343	185	4,658	4,824	4,845	132	9,801	14,459
Percent	8.5	20.2	2.3	1.2	32.2	33.3	33.5	.9	67.7	100.0
1971 Millions of Dollars	1,026	2,628	196	90	3,939	3,900	4,770	136	8,806	12,745
Percent	8.0	20.6	1.5	.7	30.9	30.5	37.4	1.0	69.0	100.0
1970 Millions of Dollars	886	2,399	110	25	3,420	2,780	4,866	(104)	7,542	10,962
Percent	8.0	21.8	1.0	.2	31.1	25.3	44.3	(.9)	68.8	100.0
1969 Millions of Dollars	884	2,203	94	67	3,249	1,246	3,552	845	5,643	8,891
Percent	9.9	24.7	1.0	.7	36.5	14.0	39.9	9.4	63.4	100.0
1968 Millions of Dollars	797	2,034	75	81	2,987	1,048	3,161	481	4,680	7,676
Percent	10.3	26.4	.9	1.0	38.9	13.6	41.1	6.2	61.0	100.0
1967 Millions of Dollars	842	1,894	56	78	2,869	736	2,630	427	3,794	6,662
Percent	12.6	28.4	.8	1.1	43.0	11.0	39.4	6.4	56.9	100.0
1966 Millions of Dollars	810	1,774	49	60	2,694	512	2,226	186	2,924	5,617
Percent	14.4	31.5	.8	1.0	47.9	9.1	39.6	3.3	52.0	100.0
1965 Millions of Dollars	716	1,675	51	60	2,503	376	914	348	1,638	4,141
Percent	17.3	40.3	1.2	1.4	60.4	9.1	22.1	8.4	39.6	100.0
1964 Millions of Dollars	712	1,575	65	61	2,412	495	957	52	1,504	3,916
Percent	18.2	40.2	1.7	1.6	61.6	12.6	24.4	1.3	38.4	100.0

b) Excluding The Allowance for Funds Used During Construction (AFC)

	Net Income Less Dividends	Less AFC	Depreciation	Deferred Taxes	Investment Tax Credit	Total of Internal Funds	Common and Preferred Stock[1]	Long Term Debt[2]	Notes	Total of External Funds	Total
1972 Millions of Dollars	1,233	(1,069)	2,896	343	185	4,658	4,824	4,845	132	9,801	13,390
Percent	1.2		21.6	2.5	1.3	26.8	36.0	36.1	.9	73.1	100.0
1971 Millions of Dollars	1,026	(812)	2,628	196	90	3,127	3,900	4,770	136	8,806	11,933
Percent	1.7		22.0	1.6	.7	26.2	32.6	39.9	1.1	73.7	100.0
1970 Millions of Dollars	886	(588)	2,399	110	25	2,031	2,780	4,866	(104)	7,542	10,374
Percent	2.8		23.1	1.0	.2	27.2	26.8	46.9	(1.0)	72.7	100.0
1969 Millions of Dollars	884	(403)	2,203	94	67	2,846	1,246	3,552	845	5,643	8,489
Percent	5.6		25.9	1.1	.7	33.5	14.6	41.8	9.9	66.4	100.0
1968 Millions of Dollars	797	(275)	2,034	75	81	2,712	1,048	3,161	481	4,689	7,402
Percent	7.0		27.4	1.0	1.0	36.6	14.1	42.7	6.4	63.3	100.0
1967 Millions of Dollars	842	(186)	1,894	56	78	2,682	736	2,630	427	3,794	6,476
Percent	10.1		29.2	.8	1.1	41.4	11.3	40.6	6.5	58.5	100.0
1966 Millions of Dollars	810	(128)	1,774	49	60	2,566	512	2,226	186	2,924	5,490
Percent	12.4		32.3	.8	1.0	46.7	9.3	40.5	3.3	53.2	100.0
1965 Millions of Dollars	716	(94)	1,675	51	60	2,409	376	914	348	1,638	4,048
Percent	15.4		41.4	1.3	1.5	59.5	9.3	22.6	8.6	40.4	100 0
1964 Millions of Dollars	712	(85)	1,575	65	61	2,327	495	957	52	1,504	3,831
Percent	16.4		41.1	1.7	1.6	60.7	12.9	25.0	1.3	39.2	100.0

Note: Sums may not equal totals due to rounding.

[1]Common and preferred stock equals change in proprietary capital minus net income less dividends. This differs slightly from the change in proprietary capital less the change in retained earnings, because of the conversion of retained earnings into stock.

[2]Net of retirements and refinancings.

Source: Federal Power Commission, *Statistics of Privately Owned Electric Utilities in the United States*. Calculated from summary tables.

Table 3

DEPRECIATION AND AMORTIZATION AS A PERCENT OF ELECTRIC PLANT IN SERVICE
—CLASS A AND B PRIVATELY OWNED ELECTRIC UTILITIES

	Electric Plant in Service[1] ($ mill.)	Percent Change Electric Plant in Service (Percent)	Depreciation and Amortization ($ mill.)	Depreciation and Amortization as Percent of Electric Plant in Service (Percent)
1972	$94,055	9.5	$2,896	3.07(3.04)[2]
1971	85,883	8.8	2,628	3.05(3.03)[2]
1970	78,937	8.5	2,399	3.03(3.03)[2]
1969	72,765	7.9	2,203	3.02
1968	67,408	7.7	2,034	3.01
1967	62,605	6.7	1,894	3.02
1966	58,649	5.7	1,774	3.02
1965	55,490	5.4	1,675	3.01
1964	52,638		1,575	2.99

[1]Average of current and previous year. Does not include nuclear fuel.

[2]Includes nuclear fuel.

Source: Federal Power Commission, *Statistics of Privately Owned Electric Utilities in the United States*.

since construction work in progress is not depreciable, construction expenditures are converted to operating plant only with a lag of several years, and consequently fall short of current expenditures because of inflation and the growth in demand.

However, over the next few years the decline in the contribution of depreciation should be arrested. Projections of future capacity needs are being revised downward and inflation appears to be abating. While these factors are being offset by the shift to more capital intensive technologies and environmental requirements, the growth in construction expenditures should still be less than in the past. As mentioned previously, EEI projects an average rate of increase of 10 percent. At the same time the additions to operating plant are now a substantial percentage of total plant (12 percent in 1972)[8] and are likely to increase as construction work in progress continues to come on line at the very high growth rates of the recent past.

The share of new capital funding represented by retained earnings also fell dramatically--from 18 percent in 1964 to 8.5 percent in 1972. While construction expenditures have grown at a very rapid rate, common equity increased only 8 percent per year, in part reflecting increased reliance on debt and preferred stock. At the same time the rate of return on equity has declined slightly; so that the growth in earnings has fallen far behind the increase in funding needs.

The most commonly cited explanation for the decrease in the rate of return in the late sixties is the very high rate of inflation coupled with the use of historic cost figures for rate-setting purposes. The rates which a utility is allowed to charge are usually designed to yield a desired rate of return given historic costs, plus known future increases. Estimates of increased cost based on projections of inflation are only now receiving acceptance. In the early sixties these procedures worked to the utilities' advantage, for the low rates of inflation were more than offset by growing demand and increased exploitation of economies of scale. However, as inflation accelerated and the opportunities for production efficiencies were exhausted, this was no longer true and an increasing number of utilities have been unable to realize their allowed rates of return. The problem was exacerbated in 1974 with the fall-off in demand brought about by conservation efforts and the recession.

This decline in the role of retained earnings has been made even more significant by the rapid growth in the costs of financing construction. In 1964 the cost of borrowed and equity funds used for construction purposes was only 2 percent of total construction costs. By 1972, reflecting rising interest rates and longer construction lead times they were over 7 percent and absorbed 87 percent of retained earnings (Table 2(b)). With these costs taking up a growing share of internal funds, the utilities must resort to more external financing in order to construct a plant of given capacity and cost exclusive of borrowing charges.

[8] FPC, *Statistics of Privately Owned Electric Utilities in the United States*: net addition to electric plant in service plus depreciation.

Also, although these costs must be met out of current income during the construction period, there are no offsetting revenues, for construction work in progress is not included in the rate base. Instead, the cost of financing construction is considered part of the total costs of the project and is added to the rate base when the facility is completed. Also an addition is made to nonoperating income so that nominal earnings are not depressed during construction by the appearance in the income statement of what are really capital expenditures. However, this addition, known as allowance for funds used during construction (AFC), is merely a bookkeeping entry and does not represent cash revenues.

This treatment of construction work in progress and the cost of financing construction affects earnings in several ways. First, as Appendix A demonstrates, the addition of AFC to the rate base after the plant is completed does not completely offset the failure to include work in progress during the construction period, and thus creates a discrepancy between allowed and realized rates of return. Also, as long as the utility continues to build, there will be a gap between nominal and actual cash earnings. Since most utilities' construction programs do not end with the completion of a single plant, it is possible that actual earnings will never catch up with nominal earnings.

Secondly, the use of AFC can mean considerable volatility in reported earnings. When a project goes into commercial operation AFC is automatically eliminated; however, to include the newly completed plant in the rate base requires a hearing. Given regulatory lags this may mean a period of some months during which earnings are abnormally low because there is no AFC and also no increase in rates to reflect the addition of the new plant.

Lastly, severe cash flow difficulties may develop. Most purchasers of utility stock are looking for income rather than appreciation; so that utilities pay out approximately 70 percent of their common earnings in dividends. The addition of AFC may give the appearance that earnings are sufficient to support dividend payments while cash flow is inadequate. For example, Savannah Electric and Consolidated Edison both failed to meet dividend payments primarily because they did not have the cash revenues. Earnings *appeared* to cover historic dividend rates, but an important element of these earnings was the noncash AFC. Other companies face this same problem to a lesser degree, and are able to maintain dividends only by borrowing.

External Financing

a) *Common Stock.* As the utilities have become more dependent on external funding sources, the market has grown unreceptive to new issues. In 1974 almost all the utilities' common stock sold below book value. For the 71 major utilities that do not have substantial nonelectricity revenues, the median ratio of price to book value was .77. For only ten utilities was the ratio above one.[9]

Utilities are understandably loathe to issue stock at such a time, for to do so dilutes the value of the existing shareholder's investment and consequently his potential earnings. Moreover, repeated dilutions will be perceived by the market, which will then further discount the price of the stock.

In 1974 skyrocketing fuel costs, plus cutbacks in demand, caused many utilities' earnings to fall.[10] In addition, Consolidated Edison's failure to pay its second quarter dividend threw into question the value of utility stocks as a stable source of income, and at the same time interest rates on all forms of debt reached record levels, offering the investor seeking income many attractive alternatives to utility stocks. However, despite these unique features it would be a mistake to view the financing difficulties of the utilities as a problem of recent origin.

Chart I compares the ratio of market price to book value[11] for Moody's utility composite with that for industrials. Since 1965 there has been a steady downward trend for utilities in contrast with an erratic but only slight decline for industrials.

As Table 4 shows, econometric analysis indicates that this marked deterioration in the ratio of price to book value is largely explained by the decline in the return to equity relative to the yield on alternative investments, represented here by Aaa industrial bonds. Coverage ratios have also had a significant influence, probably because the market views them as a measure of the riskiness of the investment. Chart II compares the actual values for the ratio of price to book value (p/B-1) with the fitted values produced by equation (2). The closeness of the fit suggests that much of the fall in stock prices in 1974 was the culmination of a downward trend in utility prices brought about by the decline in relative earnings and decreasing coverage ratios. Certainly, there were unusual and hopefully nonrecurring problems in 1974; but these precipitated a financial crisis which may well have come in any case.

b) *Long-Term Debt and Preferred Stock.* While the prospect of issuing common stock in 1974 was generally unattractive, alternatives were

[9]These are all the utilities analyzed by *Valueline* except those which derived more than 30 percent of revenues from nonelectricity sources, according to the FPC *Statistics of Privately Owned Electric Utilities.* An important exception to this exclusion is the New England Gas and Electric Association which receives substantial revenues from gas operations, but is still included. The eight largest New England companies are in the sample and all the regions are well represented except the East-South Central states which are supplied largely by the publicly owned Tennessee Valley Authority.

[10]Forty-two of the 71 utilities experienced declines in reported earnings per share in 1974. Source: *Valueline.*

[11]The ratio for year t is the market price for year t divided by the book value per share as of December 31 of (t-1).

Table 4

REGRESSION TO EXPLAIN THE DECLINE IN MARKET PRICE RELATIVE TO BOOK VALUE

1. $$\frac{p}{B-1} = \underset{(49.26)}{0.891}\,\frac{E-1}{R} - \underset{(-1.93)}{0.921}\,\frac{N}{C-1}$$

$\bar{R}^2 = 0.955$

INTERVAL: 1962-1973; annual data

2. $$\text{Log}\,\frac{p}{B-1} = \underset{(-3.07)}{-1.024} + \underset{(3.21)}{0.678}\,\log\frac{E-1}{R} + \underset{(2.37)}{0.939}\,\log \text{COV-1}$$

$\bar{R}^2 = 0.942$; normalized $\bar{R}^2 = 0.956$

INTERVAL: 1962-1973, annual data

where:

	p	is the average market price of Moody's 24 utilities.
	B	is the average book value of the 24 utilities.
	E	is the rate of return to common equity for investor-owned utilities.
	N	is the volume of new stock issues for investor-owned utilities.
	C	is the value of common equity for investor-owned utilities.
	COV	is the coverage ratio, or earnings before interest and income taxes divided by interest, for investor-owned utilities.
	R	is the yield on Aaa industrial bonds.

A more complete description of these equations appears in Appendix B.

Chart I

RATIOS OF MARKET PRICE TO PER SHARE BOOK VALUE
MOODY'S INDUSTRIAL AND UTILITY AVERAGES

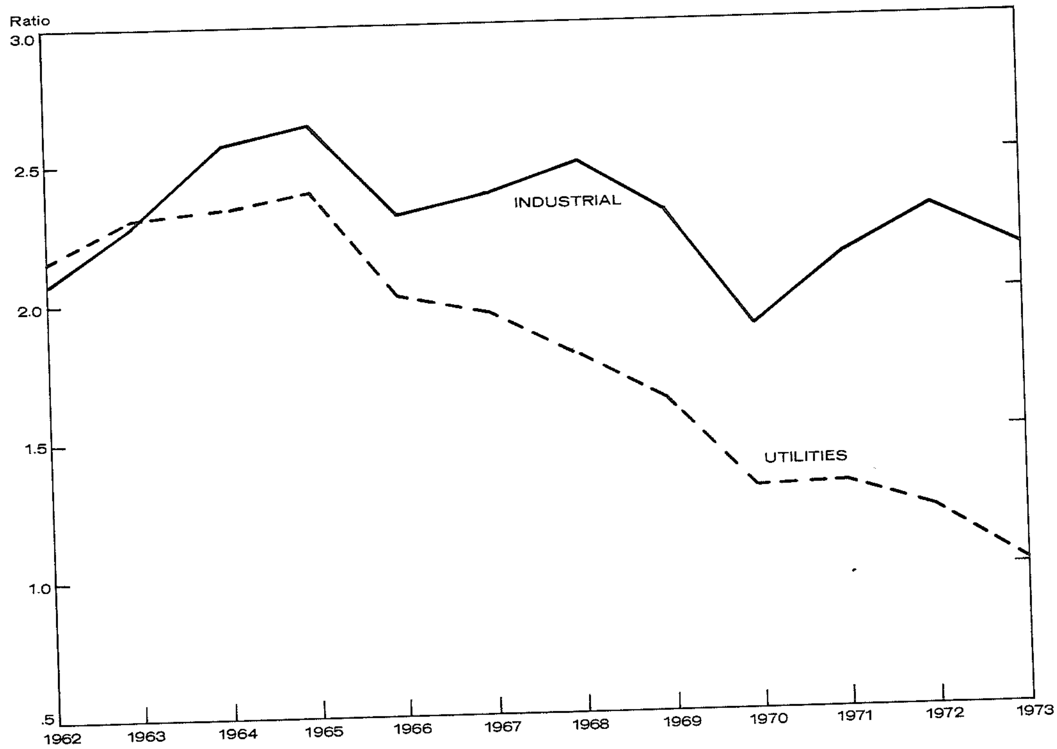
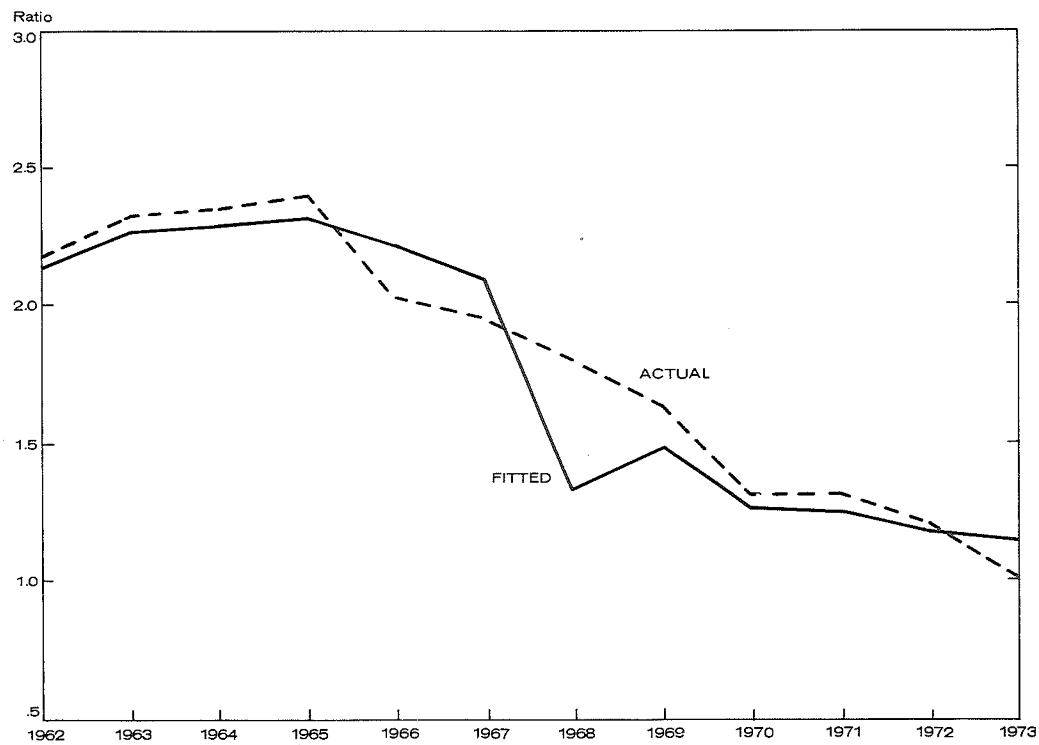


Chart II

COMPARISON OF ACTUAL AND FITTED VALUES
OF THE RATIO OF MARKET PRICE TO BOOK VALUE FOR MOODY'S UTILITY AVERAGE



limited. Many utilities found that, as a result of declining earnings and rising interest costs, the coverage requirements of bond indentures and preferred stock provisions had become binding constraints.

Bond indentures typically preclude the issuance of new senior debt if net earnings available for interest fall below twice the annual bond interest, including that on the bonds to be issued; similarly, additional preferred stock may not be issued if available earnings are less than 1 1/2 times annual interest charges and preferred stock dividends.

A good measure of the strength of these restrictions is the coverage ratio, or the ratio of earnings before interest and income taxes to interest charges. In 1967 the average coverage ratio for the 71 major utilities was 5.02; by 1973, 2.96. For nine utilities it was below 2.2; and for three, less than 2.[12] While comparable data for 1974 were not available at the time of writing, it is evident that there has been further deterioration: in 1973 the ratio of operating income to interest was 2.59 for the 71 firms; in 1974, 2.2.[13]

Many utilities have been further constrained by a high degree of leverage. In 1974 the ratio of common equity to total capitalization was below 32 percent for 15 of the 71 utilities, less than 30 percent for five firms.[14] These low ratios reflect the fact that equity is the most costly source of funds. However, the market views suspiciously utilities with less than 30 percent of their total capital in common equity. In addition, bond indentures and preferred stock provisions usually restrict common dividends if the share of common equity falls below 25 percent and limit the issuance of new bonds to no more than 60 percent of additional property. Consequently, firms with low equity ratios must balance large sales of bonds or preferred stock with issues of common stock. However, as we have seen, 1974 was a most inopportune time for such offerings.

Also, the record yields on fixed income securities in 1974 were themselves a strong deterrent to new issues of bonds and preferred stock, particularly since many utilities viewed these as temporary and were unwilling to be locked into such high cost debt for a long period. In 1974 the average yield on Moody's new Aa utility bonds was 9.41 percent, compared to 7.83 percent in 1973 and the previous high of 8.74 in 1970.[15]

These problems have been exacerbated by the declining fortunes of the primary purchasers of preferred stock — the corporate investor, particularly the insurance companies. Because of regulatory lags and the failure to take adequate account of the effects of inflation on claims, the multi-line companies are experiencing sharp declines in operating earnings. To

[12]Calculated from *Moody's Public Utility Manual,* 1974.

[13]Source: *Valueline,* Spring 1975.

[14]*Valueline.*

[15]Data Resources Inc., *The Data Resources Review.* Also in 1974 the yield on preferred stock like that on long-term debt reached a record level. For the year it averaged 9.17 percent, and for several months exceeded 10 percent. Salomon Brothers, *An Analytical Record of Yields and Yield Spreads,* January, 1975.

offset this the industry is seeking to bolster investment income. This has increased the demand for corporate bonds, notes and debentures — although apparently not those of the utilities — and has greatly slowed the rate of acquisition of preferred stock.

II. The New England Experience

Recent Difficulties — Restrictions on Debt and Preferred Stock

In general, the experience of the eight largest New England utilities during the recent crisis has paralled that of the industry. The problems are similar to those faced elsewhere, but somewhat more severe. Since July 1973, four of these New England companies have had their bond ratings lowered by Moody's and one small firm's rating was temporarily withdrawn (Table 5). In addition, 4 of the 18 electric utilities removed from the lists of legal investments for savings banks in Connecticut, Massachusetts, New Hampshire, and New York were New England companies.[16]

These changes are, of course, costly. By the end of 1974 the spread between Moody's Aaa and Baa utility bonds was 208 basis points; and one New England subsidiary company derated to Baa in December 1974 paid 13 1/8 percent on bonds sold the following month! Since then the gap has narrowed; but as of the end of September it was still 170 points.[17]

High interest rates, together with a massive construction program and declining earnings, have seriously eroded the coverage ratios of the New England utilities. In 1967 the average ratio of earnings before taxes and interest charges to interest for the eight largest New England firms was 4.58. By 1973 it had fallen 50.2 percent to 2.28 (Table 6). The utilities' own calculations show further deterioration in 1974, with the result that several firms were unable to issue additional long-term debt or preferred stock. Construction programs were maintained with bank loans and commercial paper, usually at rates in excess of 11 percent. Others retained the option of issuing senior securities, at least temporarily, only because they were permitted to change accounting practices so as to defer the recording of fuel expenses and accrue unbilled revenues. These changes did not increase cash flow but raised reported earnings and consequently legal coverage ratios.

Largely because of such difficulties, short-term borrowing reached unusual proportions in 1974, ranging from 10.8 percent of total capitalization to 83 percent. In 1970 the range was from .4 to 22.8 percent with only three firms in excess of 10 percent.[18]

[16]Removals were taken from *Moody's Public Utility News Reports* from July 1974-May 1975. For Connecticut, removals were recorded for the period 6/30/74-3/31/75; for Massachusetts, 4/1/74-3/1/75; for New Hampshire, 5/31/74-3/31/75 and for New York, 7/1/73-7/1/74. These are the only states with such lists.

[17]*Moody's Public Utility News Reports,* January 7, 1975 and October 7, 1975.

[18]Total capitalization is usually defined as long-term debt and equity. It does not include short-term debt. Calculations were made from company prospectuses.

Table 5

MOODY'S PUBLIC UTILITY NEWS REPORTS
BOND RATINGS
REVISIONS SINCE JULY 13, 1973

Downward Revisions	From	To
1973.4		
Duke Power Mortgages	Aa	A
Debentures	A	Baa
*Boston Edison	Aa	A
1974.1		
Consolidated Edison	A	Baa
— Edison Electric Illum.	Aa	A
— Kings County Elec. Light and Power	Aa	A
— Staten Island Edison	A	Baa
— Yonkers Electric Light and Power	A	Baa
— Westchester Lighting	A	Baa
**Public Service Co. of New Hampshire*	A	Baa
1974.2		
*Northeast Utilities		
*— Western Massachusetts	Aa	A
Baltimore Gas and Electric Mgt.	Aaa	Aa
Deb.	Aa	A
Detroit Edison	Aa	A
Columbus and Southern Ohio Electric	Aa	A
Iowa Electric Light and Power	Aa	A
*Central Vermont Public Service	suspended	
Consolidated Edison	suspended	
— Edison Electric Illum.	suspended	
— Kings County Elec. Light and Power	suspended	
— Staten Island Edison	suspended	
— Yonkers Electric Light and Power	suspended	
Savannah Electric and Power Mgt.	A	Baa
Deb.	Baa	Ba
American Electric Power Co.		
— Ohio Power Co. Mgt.	A	Baa
Deb.	Baa	Ba
Citizens Utilities	A	Aa
*Eastern Utilities Assoc.	Baa	Ba
*— Blackstone Valley Gas and Electric	A	Baa
*— Brockton Edison	A	Baa
*— Fall River Electric and Light	A	Baa
Delmarva Power and Light	Aa	A
*Boston Edison	A	Baa
Virginia Electric and Power Mgt.	Aa	A
Deb.	A	Baa
1974.3		
**Northeast Utilities*		
*— Hartford Electric Light	Aa	A
*— *Connecticut Light and Power*	Aa	A
Ohio Edison	Aaa	Aa
— *Pennsylvania Power Co.*	Aa	A
Florida Power Corporation Mgt.	Aa	A
Deb.	A	Baa
Detroit Edison	A	Baa
1974.4		
Philadelphia Electric Mgt.	Aa	A
Deb.	A	Baa
Dayton Power and Light	Aa	A
Cincinnati Gas and Electric	Aaa	Aa
Florida Power and Light	Aa	A
San Diego Gas and Electric Mgt.	Aa	A
Deb.	A	Baa
**Northeast Utilities*		
*— Western Massachusetts	A	Baa
Southern Company		
— Georgia Power	A	Baa
Consumers Power Mgt.	A	Baa
Deb.	Baa	Ba
1975.1		
Savannah Electric and Power	suspended	
Southern Company		
— Georgia Power	suspended	
American Electric Power		
— Appalachian Power Mgt.	A	Baa
Deb.	Baa	Ba
Arizona Public Service	A	Baa
Houston Lighting and Power Mgt.	Aaa	Aa
Deb.	Aa	A
American Electric Power		
— Indiana and Michigan Elec. Mgt.	A	Baa
Deb.	Baa	Ba
Union Electric	Aa	A
Carolina Power and Light	A	Baa
Iowa Electric Lighting and Power	A	Baa
Cleveland Electric Illum.	Aaa	Aa
American Electric Power		
— American Gas and Electric	A	Baa
Pacific Power and Light	A	Baa
San Diego Gas and Electric Mgt.	A	Baa
Deb.	Baa	Ba
Upward Revisions		
1973.4		
*Cape and Vineyard Electric	A	Aa
1974.1		
Public Service of New Mexico	A	Aa
1974.4		
*Central Vermont Public Service	reinstated	Baa
1975.2		
Consolidated Edison	reinstated	Baa
— *Edison Electric Illum.*	reinstated	Baa
— Kings County Electric Lighting and Power	reinstated	Baa
— *Staten Island Edison*	reinstated	Baa
— Westchester Lighting	reinstated	Baa
— Yonkers Electric Lighting and Power	reinstated	Baa

*Asterisks denote New England companies.

Table 6

AVERAGE COVERAGE RATIOS 1967-1973

	New England	United States	New England as a Percent of U.S.
1967	4.58	5.02	91
1968	4.01	4.56	88
1969	3.35	4.07	82
1970	2.75	3.37	82
1971	2.61	3.17	82
1972	2.92	3.22	91
1973	2.28	2.99	76

Note: The New England figure is the unweighted average for the eight largest companies; the U.S. figure is the average for the sample of 71, including the eight New England firms.

Source: Calculated from earnings statements in *Moody's Public Utility Manual.*

However, although the existence of such extensive short-term debt is usually a symptom of financial difficulties, it cannot be taken as proof. Most of the New England firms finance on-going construction on a short-term basis. These notes are then converted to stocks and bonds according to market conditions and company needs. Consequently, New England's construction program, which averaged $640 million per year from 1970 through 1974,[19] would by itself have resulted in a substantial increase in the average balance of short-term liabilities.

Moreover, as discussed earlier, the record interest levels of 1974 may have prompted firms to borrow short in order to avoid being locked into very high cost long-term debt, and at least one firm chose to issue notes in order to defer a long-term offering until a new facility came on line. It was the firm's belief that the market would respond favorably to the new plant's operation by allowing a lower interest rate on a pending mortgage issue.

Nonetheless, a number of large companies had no alternative to short-term borrowings if they were to maintain their construction programs, and in hearings before the FPC and state regulatory agencies the need for higher rates to generate revenues sufficient to maintain coverage ratios has been a central argument.

Primarily because of rate increases, in some cases subject to refund, and the elimination of lags in the fuel adjustment formulas, coverage difficulties for most firms have been temporarily alleviated. At the time of writing one large utility was unable to meet its preferred stock provisions and the subsidiary of another was still limited entirely to short-term financing, but most companies either had issued or expected to issue senior debt in 1975.

This cannot, however, be taken as a sign of any permanent improvement. The ratios of earnings to fixed charges are likely to be little better in 1975 than they were in 1974 and unless rate increases keep pace with rising costs, the difficulties of the past year will certainly be repeated.[20]

Several of the New England firms have been further restricted by the low share of common equity in total capitalization. In both 1973 and 1974 the average common equity ratio for the eight largest New England companies was 33 percent.[21] With 30 percent considered a floor, this means that major issues of either long-term debt or preferred stock should be

[19]Calculated from the prospectuses of the eight firms.

[20]Indeed, coverage restrictions have become almost a chronic problem for the New England companies. Several subsidiary companies could not meet earnings requirements for new bonds as early as 1970, while another was precluded from issuing both bonds and preferred stock in late 1971 and early 1972.

[21]In addition, the subsidiaries of one of the firms with a higher equity ratio (35.6 percent in 1974) have unusually restrictive bond indentures: long-term debt may not exceed 50 percent of total capitalization. Thus, although leverage is not very great, bond issues must still be accompanied by increased equity.

balanced by a sale of common shares. However, all of the companies' stock sold well below book value in 1974 and continued to do so throughout the first half of 1975.

Restrictions on Issues of Common Equity

In 1974 the average ratio of market price to book value for the eight largest New England utilities was .69, substantially lower than a national average for the 71 companies of .83.[22] Six of the eight firms were in the lowest 25 percent of the distribution.[23] This situation has subsequently improved; but as of September 30, 1975, the average ratio of price to book value was still only 0.76 for the eight New England companies.[24]

As was done for the industry as a whole, it can be shown statistically that the ratios of price to book value for individual utilities are largely determined by the return to equity relative to the yield on alternative investments (Table 7). Coverage ratios, the percentage change in common shares, and the dividend payout ratio are also significant, although lesser factors. The importance of the payout ratio is particularly interesting for it supports the contention that the buyers of utility stock are interested in income rather than appreciation, and it justifies the utilities' efforts to maintain dividends despite declining earnings.

The poor performance of New England utility stocks is therefore primarily attributable to low earnings which have depressed both rates of return and coverage ratios. For several firms this effect has been intensified by issues of common stock. However, as Appendix C describes in more detail, it also appears that the market discounts the New England companies' stock somewhat more than the financial variables warrant. This discount appears in part related to perceptions of regulatory climate, for a premium is placed on the stock of utilities in Texas and Oklahoma where regulation is minimal.

Pressures on Earnings

a) *Construction.* While New England utilities have shared in the general industry problems of inflation, regulatory lags, and rising interest costs, a big factor underlying both the region's relatively low earnings and its need for capital has been its construction program. Even by industry

[22]This is the average ratio of the 1974 market price to book value per share as of December 31, 1973. Calculated from *Valueline.*

[23]The ratio of price to book value for the New England firms has in fact been below the national average since the mid-sixties. In 1965 the average for New England was only 70 percent of the average for the 71 firms. Since that time there has been a convergence, with New England reaching 87 percent of the national average in 1973. However, 1974 marked a reversal of this trend with the New England figure dropping to only 83 percent; moreover, the significance of this gap is undoubtedly much greater than in the past, since in 1974 both ratios were below one.

[24]*Wall Street Journal,* October 1, 1975. Market prices were divided by book values as of December 31, 1974.

Table 7

REGRESSION TO EXPLAIN THE DECLINE IN MARKET PRICE RELATIVE TO BOOK VALUE

These regressions use time series data pooled over the 71 utilities. *ci* designates multiple constants. The individual values are listed in Appendix C.

INTERVAL — 1965-1974

1. $$\frac{P}{B-1} = ci + 1.039 \frac{E}{R}$$
$$(55.77)$$

$\bar{R}^2 = .81$

Ratio of mean absolute error to average ratio of price to book value:

New England $\frac{.196}{1.368} = .14$ U.S. $\frac{.194}{1.731} = .11$

INTERVAL — 1968-1974

2. $$\frac{P}{B-1} = ci + 1.205 \frac{E}{R} + .062 \text{ COV-1} - 0.811 \text{ NS} + 1.124 \text{ PO}$$
$$(24.34) \quad (5.19) \quad (-4.75) \quad (10.21)$$

$\bar{R}^2 = 0.74$

Ratio of mean absolute error to average ratio of price to book value:

New England $\frac{.106}{1.218} = .087$ U.S. $\frac{.144}{1.454} = .099$

3. $$\frac{P}{B-1} = ci + 1.834 \frac{D}{R} + .057 \text{ COV-1} - 0.567 \text{ NS}$$
$$(25.35) \quad (4.80) \quad (3.33)$$

$\bar{R}^2 = 0.75$

Ratio of mean absolute error to average ratio of price to book value:

New England $\frac{.089}{1.218} = .073$ U.S. $\frac{.136}{1.454} = .094$

Variables:

p — market price of common shares.
B — book value per share as of December 31.
E — the rate of return to equity as reported.
D — ratio of dividends to equity as reported.
R — yield on Moody's Aaa industrial bonds.
PO — payout ratio
COV — coverage ratio
NS — percentage change in common shares (has not been multiplied by 100%).

All variables except R and COV have been calculated from data contained in *Valueline*. COV has been calculated using *Moody's Public Utility Manual*.

-1 designates a lag of 1 year.

standards this has been substantial, reflecting both a major modernization effort and a high proportion of more costly nuclear capacity.[25] From 1968 through 1974 investor-owned utilities in New England accounted for 5.67 percent of capital expenditures by all investor-owned utilities in the contiguous United States. (Table 8).[26] Capacity on the other hand, was only 4.8 percent of the national total in 1973; generation, 4.95 percent.[27]

To finance this construction program the New England utilities have borrowed heavily. Between 1970 and 1974 the long-term debt of the eight largest firms rose 40 percent, from $2.2 billion to $3.1 billion, and notes payable almost tripled from $.36 billion to $.97 billion. At the same time approximately $180 million in bonds bearing interest rates of 2, 3, and 4 percent matured, having to be refinanced at rates of 8 percent or more.[28]

This tremendous expansion in debt at high rates has sent interest costs soaring. From $126 million in 1970 they more than doubled to $283 million in 1974. During the same period income before interest charges, including the allowance for funds used during construction, increased 88 percent; so that the share of gross income absorbed by interest rose from 44.5 percent to 52.9 percent.[29] Coverage ratios plummetted. For individual utilities these changes were even more striking. For one company the proportion of gross income going to interest rose from 50.9 percent to 74.8 percent, exhausting the entire dollar increase in gross income and sharply lowering the rate of return to equity.

Such an extensive construction program also means that a large proportion of capital is tied up in work in progress, which is not included in the rate base and generates no return. For the eight companies, work in progress in 1974 accounted for over 16 percent of total property, plant and equipment, and ranged from a low of 5.2 percent to a high of 32.9 percent.[30]

[25]In 1968, 33 percent of the steam capacity of New England's A and B privately owned utilities was in units of 500 or more megawatts (MW); 30 percent in units of 300 MW or less. Some 8 percent of steam capacity came from nuclear plants. By 1973, 59 percent of steam capacity was in units of greater than 500 MW and 22 percent in units of 300 MW or less. Twenty-five percent of steam capacity was nuclear power. Source: New England Regional Commission, *A Study of the Electric Power Situation in New England, 1970-1990*, and calculated from National Coal Association, *Steam-Electric Plant Factors, 1974*.

[26]*Electrical World, Annual Statistical Report*, March 1969, 1970, 1971, 1972, 1973, and 1974.

[27]Edison Electric Institute, *Statistical Year Book for 1973*.

[28]*Moody's Public Utility Manual*, 1969.

[29]These are weighted averages, the weights being each utility's income before interest. The simple averages for 1970 and 1974 are 44.7 and 55.3, respectively. Figures are calculated from annual reports in *Moody's Public Utility Manual* and prospectuses.

[30]The weighted average of work in progress to property, plant and equipment was 16.5 percent; the unweighted average, 16.1 percent. The figures do not include investments in joint nuclear projects, which are carried at equity value. If these were included, the figures would be 16.1 percent and 15.8 percent respectively, and the range from 4.8 to 32.5 percent. All figures are as of December 31, 1974 except for the Public Service Company of New Hampshire which is for July 31, 1974.

Table 8

CAPITAL EXPENDITURES OF INVESTOR-OWNED UTILITIES

UNITED STATES AND NEW ENGLAND

	United States ($ mill.)	New England ($ mill.)	New England/ United States (Percent)
1968	$ 7,139.8	$ 400.6	5.6
1969	8,289.0	495.0	6.0
1970	10,144.8	688.1	6.8
1971	11,893.7	681.5	5.7
1972	13,385.4	772.4	5.8
1973	14,907.4	838.2	5.6
1974	17,087.7	825.9	4.8
Total	$82,847.8	$4,701.7	5.7

Source: *Electrical World*

As demonstrated in Appendix A, the exclusion of work in progress from the rate base causes a permanent reduction in the actual return to equity. It also means that a significant share of the New England companies' earnings is accounted for by the allowance for funds used during construction, which of course is not cash income.

Since utilities typically have high dividend payout ratios and feel compelled to maintain dividends even when earnings fall, the combination of the allowance for funds used during construction and depressed earnings may mean that firms are unable to generate sufficient cash income to cover their dividends. Indeed, after deducting the allowance for funds used in construction and non-cash accounting changes, five of the eight New England companies had earnings in 1974 which fell short of dividend payments. In one case the funds available were only 23 percent of the dividends actually declared! Yet for none of these utilities did dividends exceed nominal earnings.

Regardless of the specific source of funds, this means that the utilities were in effect, borrowing to maintain their dividends. Given the apparent importance attached to dividends by the market, this may well be the appropriate decision. However, the added interest costs mean either higher rates for the consumer or a further squeeze on earnings.

b) *The Energy Crisis.* In mid-1973 the price of residual oil was $4.50-$5.00 per barrel; in 1974 over $13.00. While national prices increased in a similar fashion the impact on costs was much greater in New England because of the region's heavy dependence on oil. In 1973 approximately 68 percent of the generation by investor-owned utilities in New England was from oil-fired plants compared to 18 percent for the Nation, and 38 percent in the Mid-Atlantic states, the next most dependent region.[31] Individual New England utilities ranged from a 30 percent dependence on oil to as high as 91 percent.[32]

To a large degree the earnings of the New England companies have been protected from the direct effects of the increase in oil prices. At the time of the crisis all the major companies had automatic fuel adjustment clauses permitting them to pass fuel costs on to the consumer. Protection was not complete, for the clauses operated with lags of one or two months; and with the rapid rise in prices, revenue shortfalls and cash flow difficulties developed. However, most of the impact of these lags on reported earnings, although not cash flow, has been eliminated. In 1974 almost all firms were permitted to change accounting practices so as to defer the recording of fuel expenses until the month in which they are billed

[31] The percent of fossil fuel was taken from the Edison Electric Institute's *Statistical Yearbook, 1973* and the proportion of fossil fuel accounted for by oil from National Coal Association, *Steam-Electric Plant Factors 1974.* The latter weights are actually for all generations, not merely investor owned; however, the differences appear insignificant.

[32] *Valueline,* Spring 1975.

to the consumer. Several of the subsidiaries of one company actually are allowed to bill fuel costs currently, thereby avoiding the cash flow difficulties of any future price increase as well as maintaining earnings.

The energy crisis also affected the utilities indirectly, for the high electric bills and the crisis atmosphere led to substantial conservation efforts and reductions in energy consumption. These cutbacks were then augmented by the recession which has severely curtailed industrial usage. Since the electric rates charged are based on projections of demand, these unusually low consumption levels have caused revenues to fall below expectations, further depressing earnings and realized rates of return.

In this regard the New England experience has been somewhat worse than the rest of the country. Nationally there was no growth in energy consumption in 1974, while in New England electric output fell 2.3 percent.[33] Moreover, the impact of these cutbacks has varied considerably among the individual utilities. One New England firm actually registered a slight increase in sales, while another experienced a decline of 9 percent.

Future Prospects

Despite the generally gloomy picture described thus far, the prospects for the New England utilities are not entirely bleak. Moreover, there is a great deal of variation among the individual companies.

As mentioned above, changes in accounting practices now protect reported earnings from future increases in the cost of fuel, although a substantial rise in prices could still cause cash flow difficulties. The New England firms are further shielded from cost increases by rate agreements which permit the pass-through of the costs of purchased power. This is significant because a substantial portion of total generation in New England is supplied under wholesaling arrangements which are not subject to normal regulatory proceedings. In 1973 approximately 17 percent of total generation was supplied by jointly owned companies selling only to their owner utilities. At the time these companies, which are really only plants, began operations, the terms of sale were approved by the relevant regulatory agencies. These contracts call for each owner to pay a share of all costs inclusive of a pre-determined return to capital so that increases in costs are automatically passed on to the buyer, and through the purchased power clause to the consumer. Also, most of the power for two utilities is supplied by wholesale subsidiaries, the rates for which are set by the Federal Power Commission. Since the Federal Power Commission must make a decision within five months or allow the requested rates to go into effect subject to refund, and since four of the six state agencies take considerably longer for their deliberations, this arrangement means that a sizable share of costs can be recovered from customers in a relatively timely

[33]This decline followed increases of 8.5 percent and 5.3 percent in the preceding two years. Source: Edison Electric Institute, *Electric Output,* January 1974 and January 2, 1975.

fashion. In this regard New England is probably better protected than other regions, although the significance of these arrangements varies considerably among the individual firms.

The problem caused by the fall-off in demand should also abate. Although electric output in New England showed no growth in the first half of 1975, much of this is attributable to the effects of the recession on industrial usage. National figures for July show sales to industrial customers down 6.3 percent from the preceding year but commercial and residential consumption some 7 percent higher.[34] As the economy revives, industrial usage should pick up. In addition demand forecasts have been revised downward so that rates will be based on more realistic estimates of sales. NEPLAN, the planning agent of the New England utilities, has forecast annual load growth of 6.4 percent over the next ten years.[35] A year ago they were projecting growth of 7.5 percent.

Most importantly the uncertainties of the demand situation, reinforced by financing difficulties, have led the New England companies to reassess their construction programs. Eight major units scheduled between 1975 and 1985, with a total capacity of 9,406 megawatts (MW) have been deferred at least one year. Two of these units have been postponed five years, with two more units totalling 1500 MW put off indefinitely. These postponements should ease the financial strains considerably, but only compared to what they would otherwise have been. *Valueline* has estimated that the capital expenditures of the eight largest firms in 1975 will be approximately 3 percent above the 1974 level, and company prospectuses indicate that average expenditures in 1976 and 1977 will be more than 30 percent above those in 1974.[36]

Moreover, these expenditures will be spread unevenly among the eight utilities, with four firms accounting for all of the increase. The need for outside capital will be even more varied: the companies with large construction programs tend to be those generating the smallest proportion of funds internally. In part, this occurs because the completion of a plant increases depreciation and cash revenues, as well as reducing the need for additional construction.[37]

Nonetheless, as a region New England is in an improved position relative to the rest of the Nation, with more flexibility in scheduling future capacity additions. Some 1040 MW of new capacity were added in 1974

[34]Edison Electric Institute, *Electric Output,* October 11, 1975.

[35]New England Power Planning, *New England Load and Capacity Report,* March 1, 1974 and April 1, 1975.

[36]This includes the cost of financing construction. Rates of 9 percent are now being used to calculate AFC.

[37]For two Massachusetts companies the recent completion of large plants together with revised projections of future load growth means that more than 50 percent of construction expenditures over the next three or four years is expected to be financed from internal funds. As indicated in the industry section, this is very unusual and is certainly not representative of all of New England.

and another 2530 MW are expected in 1975. Together, these additions represent a 20 percent increase over 1973 capacity and as a result, NEPLAN estimates that there will be a reserve of more than 50 percent above the 1975 winter peak.[38] This is unusually high. The standards for reliability set by the Northeast Power Coordinating Council, to which all large New England utilities belong, imply reserve requirements over the next ten years of only 20 to 25 percent. Moreover, for the Nation as a whole, reserves were only 20 percent of the peak from 1966 through 1973.[39]

With so much capacity having just come on line, New England will require relatively fewer additions in the near future than the rest of the country. For the five years 1976 through 1980, *Electrical World* estimated in mid-1974 that the investor-owned companies in New England would complete projects with a total capacity of 5289 MW. This is 4.0 percent of the additions then planned for all investor-owned utilities,[40] and is substantially below the region's share of capacity[41] and recent construction levels. Moreover, the bulk of New England's new capacity was to have come on line in 1979 and 1980, while national additions were spread relatively evenly over the period.

To some extent, the reduced rate of construction in New England will be offset by the high proportion of planned nuclear capacity — 66 percent, compared to 35 percent for the Nation.[42] Work by Arthur D. Little indicates that a nuclear plant is likely to cost more than 50 percent more per kw than comparable coal-fired capacity. An oil-fired plant, on the other hand, is approximately 10 percent less costly than coal.[43] Applying these relationships to the proposed capacity mixes indicates that it will cost New England at least 14 percent more than the Nation per additional kw. Consequently, 4 percent of national capacity is equivalent to a minimum of 4.5 percent of construction expenditures. This is still well below

[38]New England Planning, *New England Load and Capacity Report 1974-1985,* April 1, 1975.

[39]Federal Power Commission, *Electric Power Statistics,* December 1973.

[40]Additions were calculated from scheduled projects contained in National Coal Association, *Steam-Electric Plant Factors,* 1974. They do not take account of recent deferrals, since they were compiled from the October 15, 1974 issue of *Electrical World.*

[41]Investor-owned utilities in New England accounted for 4.8 percent of U.S. investor-owned capacity in 1973, 4.95 percent of generation. Figures include Alaska and Hawaii. Source: EEI *Statistical Yearbook for 1973.*

[42]This refers to the investor-owned component only.

[43]Arthur D. Little, Inc./S. M. Stoller Corporation, *Economic Comparison of Base-Load Generation Alternatives for New England Electric,* March 1975. The Arthur D. Little study estimates that for capacity scheduled for 1983 and 1985 nuclear would cost approximately 53 percent more per kw than coal. If scrubbers were required the gap would be less than 25 percent. Converting these figures to constant dollars increases the gap in the no-scrubber case to 57 percent.

its recent share and if coal plants are required to add the very costly sulphur dioxide scrubbing equipment, the gap between per kw capital costs will be greatly reduced, as New England presently plans no new coal capacity.[44]

Because these figures do not take account of all recent cancellations and deferrals, New England's share of construction expenditures which actually take place may be very different. However, these estimates probably provide a better indication of New England's relative *need* for new capacity than a figure net of all cancellations; although to the extent that demand projections have been revised downward, the magnitude of the proposed expenditures is too great.[45]

Policy Implications

The current financial difficulties of the electric utility industry are attributable to inadequate earnings relative to the returns available from alternative investments, coupled with substantial on-going capital requirements. Unlike other industries, electric utilities feel that they have little flexibility in deciding whether and when to build. Thus they must continue to seek financing even when the market is unfavorable. The fall-off in demand brought on by the energy crisis and the recession, while aggravating the earnings situation, has provided a much needed breathing space. However the problem remains: it is merely a question of whether it must be faced now or at a later date.

The difficulties of the New England utilities are essentially those of the rest of the industry, intensified by an unusually large construction program and problems associated with the energy crisis. Fortunately, the conclusion of a major phase of construction leaves a number of New England firms in a relatively strong position at the moment compared to their own recent experience and the rest of the industry. However, for the region capital requirements remain as great as ever.

The policy implications of this are clear. If the Nation and the region are to have an assured supply of electric energy for the future, realized rates of return for the utilities must be made competitive with those on other investments. This can be accomplished in a number of ways; the most direct being for regulatory agencies to raise allowed rates of return. However, a first step should be to enable the utilities to realize the returns they are presently allowed. Rate should be based on cost estimates that take account of inflation or at least use year-end figures rather than historic costs. Also, the period between the filing of the rate request and the decision should be reduced or if this does not permit thorough analysis, a

[44]These figures do not take account of the fact that New England's plants will be built later and therefore will incorporate more inflation. The region's share of historic construction expenditures is discussed earlier.

[45]Ideally one would like comparisons of future needs to exclude deferrals made because of finances. Unfortunately the distinction is usually unclear.

further adjustment to earnings can be made to account for inadequate revenue throughout the period of deliberation.[46]

Increasing cash flow will also affect earnings through lower interest costs as well as directly reducing the need for outside funding. One proposal favored by several New England utilities calls for the inclusion of construction work in progress in the rate base as well as the normalization of investment tax credits and liberalized depreciation in those states which do not now permit this.

Allowing the utilities to achieve reasonable rates of return is not incompatible with the need to protect the consumer. Regulatory agencies have a responsibility for ensuring an adequate supply of electricity as much as for holding down its cost. While recent cutbacks in plant construction are largely justified by revised projections of demand, particularly here in New England, further postponements could create future shortages. In this regard, agencies might explore the implications of treating most favorably the companies with the greatest external capital needs. Alfred Kahn of the Public Service Commission of New York has suggested this,[47] and it receives some support from the regressions presented in this paper. However, such a practice could become a reward for poor management and for failure to explore the possibilities of load management. Also, if it is continued over a period at several years, the market will recognize that rates of return tend to fall after construction is completed and will discount the stock appropriately.

Lastly, the regulator is not relieved of his obligation to scrutinize costs and where possible to press for greater efficiencies. In particular, he should question very closely the projections of future demand since this is now an area of great uncertainty, and the cost of excess capacity is very high. It may even be appropriate to reconsider traditional assumptions about reliability and desired capacity reserves. If anything, the need for effective regulation has increased, but a given of such regulation must be that the utilities receive adequate rates of return.

Will the utilities be able to raise capital in future? Regulatory agencies must find the rate of return at which the answer is yes.

[46]In an inflationary period the use of historic test years plus long rate procedures can mean sub-par earnings for two years or more, even if the regulatory body accedes to the request.

[47]The Honorable Alfred E. Kahn, "Between Theory and Practice: Reflections of a Neophyte Public Utility Regulator," *Public Utilities Fortnightly,* January 2, 1975.

Appendix A

Effect of Present Treatment of Work in Progress

Regulatory commissions in setting rates attempt to establish a composite rate of return on plant in service which will generate sufficient funds to allow a reasonable return on equity. However, with construction expenditures increasing rapidly the failure to include work in progress in the rate base means that equity holders will not realize their allowed return unless the overall rate is continually revised.

A plant is to be built with a cost of C excluding the cost of funds used during construction. All funds are assumed to be acquired at the beginning of the construction period (in fact funds would be added over time as needed). The plant begins operation at the end of year n.

For simplicity it is assumed that the plant effectively lasts forever with depreciation being offset by continual reinvestment.

If r is the allowed rate of return on equity, the equity investor would expect a stream of income with a present value of

$$V_1 = \frac{rweC}{x}$$

where we is the share of equity in the plant[48]
x is the discount rate.

With work in progress included in the rate base this would in fact occur. If r^* is the total composite return on capital, the stream of income before interest charges and income taxes would be

$$R^* = \frac{r^*C}{x}$$

and the return to equity

$$\frac{rweC}{x} = \frac{r^*C - iwdC - t(r^*C - iwdC)}{x}$$

where r^* is the total composite rate of return to capital before taxes.
i is the rate of interest on the debt component of C.
wd is the share of C accounted for by debt.
t is the income tax rate.

[48]Preferred stock has not been included in the analysis but could be added with no change in the conclusion.

Under present procedures however, there would be no stream of income from the investment until the plant became operable in the year n+1. (AFC is a noncash addition to income). At that time the cost of funds used during construction (AFC) would be included in the rate base. The value of AFC in any year before the plant is operative is:

$$r^1 C \text{ where } r^1 = rweC + iwdC$$

(r^* differs from r^1 by the inclusion of taxes).
Thus in year (n+1) the rate base would be $C + nr^1C$ and the value of the stream revenues available to pay the total cost of capital would be:

$$R^{**} = \frac{r^*(C + nr^1 C)}{x(1 + x)^n}$$

With regulation the composite return r^1 should be equal to the discount rate x, the marginal cost of capital for the firm; and in fact the actual rates being used to calculate AFC are those one would choose as discount rates. For the major New England utilities the rate r^1 in 1974 was usually 8 percent, and has now been increased to 9 percent. Thus:

$$R^{**} = \frac{r^*(C + nr^1 C)}{x(1 + x)^n} = \frac{r^*C(1 + nx)}{x(1 + x)^n}$$

In addition, the current approach increases the return to equity during the construction period by reducing taxes. Even though AFC is not considered taxable income, the interest costs of funds used for construction are still considered an expense for tax purposes.

The value of this reduction in taxes is

$$\sum_{y=1}^{n} \frac{tiwdC}{(1 + x)^y} = \frac{tiwdC}{x} - \frac{tiwdC}{x(1 + x)^n}$$

The value of the return to equity under this approach is

$$V_2 = \underset{(1)}{\frac{r^*(C + nxC)}{x(1 + x)^n}} - \underset{(2)}{\frac{iwdC}{x}} - \underset{(3)}{\frac{t(r^*(C + nxC) - iwdC)}{x(1 + x)^n}} + \underset{(4)}{\frac{tiwdC}{x}} - \underset{(5)}{\frac{tiwdC}{x(1 + x)^n}}$$

where term (1) is the total stream of revenues available to pay interest charges, taxes and the return to equity.
(2) is the interest costs of the project, which are incurred from the beginning even though revenues do not appear until n+1.
(3) is the taxes paid on revenues from the project.
(4)(5) represent the tax savings from expensing interest costs during the period of construction.

Thus

$$V_1 - V_2 = \frac{r^*C}{x} - \frac{iwdC}{x} - \frac{t(r^*C - iwdC)}{x}$$

$$- \left[\frac{r^*C(1 + nx)}{x(1 + x)^n} - \frac{iwdC}{x} - \frac{t(r^*C\,(1 + nx) - iwdC)}{x(1 + x)^n} \right.$$

$$\left. + \frac{tiwdC}{x} \cdot \frac{tiwdC}{x(1 + x)^n} \right]$$

$$= \frac{r^*C(1 - t)}{x} - \frac{r^*C(1 - t)(1 + nx)}{x(1 + x)^n}$$

$$> 1, \text{ since } \frac{(1 + nx)}{(1 + x)^n} < 1$$

as long as $n > 1$

Thus the value of the return to equity is less with the current treatment of AFC than if work in progress were in the rate base.

Appendix B

The market price of a stock should be closely related to the stream of expected earnings per share discounted by the opportunity cost of capital. Thus:

$$p_o \approx \frac{e_1}{(1+r_o)} + \frac{e_2}{(1+r_o)^2} + \frac{e_3}{(1+r_o)^3} + \ldots\ldots. \qquad (1)$$

where: p_o is the average market price in year t = o, the present
e_t is the earnings per share in year t
r_o is the discount rate

If one assumes that $e = e_1 = e_2 \ldots. e_n \ldots.$ then

$$p_o \approx \frac{e}{r_o} \qquad (2)$$

Investors will have varying expectations concerning the growth in earnings per share; but it seems that they would be aware of the earnings of the preceding year and the dilution that results from the current issue. Thus:

$$p_t \approx \frac{\dfrac{E(t-1)}{m(t-1) + \dfrac{N_t}{p_t}}}{r_t} \qquad (3)$$

where: E(t—1) is the actual earnings available for common in year t—1
m(t—1) is the number of shares outstanding at the end of t—1
Nt is the dollar amount to be raised in year t; so that Nt/pt is the *number* of new shares.

Equation (3) can be manipulated to produce:

$$p_t \approx \frac{\dfrac{E(t-1)}{m(t-1)}}{r_t} - \frac{N_t}{m(t-1)} \qquad (4)$$

Dividing through by b(t—1), the book value per share at the end of year t—1, one gets:

$$\frac{p_t}{b(t-1)} \approx \frac{\dfrac{E(t-1)}{m(t-1) \cdot b(t-1)}}{r_t} - \frac{N_t}{m(t-1) \cdot b(t-1)} \qquad (5)$$

Equation (5) shows the ratio of market price to book value as a positive function of (a) the return on equity relative to the opportunity cost of capital and negatively related to (b) the dollar volume of new issues relative to the book value of existing equity.

Equation (5) was tested for the period 1962 through 1973, with the results below.

$$\frac{p}{B-1} = 0.891 \frac{E-1}{R} - 0.921 \frac{N}{C-1}$$
$$\qquad (49.26) \qquad\qquad (-1.93)$$

$\bar{R}^2 = 0.955$
DW = 0.94

INTERVAL: 1962-1973; annual data.

where:

p	is the composite market price for Moody's 24 utilities. Source: *Moody's Public Utility Manual,* 1974.
B—1	is the book value per share (excluding reserves for deferred Federal income taxes and investment tax credits) for Moody's 24 utilities, lagged one year.
E—1	is the return to common equity for A and B investor owned utilities, lagged. Source: Federal Power Commission, *Statistics on Privately Owned Electric Utilities in the United States.*
R	is the yield on Moody's Aaa industrial bonds.
N	is the dollar volume of new public utility stock issues. This includes preferred and therefore is only a proxy for new common issues. Source: *Moody's Public Utility Manual* for A and B investor-owned utilities.
C—1	value of common equity, lagged. Source: Federal Power Commission, *Statistics of Privately Owned Electric Utilities in the United States.*

An alternative formulation assumes that the return to equity is modified by the investor's perception of the risk of the investment. To approximate this risk factor the coverage ratio was used. This is the ratio of earnings before interest charges and income taxes divided by interest. The lower this ratio, the greater the risk. The source was the Federal Power Commission, *Statistics on Privately Owned Electric Utilities in the United States*. The equation was estimated in logarithmic form over the interval 1962 through 1973.

$$\mathrm{Log}\left(\frac{P}{B-1}\right) = \underset{(-3.07)}{-1.024} + \underset{(3.21)}{0.678}\ \mathrm{Log}\left(\frac{E-1}{R}\right) + \underset{(2.37)}{0.939}\ \mathrm{Log}\,(\mathrm{COV}\text{-}1)$$

$\bar{R}^2 = 0.942$; normalized $\bar{R}^2 = 0.956$

DW = 1.34; normalized DW = 1.36

Appendix C

Regressions to Explain the Decline in Market Price Relative to Book Value — Individual Utilities

These regressions use time series data pooled across the 71 utilities. In such regressions the observations are values for a number of utilities, each over several years. The key assumption is that the same relationships hold both among firms and over time. Several variations are possible. In the simplest version one assumes the identical relationship for all firms and employs a single constant. The form of the regression in this case is:

Yit = a + bXit

where Yit is the dependent variable for utility i at time t. Xit is the independent variable for utility i at t. a and b are the same for each utility. Alternatively one may try to take account of systematic variation among the utilities with individual constants, essentially dummy variables. Thus:

Yit = ai + bXit

It is also possible to perform a version of generalized least squares, which in addition to having multiple constants also considers the possibility of correlation among the error terms, implying that what happens to one firm influences the performance of another. When tried, these produced results very similar to those in the multiple constant version. The same variables were significant but their coefficients were closer to those in the simple single constant version and the explanatory power of the equations was slightly reduced.

The hypothesis was that the ratio of price to book value is primarily a function of the relationship between the return to equity and the yield on alternative investments, as represented by interest rates. Because it is generally thought that purchasers of utility stocks are interested more in income than in appreciation, the possibility that dividends rather than earnings are viewed as the "return" was also considered. Coverage ratios were introduced to represent a measure of perceived risk, with low values indicating both general poor health of the company and the possibility that dividends might be skipped. Finally, because information on desired equity funding was not available, the percentage increase in shares was used to take account of any saturation effects and fears of earnings dilution.

The best equations appear in Table 7 of the article and are starred in this appendix. In general, the versions with multiple constants and current values of the independent variables perform most successfully.[49] However,

[49] The percentage change in shares used currently may introduce a slight bias. However this variable functions primarily as a dummy and has almost the same coefficient and significance when used currently as when it is lagged.

all variations support the hypothesis that the return to equity relative to the yield on alternative investments is the key determinant of the ratio of market price to book value.

For each equation the mean absolute error was calculated for the New England firms and found to be approximately the same percentage of the average ratio of price to book value as for the entire sample. Thus conclusions based on these regressions are valid for the New England region as well as for the industry. These ratios appear under each equation.

Lastly, it is interesting to note that in all these equations the individual constants for the New England firms are somewhat below the industry average. This suggests that the market discounts these stocks somewhat more than the financial variables warrant. While this discount may be related to size, it also seems to reflect perceptions of regulatory climate. Utilities in Texas and Oklahoma where regulation is minimal have relatively large constants indicating that the market pays a premium for their stocks.

Equations

* — indicates preferred equation. These appear in Table 7 of the article.
ci — designates multiple constants. These are listed after each equation.

The individual utilities are identified.

INTERVAL 1965-1974

1) $$\frac{P}{B_{-1}} = \underset{(-7.16)}{-0.370} + \underset{(42.29)}{1.036}\left(\frac{E\#}{R}\right)_{-1}$$

$\bar{R}^2 = 0.72$

Ratio of mean absolute error to average ratio of price to book value:

New England $\frac{.236}{1.368} = .17$ U.S. $\frac{.300}{1.731} = .17$

2) $$\frac{P}{B_{-1}} = ci + \underset{(47.34)}{.975}\left(\frac{E\#}{R}\right)_{-1}$$

$\bar{R}^2 = 0.76$

Ratio of mean absolute error to average ratio of price to book value:

New England $\frac{.179}{1.368} = .13$ U.S. $\frac{.208}{1.731} = .12$

Utility	Mean Absolute Error	Constant	Utility	Mean Absolute Error	Constant
PBVBSE	0.09750	—0.31623	PBVDTE	0.18411	—0.38405
PBVCTP	0.19630	—0.43534	PBVIPL	0.26542	—0.44421
PBVEUA	0.26968	—0.38231	PBVOEC	0.21197	—0.36901
PBVNES	0.12917	—0.33501	PBVPIN	0.18103	—0.04344
PBVNEG	0.17563	—0.36731	PBVSIG	0.24747	—0.63643
PBVNU	0.18356	—0.35097	PBVTED	0.14526	—0.40310
PBVPNH	0.16961	—0.46334	PBVWPC	0.22998	—0.41740
PBVUIL	0.21298	—0.49831	PBVWPWR	0.16121	—0.40087
PBVAYP	0.17383	—0.47481	PBVIPW	0.16486	—0.33370
PBVATE	0.20449	—0.17404	PBVIOP	0.20825	—0.47038
PBVCNH	0.19982	—0.48661	PBVIUTL	0.19167	—0.52114
PBVED	0.15797	—0.29246	PBVKLT	0.11855	—0.43771
PBVDQU	0.17004	—0.46931	PBVMPL	0.12812	—0.56958
PBVGPU	0.21775	—0.38906	PBVNSP	0.09752	—0.39947
PBVLIL	0.17395	—0.28340	PBVOTTR	0.18010	—0.55142
PBVNGE	0.17411	—0.48122	PBVSAJ	0.13939	—0.47494
PBVPPL	0.13748	—0.39767	PBVUEP	0.16826	—0.32147
PBVPE	0.17379	—0.28259	PBVEDE	0.16086	—0.41084
PBVBGE	0.20252	—0.33248	PBVKU	0.15422	—0.48348
PBVCPL	0.35659	0.09031	PBVCEL	0.32572	0.25377
PBVDEW	0.23604	—0.23924	PBVCSR	0.26943	0.13817
PBVDUK	0.27263	0.09317	PBVHOU	0.35313	0.45690
PBVFDP	0.32299	0.15047	PBVOGE	0.21525	0.13648
PBVFPL	0.33294	0.26136	PBVSPS	0.29399	0.14654
PBVPOM	0.15890	—0.32692	PBVTXU	0.26178	0.48294
PBVSAV	0.15054	—0.29151	PBVTGE	0.28978	—0.15150
PBVSCG	0.16181	—0.03990	PBVAZP	0.18091	—0.12910
PBVSO	0.17228	—0.05637	PBVIDA	0.19711	—0.20003
PBVTE	0.42534	0.52790	PBVNVP	0.34836	—0.01720
PBVVEL	0.30778	—0.02394	PBVPNM	0.28556	—0.28957
PBVAEP	0.27892	—0.06054	PBVSRP	0.31763	0.01046
PBVCER	0.18416	—0.40806	PBVUTP	0.13107	—0.39787
PBVCIP	0.17780	—0.46716	PBVPPW	0.19372	—0.29183
PBVCVX	0.26664	—0.50526	PBVPGN	0.15690	—0.39057
PBVCWE	0.15092	—0.21976	PBVPSD	0.10617	—0.26477
			PBVSCE	0.15465	—0.26807

3)* $\frac{P}{B-1} = ci + 1.039 \frac{E}{R}$

$$(55.77)$$

$\bar{R}^2 = 0.81$

Ratio of mean absolute error to average ratio of price to book value:

New England $\frac{0.196}{1.368} = 0.14$ U.S. $\frac{0.194}{1.731} = 0.11$

Utility	Mean Absolute Error	Constant	Utility	Mean Absolute Error	Constant
PBVBSE	0.08702	—0.35527	PBVDTE	0.12518	—0.38497
PBVCTP	0.19658	—0.44433	PBVIPL	0.18097	—0.46950
PBVEUA	0.33055	—0.36931	PBVOEC	0.20919	—0.38037
PBVNES	0.12558	—0.38261	PBVPIN	0.19097	—0.13946
PBVNEG	0.20048	—0.41988	PBVSIG	0.18071	—0.75218
PBVNU	0.15837	—0.40630	PBVTED	0.14393	—0.46384
PBVPNH	0.19774	—0.52032	PBVWPC	0.19869	—0.46825
PBVUIL	0.27066	—0.59387	PBVWPWR	0.17730	—0.45365
PBVAYP	0.11451	—0.49458	PBVIPW	0.11411	—0.31560
PBVATE	0.26798	—0.26215	PBVIOP	0.12833	—0.51597
PBVCNH	0.16852	—0.49436	PBVIUTL	0.13759	—0.60822
PBVED	0.12116	—0.32670	PBVKLT	0.10248	—0.43569
PBVDQU	0.17678	—0.52604	PBVMPL	0.11333	—0.57124
PBVGPU	0.12478	—0.37571	PBVNSP	0.06811	—0.43601
PBVLIL	0.13868	—0.32940	PBVOTTR	0.17474	—0.58874
PBVNGE	0.17797	—0.50185	PBVSAJ	0.16529	—0.48796
PBVPPL	0.12518	—0.47707	PBVUEP	0.10662	—0.32857
PBVPE	0.12526	—0.32398	PBVEDE	0.13721	—0.42617
PBVBGE	0.11194	—0.42505	PBVKU	0.19476	—0.47746
PBVCPL	0.37263	0.07696	PBVCEL	0.37400	0.14090
PBVDEW	0.23998	—0.28904	PBVCSR	0.21351	0.06521
PBVDUK	0.24345	0.08684	PBVHOU	0.30499	0.42812
PBVFDP	0.26351	0.11035	PBVOGE	0.13390	0.09127
PBVFPL	0.36102	0.20356	PBVSPS	0.34935	0.09490
PBVPOM	0.17529	—0.38379	PBVTXU	0.24853	0.41644
PBVSAV	0.09905	—0.30438	PBVTGE	0.30660	—0.25553
PBVSCG	0.14180	—0.05513	PBVAZP	0.29645	—0.19763
PBVSO	0.18604	—0.10262	PBVIDA	0.16686	—0.27332
PBVTE	0.43756	0.47571	PBVNVP	0.34314	—0.09144
PBVVEL	0.33836	—0.06634	PBVPNM	0.26646	—0.35372
PBVAEP	0.29869	—0.13033	PBVSRP	0.32249	—0.05859
PBVCER	0.10676	—0.43423	PBVUTP	0.09214	—0.46481
PBVCIP	0.16567	—0.44379	PBVPPW	0.14546	—0.33509
PBVCVX	0.16652	—0.44085	PBVPGN	0.12044	—0.44726
PBVCWE	0.12631	—0.22798	PBVPSD	0.11727	—0.34838
			PBVSCE	0.19048	—0.35327

INTERVAL 1968-1974, 497 observations

$$4)\quad \frac{p}{B-1} = ci + .720\left(\frac{E^{\#}}{R}\right)_{-1} + .070\ \text{COV-1} - 0.806\ \text{NS-1} + 0.731\ \text{PO-1}$$

(12.35) (3.93) (-2.95) (5.54)

$\bar{R}^2 = 0.58$

Ratio of mean absolute error to average ratio of price to book value:

New England $\frac{.144}{1.218} = .118$ U.S. $\frac{.183}{1.454} = .126$

Utility	Mean Absolute Error	Constant	Utility	Mean Absolute Error	Constant
PBVBSE	0.10149	—0.64003	PBVDTE	0.17174	—0.68792
PBVCTP	0.10721	—0.78505	PBVIPL	0.22558	—0.69581
PBVEUA	0.16346	—0.70795	PBVOEC	0.17595	—0.76809
PBVNES	0.12454	—0.64740	PBVPIN	0.14691	—0.44927
PBVNEG	0.14633	—0.65024	PBVSIG	0.16074	—0.80002
PBVNU	0.19872	—0.58080	PBVTED	0.10065	—0.64978
PBVPNH	0.17202	—0.64229	PBVWPC	0.16688	—0.71408
PBVUIL	0.13683	—0.74980	PBVWPWR	0.16706	—0.69935
PBVAYP	0.19517	—0.65964	PBVIPW	0.10721	—0.69758
PBVATE	0.17715	—0.45528	PBVIOP	0.15687	—0.79679
PBVCNH	0.11696	—0.74280	PBVIUTL	0.17572	—0.85849
PBVED	0.12847	—0.64587	PBVKLT	0.09054	—0.73937
PBVDQU	0.16117	—0.63247	PBVMPL	0.10346	—0.77118
PBVGPU	0.13829	—0.60637	PBVNSP	0.11198	—0.63445
PBVLIL	0.16281	—0.57002	PBVOTTR	0.10007	—0.80254
PBVNGE	0.11605	—0.69121	PBVSAJ	0.10408	—0.68785
PBVPPL	0.11372	—0.59335	PBVUEP	0.13028	—0.61797
PBVPE	0.10897	—0.59817	PBVEDE	0.12992	—0.67544
PBVBGE	0.16643	—0.64603	PBVKU	0.16634	—0.84154
PBVCPL	0.21716	—0.37537	PBVCEL	0.37564	—0.00119
PBVDEW	0.17844	—0.58158	PBVCSR	0.25927	—0.22958
PBVDUK	0.23594	—0.34126	PBVHOU	0.38132	0.12863
PBVFDP	0.34703	—0.13392	PBVOGE	0.20250	—0.22864
PBVFPL	0.29284	0.00613	PBVSPS	0.15015	—0.39090
PBVPOM	0.13845	—0.53989	PBVTXU	0.26623	0.14633
PBVSAV	0.15063	—0.57247	PBVTGE	0.21878	—0.40924
PBVSCG	0.23058	—0.32936	PBVAZP	0.09572	—0.41895
PBVSO	0.16377	—0.37937	PBVIDA	0.12324	—0.49942
PBVTE	0.41389	0.16086	PBVNVP	0.34871	—0.10244
PBVVEL	0.20675	—0.38916	PBVPNM	0.23681	—0.51061
PBVAEP	0.26298	—0.32364	PBVSRP	0.36328	—0.22588
PBVCER	0.16189	—0.68208	PBVUTP	0.10213	—0.59145
PBVCIP	0.11807	—0.73581	PBVPPW	0.14721	—0.45269
PBVCVX	0.53575	—1.00129	PBVPGN	0.15059	—0.54020
PBVCWE	0.15418	—0.58881	PBVPSD	0.13361	—0.54108
			PBVSCE	0.16895	—0.53394

$$5)^{*}\quad \frac{p}{B-1} = ci + 1.205\ \frac{E}{R} + .062\ \text{COV-1} - 0.811\ \text{NS} + 1.124\ \text{PO}$$

(24.34) (5.19) (-4.75) (10.21)

$\bar{R}^2 = 0.74$

Ratio of mean absolute error to average ratio of price to book value:

New England $\frac{.106}{1.218} = .087$ U.S. $\frac{.144}{1.454} = .099$

Utility	Mean Absolute Error	Constant	Utility	Mean Absolute Error	Constant
PBVBSE	0.06709	—1.57955	PBVDTE	0.07644	—1.56155
PBVCTP	0.04861	—1.67876	PBVIPL	0.15790	—1.80135
PBVEUA	0.09954	—1.60041	PBVOEC	0.09720	—1.85154
PBVNES	0.09747	—1.57033	PBVPIN	0.12946	—1.56409
PBVNEG	0.12611	—1.56979	PBVSIG	0.09022	—1.91555
PBVNU	0.10470	—1.57146	PBVTED	0.09307	—1.75752
PBVPNH	0.09554	—1.56904	PBVWPC	0.10513	—1.56626
PBVUIL	0.20554	—1.81443	PBVWPWR	0.16235	—1.67582
PBVAYP	0.14623	—1.70177	PBVIPW	0.06592	—1.66420
PBVATE	0.19529	—1.57480	PBVIOP	0.11641	—1.79068
PBVCNH	0.12178	—1.64358	PBVIUTL	0.15885	—1.90254
PBVED	0.05893	—1.34400	PBVKLT	0.09170	—1.64276
PBVDQU	0.09517	—1.78049	PBVMPL	0.09482	—1.79124
PBVGPU	0.12510	—1.51326	PBVNSP	0.07334	—1.66949
PBVLIL	0.10169	—1.55730	PBVOTTR	0.08695	—1.72781
PBVNGE	0.09674	—1.60500	PBVSAJ	0.07548	—1.59993
PBVPPL	0.14330	—1.61386	PBVUEP	0.04999	—1.56677
PBVPE	0.09233	—1.55947	PBVEDE	0.13041	—1.72016
PBVBGE	0.10847	—1.65990	PBVKU	0.13143	—1.75579
PBVCPL	0.19892	—1.27562	PBVCEL	0.36984	—1.21010
PBVDEW	0.09462	—1.60485	PBVCSR	0.17633	—1.38291
PBVDUK	0.12653	—1.19147	PBVHOU	0.23823	—0.89580
PBVFDP	0.27552	—1.12857	PBVOGE	0.13678	—1.40401
PBVFPL	0.26274	—0.94869	PBVSPS	0.12244	—1.69672
PBVPOM	0.20073	—1.40377	PBVTXU	0.18736	—0.91524
PBVSAV	0.06634	—1.51545	PBVTGE	0.17665	—1.41230
PBVSCG	0.17361	—1.31783	PBVAZP	0.18489	—1.33303
PBVSO	0.15567	—1.34530	PBVIDA	0.12087	—1.46508
PBVTE	0.41096	—0.80804	PBVNVP	0.33727	—1.02955
PBVVEL	0.18575	—1.31021	PBVPNM	0.22978	—1.47267
PBVAEP	0.20366	—1.50422	PBVSRP	0.29394	—1.20377
PBVCER	0.06844	—1.65446	PBVUTP	0.07266	—1.51371
PBVCIP	0.08583	—1.74718	PBVPPW	0.08552	—1.48316
PBVCVX	0.32139	—1.96714	PBVPGN	0.10842	—1.55724
PBVCWE	0.09097	—1.56370	PBVPSD	0.12461	—1.38326
			PBVSCE	0.20731	—1.40324

$$6)\quad \frac{P}{B-1} = ci + 1.193 \left(\frac{D}{R}\right)_{-1} + 0.058\ \text{COV-1} - 1.046\ \text{NS-1}$$

$$\qquad (15.25) \qquad\qquad (3.64) \qquad\qquad (-4.12)$$

$\bar{R}^2 = 0.61$

Ratio of mean absolute error to average ratio of price to book value:

New England $\frac{.139}{1.218} = .14$ U.S. $\frac{.175}{1.454} = .121$

Utility	Mean Absolute Error	Constant	Utility	Mean Absolute Error	Constant
PBVBSE	0.12330	—0.31365	PBVDTE	0.17922	—0.36864
PBVCTP	0.10726	—0.45912	PBVIPL	0.21088	—0.38787
PBVEUA	0.16556	—0.41115	PBVOEC	0.14823	—0.58627
PBVNES	0.12158	—0.33496	PBVPIN	0.14661	—0.19649
PBVNEG	0.15307	—0.36451	PBVSIG	0.13716	—0.19240
PBVNU	0.17174	—0.31785	PBVTED	0.09571	—0.27723
PBVPNH	0.15721	—0.29110	PBVWPC	0.11310	—0.30083
PBVUIL	0.11350	—0.42782	PBVWPWR	0.11758	—0.38217
PBVAYP	0.17247	—0.31707	PBVIPW	0.11630	—0.49121
PBVATE	0.16434	—0.17996	PBVIOP	0.13445	—0.45460
PBVCNH	0.13983	—0.30636	PBVIUTL	0.16870	—0.34208
PBVED	0.13110	—0.27440	PBVKLT	0.12013	—0.32025
PBVDQU	0.19537	—0.54013	PBVMPL	0.15292	—0.33534
PBVGPU	0.13272	—0.32127	PBVNSP	0.15789	—0.36390
PBVLIL	0.16500	—0.21630	PBVOTTR	0.13192	—0.42300
PBVNGE	0.09247	—0.34616	PBVSAJ	0.12224	—0.35147
PBVPPL	0.10845	—0.30401	PBVUEP	0.13525	—0.41899
PBVPE	0.13950	—0.40835	PBVEDE	0.16673	—0.40176
PBVBGE	0.15950	—0.30811	PBVKU	0.14999	—0.40362
PBVCPL	0.17306	—0.03529	PBVCEL	0.27692	0.27099
PBVDEW	0.15790	—0.25699	PBVCSR	0.24212	0.10471
PBVDUK	0.23337	—0.00516	PBVHOU	0.37316	0.79861
PBVFDP	0.35161	0.39101	PBVOGE	0.20958	—0.02717
PBVFPL	0.23576	0.62789	PBVSPS	0.16643	—0.29910
PBVPOM	0.20231	—0.18462	PBVTXU	0.24196	0.68376
PBVSAV	0.15185	—0.33562	PBVTGE	0.18411	0.05560
PBVSCG	0.27367	0.00134	PBVAZP	0.06523	0.02584
PBVSO	0.16593	—0.05915	PBVIDA	0.11179	—0.10788
PBVTE	0.40092	0.66878	PBVNVP	0.35603	0.58860
PBVVEL	0.18191	0.01635	PBVPNM	0.18960	0.08861
PBVAEP	0.20065	—0.13875	PBVSRP	0.35002	0.21325
PBVCER	0.16295	—0.30287	PBVUTP	0.12476	—0.14013
PBVCIP	0.12800	—0.46729	PBVPPW	0.16982	—0.20107
PBVCVX	0.36283	—0.55684	PBVPGN	0.14056	—0.23558
PBVCWE	0.16627	—0.31737	PBVPSD	0.11179	—0.14378
			PBVSCE	0.17514	—0.07275

$$7)^{*}\quad \frac{P}{B-1} = ci + 1.834\ \frac{D}{R} + 0.057\ \text{COV-1} - 0.567\ \text{NS}$$

$$\qquad (25.35) \qquad\qquad (4.80) \qquad\qquad (-3.33)$$

$\bar{R}^2 = 0.75$

Ratio of mean absolute error to average ratio of price to book value:

New England $\frac{.089}{1.218} = .073$ U.S. $\frac{.136}{1.454} = .094$

Utility	Mean Absolute Error	Constant	Utility	Mean Absolute Error	Constant
PBVBSE	0.09979	—0.92886	PBVDTE	0.09871	—0.93954
PBVCTP	0.06208	—1.08551	PBVIPL	0.17146	—1.10169
PBVEUA	0.08772	—1.05399	PBVOEC	0.08208	—1.44395
PBVNES	0.08717	—0.93923	PBVPIN	0.10866	—0.94937
PBVNEG	0.09916	—0.97688	PBVSIG	0.09768	—0.77725
PBVNU	0.09625	—0.95329	PBVTED	0.07778	—1.00352
PBVPNH	0.10139	—0.88402	PBVWPC	0.06702	—0.82973
PBVUIL	0.07645	—1.09286	PBVWPWR	0.10282	—1.05917
PBVAYP	0.13195	—0.96423	PBVIPW	0.08193	—1.18802
PBVATE	0.10629	—0.89096	PBVIOP	0.09109	—1.07259
PBVCNH	0.10471	—0.84481	PBVIUTL	0.15111	—0.95790
PBVED	0.10448	—0.64930	PBVKLT	0.08652	—0.87628
PBVDQU	0.18450	—1.32208	PBVMPL	0.05976	—0.95397
PBVGPU	0.09964	—0.92842	PBVNSP	0.08340	—1.02744
PBVLIL	0.11426	—0.85019	PBVOTTR	0.08513	—0.98850
PBVNGE	0.06379	—0.93554	PBVSAJ	0.07654	—0.92798
PBVPPL	0.09330	—0.92179	PBVUEP	0.08301	—1.03905
PBVPE	0.10548	—1.08408	PBVEDE	0.13913	—1.15121
PBVBGE	0.12589	—0.94441	PBVKU	0.10187	—0.97741
PBVCPL	0.18101	—0.62886	PBVCEL	0.21298	—0.46345
PBVDEW	0.09063	—0.90267	PBVCSR	0.17816	—0.63823
PBVDUK	0.15058	—0.58669	PBVHOU	0.29943	0.30476
PBVFDP	0.33936	—0.13834	PBVOGE	0.16491	—0.82223
PBVFPL	0.21308	0.19989	PBVSPS	0.11887	—1.23222
PBVPOM	0.26369	—0.71325	PBVTXU	0.17683	0.12772
PBVSAV	0.10319	—0.92726	PBVTGE	0.16320	—0.49002
PBVSCG	0.26247	—0.65327	PBVAZP	0.07490	—0.46999
PBVSO	0.19540	—0.67039	PBVIDA	0.09130	—0.68394
PBVTE	0.35779	0.12283	PBVNVP	0.34224	0.21017
PBVVEL	0.16248	—0.49625	PBVPNM	0.17907	—0.37196
PBVAEP	0.14282	—0.89925	PBVSRP	0.32634	—0.32691
PBVCER	0.10673	—0.93571	PBVUTP	0.08079	—0.66951
PBVCIP	0.09189	—1.18561	PBVPPW	0.05294	—0.90190
PBVCVX	0.32235	—1.32993	PBVPGN	0.08612	—0.89626
PBVCWE	0.09790	—0.98160	PBVPSD	0.07123	—0.60729
			PBVSCE	0.15359	—0.51295

Variables

p	– market price of common shares
B	– book value per share as of December 31
E	– the rate of return to equity as reported
E #	– the rate of return to equity as of December 31
D	– ratio of dividends to equity
R	– yield on Moody's Aaa industrial bonds
PO	– payout ratio
COV	– coverage ratio
NS	– percentage change in common shares (has not been multiplied by 100%)

All variables except R and COV have been calculated from data contained in *Valueline*. COV has been calculated using *Moody's Public Utility Manual*.

–1 designates a lag of 1 year.

Utilities by Region

New England

BSE	—Boston Edison
CTP	—Central Maine Power Company
EUA	—Eastern Utilities Associates
NES	—New England Electric System
NEG	—New England Gas and Electric Association
NU	—Northeast Utilities
PNH	—Public Service Company of New Hampshire
UIL	—United Illuminating Company

Mid-Atlantic

AYP	—Allegheny Power System
ATE	—Atlantic City Electric
CNH	—Central Hudson Gas and Electric Corporation
ED	—Consolidated Edison
DQU	—Duquesne Light Company
GPU	—General Public Utilities
LIL	—Long Island Lighting Company
NGE	—New York State Gas and Electric Corporation
PPL	—Pennsylvania Power and Light Company
PE	—Philadelphia Electric Company

South Atlantic

BGE	—Baltimore Gas and Electric Company
CPL	—Carolina Power and Light Company
DEW	—Delmarva Power and Light Company
DUK	—Duke Power Company
FDP	—Florida Power Corporation
FPL	—Florida Power and Light Company
POM	—Potomac Electric Power Company
SAV	—Savannah Electric and Power Company
SCG	—South Carolina Electric and Gas Company
SO	—Southern Company
TE	—Tampa Electric Company
VEL	—Virginia Electric and Power Company

East North Central

AEP	—American Electric Power
CER	—Central Illinois Light Company
CIP	—Central Illinois Public Service Company
CVX	—Cleveland Electric Illuminating Company
CWE	—Commonwealth Edison
DTE	—Detroit Edison
IPL	—Indianapolis Power and Light Company
OEC	—Ohio Edison
PIN	—Public Service Company of Indiana
SIG	—Southern Indiana Gas and Electric Company

TED	—Toledo Edison
WPC	—Wisconsin Electric Power
WPWR	—Wisconsin Power and Light Company

West North Central

IPW	—Interstate Power Company
IOP	—Iowa Power and Light Company
IUTL	—Iowa Southern Utilities
KLT	—Kansas City Power and Light Company
MPL	—Minnesota Power and Light Company
NSP	—Northern States Power Company
OTTR	—Otter Tail Power Company
SAJ	—St. Joseph Light and Power Company
UEP	—Union Electric Company
EDE	—Empire Distric Electric

East South Central

KU	—Kentucky Utilities Company

West South Central

CEL	—Central Louisiana Electric Company
CSR	—Central and South West Corporation
HOU	—Houston Lighting and Power
OGE	—Oklahoma Gas and Electric Company
SPS	—Southwestern Public Service Company
TXU	—Texas Utilities Company
TGE	—Tucson Gas and Electric Company

Mountain

AZP	—Arizona Public Service
IDA	—Idaho Power Company
NVP	—Nevada Power Company
PNM	—Public Service Company of New Mexico
SRP	—Sierra Pacific Power Company
UTP	—Utah Power and Light Company

Pacific

PPW	—Pacific Power and Light Company
PGN	—Portland General Electric Company
PSD	—Puget Sound Power and Light Company
SCE	—Southern California Edison

Discussion

John W. Weber*

The author of the paper has stated the general problem faced by utilities very accurately and very succinctly. Briefly, it is that utilities face massive capital requirements with great dependence on external funding at a time when their ability to attract needed investment funds has eroded badly.

The reasons behind the general problem were treated adequately in the paper. For background, I restate them here in the manner I like to think about them. In the mid- to late-1960s, the utility industry began to feel the combined impact of four independent trends. First and most important, the Nation's chronic inflation picked up speed. The cost of money went up dramatically, and costs — both capital and operating — skyrocketed. Second, the environmental movement began to be felt. This brought both higher capital costs and costs due to delays in getting new plants on stream. Third, the growth of electrical peak load and energy consumption accelerated and became more uncertain. The result was a spurt in requirements for additional capacity. Last, the economies of scale in building ever-larger electrical generating facilities seemed to run out, and thus ended the offset to escalating construction costs.

The result was a much more difficult environment for utilities, and the author's documentation of the general problem — particularly with respect to the New England utilities — is good. Most of the paper, however, is devoted to the problem and its documentation, not to remedies. That is not to say that no list of suggestions for solutions appears in the paper — there is such a list. But the depth of work on the remedies does not generate confidence that they will solve the problem, rather than just provide a little relief. Some groups call for government guarantee of utility debt as the solution to the problem; others call for preferential tax treatment. Are regulatory commissions the only culprit? The appropriate strategy to resolve the financing difficulties of utilities turns on the root causes of the problem, together with an understanding of the improvements possible from all quarters. The paper contributed little of that.

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Remedies Proposed

So it is on possible solutions to the well-stated problem that I want to focus this discussion. Let us consider the implications of several sets of remedies: those put forth by the author, some coming out of Washington, and perhaps some thoughts pulled together in a different way or new to at least some of you.

All but a few serious observers of the utility industry understand that the individual companies must realize greater returns and greater cash flows than they now receive. There is, of course, disagreement over how much increased return is necessary, and especially over how to obtain this increased return. But many of the observers get tangled up sorting out the various remedies, and all seem to have an aversion to stating explicitly that electric bills will increase.

The author's list of remedies is centered around making realized rates of return competitive. It is very difficult to argue with that premise. The list includes four specific suggestions:

1. Raise allowed rates of return, starting first to enable the utilities to realize the return currently allowed by their commissions;
2. Base rate structures on cost estimates that take account of inflation, or on year-end figures rather than on historic costs;
3. Reduce regulatory lag, or at least adjust target rates to account for depressed earnings during the lag period;
4. Adopt a package of two points "proposed" by the utilities: include construction work in progress in the rate base and adopt normalized accounting in states where it is not now permitted.

Now that list of remedies is interesting — particularly the one to raise allowed rates of return — and all have some degree of merit. They have not been analyzed thoroughly, but even so are not dissimilar from those coming out of Washington. Consider two more lists of remedies:

1. The list from the President's Labor-Management Committee

— Increase the investment tax credit
— Include construction work in progress in the rate base
— Depreciate construction work in progress
— Allow accelerated depreciation
— Provide deferred taxation for reinvested dividends

2. The list from the Congressional Budget Office

— Adopt a replacement cost basis for assets
— Adopt normalized accounting
— Utilize current and future test years
— Reduce regulatory lag
— Eliminate discriminatory taxing

Notice that the great bulk of these remedies — certainly all those suggested by Lynn Browne — are aimed at generating greater return and cash flows by raising the price of energy to consumers. Notice that enabling a utility to realize the allowable rate of return, basing rates on up-to-date cost figures, reducing regulatory lag, including construction work in progress in the rate base, and permitting normalized accounting are all devices that increase utility revenues or cash flows by raising the rates their customers pay for their product. Notice particularly that no one called explicitly for rate hikes — only for things whose effect is to increase the unit price of energy.

Are all of us so afraid to advocate higher energy prices that we devise schemes to do exactly that, but then couch them in moralistic terms as if we were only assuring that the rate-making formula is just and equitable? The root problem is an inadequate return on equity to utilities. Why dance around the problem with suggestions that may have unwanted side effects? Including construction work in progress in the rate base, for instance, has the effect of charging current customers for future assets that will earn in the future — current energy prices would rise; future energy prices would be lower. Because of the tax situation, the procedure would also require $2 of revenues (all borne by customers) for every $1 realized by the utilities. How much simpler the entire process of relief would be if the regulatory commissions would grant an adequate return on equity to the utilities. The commissions have come miles, but for a variety of reasons stop short of granting an adequate return.

Spectrum of Remedies

In point of fact, there are only four ways utilities can increase their realized returns:

Raising the prices charged customers for energy
Obtaining government subsidies (in one form or another)
Selling more product
Operating more efficiently

And my guess is that the most efficient program to aid our ailing utilities includes something from each of those four.

1. *Raising prices.* Utilities on balance are realizing an 11-12 percent return on equity, a figure 3 or 4 percent too low in these inflationary times when the return on riskless securities has been pushed up to 8 or 9 percent. Now if the only way to attain a more realistic return on equity for utilities is to play games with such things as construction work in progress, replacement costs, and future test years so that regulatory commissions can retain low return on investment figures, then that is what we must do. But the niggardly returns have to stop not only because investor confidence in utility equities has been eroded, but because incentives for utility managements are wrong. Why should they work hard to achieve

cost reductions when regulatory commissions pass the benefits on almost immediately to customers? Further, there are subtle pressures on utility managements to make bad capital versus operating cost decisions. Why should they invest $600 per kilowatt for an efficient baseload plant at an inadequate return when they can invest much less on a peaking unit, knowing that the higher fuel costs of the peaker can be passed through immediately?

The financial problem could, of course, be alleviated by raising rates so high that customers effectively would be suppliers of capital. But that means current customers would be subsidizing future customers. A more reasonable approach is for commissions to allow a return that assures common stock will sell approximately at book value. That point reasonably balances the interests of customers and investors alike. Then the capital markets — not governmental agencies and procedures — will deal with investment and cash flow problems for the utilities. And the cost of providing that reasonable return amounts to a one-time rate increase of only about 8 percent, so you can see why I deplore the palliatives suggested in lieu of simply raising the return on equity to a fair level.

2. *Government subsidy.* Many types of Federal government actions can improve cash flow to utilities: investment tax credit, accelerated depreciation, guarantee of debt, and the elimination of double taxation are just a few of them. To some extent they are all a form of subsidy — a word which need not be thought of as pejorative. How you come down on the matter of government subsidy depends on your ideology: whether you believe the system — particularly the capital markets — will work, or whether you believe the government must make it work. It also depends on how you feel about the tax burden to be carried by utilities: should consumers of electricity and gas pay $2 for every $1 of realized return to the utility, the other $1 going to the government? Or is some different division of that government dollar appropriate? Any device that raises rates is a "twofer," and only governmental action can change that.

A second kind of government action — kind of a reverse subsidy — can be effective in aiding utilities. Many of the suggested remedies fall clearly within the jurisdiction of the state regulatory commissions and outside the realm of the Federal government, but the Federal government can persuade the commissions to follow desired policies. For example, to the extent that normalized accounting and the inclusion of construction work in progress in the rate base are important to the utility rescue operation, the government can withhold favored tax treatment or impose an effective excise tax on utilities in states regulated by recalcitrant commissions. Thus, almost any fair and equitable slate of remedies will include some role for the government.

3. *Selling more electricity.* In this age of "energy wastrels" and the "conservation ethic," selling more electricity or gas may sound like heresy. But — assuming the electricity or gas is sold at a positive gross margin — selling more product is clearly a means open to utilities to generate more revenues and to realize higher returns. In addition, this is a path which requires no action by state regulatory commissions or by the government.

The challenge to utilities, of course, is not so much in selling more product as it is in selling "good" product. Selling off-peak electrical load, thereby improving load factor, can do wonders for profitability. It also has social and conservation benefits — for instance, using nuclear or coal-fired generating stations to supply electricity for heat storage devices that would otherwise burn gas or oil.

Any discussion of help for beleaguered utilities must consider self-help, and load factor improvement clearly falls in that category. Yet utility after utility continues to give lip service to load factor improvement without organizing to recognize this key factor to success. A high level concern for integrating all activities that affect load factor — marketing, customer education, public relations, and rate design — is still the exception throughout the industry. Improving load factor is no easy task but it is lucrative. A 1 percent improvement in load factor — which for most utilities has been deteriorating for years as growth in peak demand outpaced growth in energy sales — will increase the net income available for common stock of an electric utility about 11 or 12 percent. Such an effort is clearly worth making, and should be considered a vital, integral part of any rescue plan for utilities.

4. *More efficient operations.* A final way to increase the realized returns to utilities is to improve their operations — to make them more efficient, more effective. Improving operations implies a management process of continued performance evaluation and audit both for the large scale, relatively infrequent policy actions and for the small scale, frequent decisions made all over the organization. Many utilities have yet to formalize such a process.

The point here is that putting one's own house in order generates increased returns; it also provides a convincing rebuttal to the charges of "country club management" often leveled at utilities, thereby improving the chances of being granted rate relief when requested. No slate of remedies for the utility industry can be complete without such a role for the individual companies themselves.

Where Do We Go?

What does all this mean? It means that alleviating the ills of the industry entails work for far more than just regulatory commissions. Without question the commissions have a full slate of tasks, but the government and the individual utilities also have a major role. Specifically, the roles can be described briefly as follows:

1. *Commissions.* The regulatory commissions simply must raise allowable returns so that utility returns are in line with the requirements of the

capital markets. Otherwise, the securities will sell at a discount to book value, and the current problems will be perpetuated. If euphemistic devices are needed to subvert the intense political pressures against raising allowable returns, they should be utilized. What is needed, however, is a competitive return on equity.

The regulatory commissions also must consider changing the nature of their involvement with the utilities they regulate. If regulation is to be nonmechanistic, commissions must develop the in-depth knowledge and skills to be discriminating questioners of utility managers, insightful readers of reports, knowledgeable buyers of expert service, and particularly evaluators of managerial performance. Then instead of mediocre returns for all utilities, the regulators could penalize undistinguished management with undistinguished returns on investment, and they could reward outstanding performance with outstanding returns. One could envision a system in which poorly managed utilities were granted a 10 percent return on equity, middle-ground utilities were granted 13 percent, and outstandingly managed utilities were granted 16 percent. Such a reward-oriented system could provide the utility industry with capitalistic incentives — no longer would the rewards of good management be turned over to the customers; rather, customers, shareholders, and management would all participate in the benefits. This idea is a clear departure from current practice. It would require effective regulators who could stand up to political pressure, who understand the economics of the business, who are willing to base decisions on solid analysis, and who will take effective action.

2. *Government.* The Federal government's role is two-fold. First, it must provide leadership in resolving the problems of the utility industry. Like it or not, many states look to the government to resolve many kinds of overall issues, including, for instance, the impact of peak-load pricing on load factors. This does not relieve others from responsibility for studying opportunities to resolve problems, but the government clearly has the lead. Second, the government has the job of sorting out national priorities and equities in the matter of subsidy-type programs. If rates are increased, is the $2 for $1 ratio appropriate? How much pressure should be put on the individual states to comply with such goals as normalized accounting or including construction work in progress in the rate base?

3. *Individual utilities.* There are three separate tasks the individual utilities must carry out to help themselves. First, they must become lean, hungry organizations — constantly on the lookout for profit improvement opportunitites. Second, they must sell more "good" product. As demand increases, they must work to reverse the deteriorating trend in load factor. Finally, they must learn how to attract and motivate the kind of management needed to run these companies. Times have changed, the job of management has changed, and the kind of manager needed has changed. Utilities must recognize that and move to meet that challenge.

The tasks outlined for the commissions, the goverment, and the individual utilities are not mutually exclusive. To the contrary, they require coordination and integration. Most important, each of the participants in the rescue process must demonstrate an understanding of the job the others have to do. A contrary example may illustrate the importance of understanding and coordinated action. The California Public Utilities Commission recently ruled to disallow all executive salaries in excess of $100,000 at Pacific Gas & Electric. While in the abstract that figure represents a handsome salary, the action shows little appreciation for the realities of an executive compensation structure or for the personnel development chore of a large utility. Should PG&E elect to limit top salaries to the allowed level, compensation throughout the organizational pyramid will be low. The likely result is that the better people will depart for higher paying jobs, or probably not join the company in the first place. That leaves less talented executives to inherit the key jobs — just at a time when the changed nature of the utility business is demanding better and better executives.

Finally, in carrying out their tasks all three participants must utilize thorough and imaginative analysis. The lists of remedies for the utility industry include many alternatives, each with its proponents and detractors. And the utility system is complex and interrelated — when one element is changed, often many others are affected, and the net result is not always obvious. Electrical peak-load pricing sounds so rational, but it will be no bargain if it generates severe needle peaks. In a similar fashion, liberalized depreciation policies or an investment tax credit may affect the actual level of capital expenditures in odd ways. Only with really good analysis are the proper strategies likely to be selected.

Discussion

Andrew F. Brimmer*

I would normally think that the fact that I'm now teaching at the Harvard Business School would be sufficient identification and would provide me with a cloak of legitimacy, but given the criticism I heard this morning about academics and bureaucrats who work inside offices, it occurred to me I should minimize the risk of being thought less able and suggest some additional basis for my standing here. I say this proudly and seriously because I do think we need to broaden the sources of information on which we are placing both analyses and judgments about the financing problems of public utilities. Now in addition to teaching at Harvard Business School I wear a couple of other hats.

One, I am director and economic advisor at a large chemical company, which uses a lot of energy. Not only is the energy provided by petroleum and natural gas, but in many places the company is the biggest customer of the local electric utility. Secondly, working with the company's economists I try to make some judgments about the long-run demand for and supply of oil energy in the United States, not simply that generated by electric utilities. I have some comments on that because the implication of the forecast made by the company's analysts casts a bit of doubt on the expected strength of demand for energy over the next decade at least. Currently I also sit on two investment committees. One committee meets once every two weeks and makes judgments about what to do with an enormous amount of money, and I assure you we are discounting heavily the prospects of public utilities, especially electric utilities, and little or no money is going in that direction. If anything, we are selling our utility bonds. The other committee is doing a similar kind of thing. I mention this because the capital market and the capital market's perception of the utility problem is a subject to which I want to address most of my remarks this morning. And finally I spend a lot of time with bankers, more now with commercial bankers than central bankers, and what they are telling me suggests an additional dimension of the financing problems faced by public utilities. Now if you think that's sufficient authority to speak on this subject — I will pause for a moment unless I am told to sit down — I'll proceed. Since I heard a laugh and not an indication to sit down, I'll proceed.

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The author of this paper sets out to achieve two objectives. The first aim is to provide an assessment of the experience of investor-owned electric utilities in New England in recent years. This goal requires as background an appraisal of the experience of electric utilities in the national economy. In particular, the author focuses on the industry's capital requirements, its growing dependence on external sources of funds, and the progressive weakening of its ability to attract investment funds — with special emphasis on its extremely limited ability to market common stock.

New England Experience

I have no basis for comment on the author's treatment of the New England experience. Although I have been concerned with — and have written a few papers on — the financing problems of public utilities, my own work has dealt with the issues in the national context. Consequently, I must take the author at her word as far as the experience of New England's public utilities is concerned. Yet, some of the variations in the New England picture sketched by the author (such as their relatively greater expenditures for the construction of nuclear power facilities) strike me as entirely consistent with trends in the Nation as a whole.

However, if I had been looking at New England explicitly, I would have put greater emphasis on the adverse impact which "consumerism" seems to have had on the public utility rate-making process in New England. In the spring of 1974, while I was still a member of the Federal Reserve Board, I conducted an informal survey (with the help of economists in the regional Federal Reserve Banks) of public utilities in order to get a feeling for "...the extent to which the regulators of public utilities at the Federal, state, and local levels appreciate the scope of the financing difficulties faced by public utilities and are responding to the need to assure a sounder financial base..." Of the 98 public utilities contacted in that survey, 20 were in New England. Forty-two of the total were electric utilities, and nine of these were in New England. There were also 25 combination gas and utility firms, and three of these were in New England. The responses to the survey suggested strongly that — at least into the spring of 1974 — public utility commissions had been extremely slow in responding to the requests for rate adjustments. The experience in New England was essentially the same as that for the Nation as a whole.[1]

In the last year, while public utility commissions seem to have become somewhat more responsive to the financial problems faced by the firms they regulate, organizations representing consumers seem also to have become stronger. With rare exceptions, their influence has been exerted in the direction of holding down the size of the rate increases actually approved. The latest example of this occurred here in Massachusetts a few

[1]See Andrew F. Brimmer, "Public Utility Pricing, Debt Financing, and Consumer Welfare," presented before the Wharton School Club of Washington, D.C., May 22, 1974.

days ago. According to newspaper reports, Boston Edison sought a $70 million rate increase. Instead, the State Department of Public Utilities approved an increase of only $26.7 million. Now on the record we know that commissions don't usually give applicants all they ask for but roughly 40 or 50 percent and in a few cases as high as 60 percent seems about in the ball park. So one could have thought some $35 to $40 million or thereabouts could have been expected in the terms of this application instead of the amount granted; the increase granted was only $26.7 million. More importantly, the Department exempted the first 384 kilowatt hours of residential use per month from the allowed increase. In so doing, it clearly was responding — at least partially — to the campaign of the Citizens Action Program on Energy (CAPE), a consumer action group. A central part of CAPE's program was the introduction of a so-called "lifeline supply" of electricity under which residential users would pay a flat rate for the first 300 kilowatt hours of residential use per month. While the Department rejected this concept, its decision to exempt the 384 kilowatt hours from the allowed rate increase was a step in CAPE's direction. Moreover, the Department allowed rate increases of $5.1 million for the New Bedford Gas and Edison Light Company and $1.1 million for Cambridge Electric Light Company, but neither of the latter two increases included an exemption for residential customers. So not only is the bow in the direction of CAPE explicit, it is discriminatory, and it clearly suggests that the big companies are the ones likely to have to bear this kind of additional burden.

Again, when we attempt to appraise the outlook for public utilities — in New England as well as the Nation as a whole — I think it is important that we give considerable weight to the probable impact of the consumer movement. My hunch is that the effects will be adverse to the utilities in the short run — and to consumers themselves in the long run.

National Experience

Let me now turn to the experience of electric utilities in the national context. Here I would like to make several points. The author of the paper uses the forecast of electricity demand and capital requirements developed by a committee of the Edison Electric Institute (EEI). This committee estimated that, from 1974 through 1990, the consumption of electric energy (measured in kilowatt hours) will expand at an annual rate of 5.3 to 5.8 percent. To meet this goal, construction expenditures would have to rise by 10 percent per year. On the basis of this forecast, the author agrees that the industry's capital requirements will indeed be enormous.

I do not wish to quarrel with this general conclusion. However, I think the demand for electricity — and capital requirements — may grow at a rate somewhat less than the range suggested by EEI. Of course, the EEI committee itself stressed that the growth in demand is likely to fall considerably short of the high rate recorded in recent years — e.g., 7.9

percent from 1960-73. The reduction can be traced to both the substantially higher price of energy and intensified conservation efforts.

I would like to stress an additional factor. This is the further decrease in the amount of energy required to produce a given volume of real output in the Nation as a whole. In 1947, it took 33.0 quadrillion Btus of primary energy to produce $309.9 billion of real gross national product (measured in 1958 dollars). (Here primary energy is defined as the aggregation of oil, natural gas, coal, hydro, and nuclear energy.) Thus, in 1947, the energy-GNP ratio was 106.5. In 1973, the consumption of primary energy amounted to 75.6 quadrillion Btus. Real GNP in that year amounted to $839.2 billion. Thus, the energy-GNP ratio was 90.1. A recent forecast (prepared by a large chemical company) of energy and output in the United States for the year 1985 put primary energy consumption in that year at 96.0 quadrillion Btus. Real GNP was projected at $1,170.0 billion — yielding an energy-GNP ratio of 82.1. The historical figures presented here represent an annual rate of increase of 3.1 percent in primary energy consumption during the 1947-73 period. The growth rate for real GNP was 3.9 percent, and the energy-GNP ratio declined by 0.6 percent per year. Over the forecast period 1973-85, primary energy consumption is projected to increase at an annual rate of 2.0 percent and real GNP is projected to rise at an annual rate of 2.8 percent. Thus, the energy-GNP ratio might decline by 0.8 percent per year.

The above estimates suggest to me that energy demand might grow less rapidly over the next decade because of continued increases in the efficiency of energy consumption in American industry. Furthermore, I would presonally doubt the likelihood of real GNP growing at an annual rate as high as 3.7 percent during the next 10 to 15 years. Instead, I would expect the higher price of energy (as well as actual shortages of natural gas) along with a long-run decline in labor productivity will most likely result in an annual rate of increase in real GNP over the next decade substantially below the 3.7 percent per year which underlies EEI's projection of energy consumption and electric utilities' capital requirements.

Electric Utilities in the Capital Market

The author of the paper also comments briefly on the problems posed by the increased reliance of electric utilities on external funds to meet their construction requirements. I agree with her general conclusions in this regard — especially with the emphasis on the constraints on equity financing arising from the fact that the market price of their common stocks has typically been so far below book value in recent years. Last June, I made a comprehensive analysis of the financing problems of public utilities.[2] The results of my own work amplify and extend the conclusions presented (briefly) by the author of the paper being discussed

[2]See "Financing Public Utility Investment Requirements," presented before the 43rd Annual Convention of the Edison Electric Institute, Denver, Colorado, June 3, 1975.

here. Consequently, I thought it might be helpful if I were to summarize the highlights of the paper I presented last summer:

- While electric utilities obtained over half of their total funds from internal sources a decade ago, less than one-third is generated internally today. Especially noteworthy is the fact that retained earnings provide only one-tenth of their requirements now compared with one-fifth ten years ago.
- The counterpart of this trend is increased reliance on the capital market. External funds have risen from about 40 percent to 70 percent of the total. The share of common stock climbed steadily from 6.6 percent in 1964 to 19 percent in 1973 — although the fraction dropped to 12 percent last year.
- The share of long-term debt rose from under one-third in 1964 to one-half in 1970; eased off to one-third in 1972, and climbed again to almost one-half of total funds raised last year.
- In the last few years, as they encountered difficulties selling long-term bonds, electric utilities have been forced to rely more heavily on temporary accommodations. Their short-term debt has risen from about 3.2 percent of total capitalization in 1971 to 5.7 percent in 1974.
- In the same vein, electric utilities have become noticeably more dependent on commercial banks. For example, electric utilities had borrowed 3.8 percent of the banks' commercial and industrial loans outstanding in April 1970. The fraction had climbed to 6.0 percent in April 1974, and it rose further to 7.2 percent in April of this year. Moreover, electric utilities have accounted for an even larger share of the banks' term loans (five to seven years in maturity) in recent years: 3.2 percent in 1970; 7.3 percent in 1974, and 8.3 percent in April of this year. Over this five-year period, about 18 percent of the net increase in commercial banks' term loans went to electric utilities.
- Reflecting increased reliance on external funds, public utilities have become a much more important force in the capital market. In 1964, they offered one-fifth of the new corporate bonds and stocks sold; by 1974 their share had climbed to one-third of the total. Their share of new stocks alone was even larger — in the neighborhood of two-fifths in 1972-73 and three-fifths in 1974-75. In contrast, while electric utilities were becoming a more powerful force in the capital market, gas and telephone were declining relatively.
- As is generally known, electric utilities remain much more dependent on public flotations of securities than do gas companies. The reasons are clear: regulatory posture in most states and better identification of most electric companies in the capital market. But the continued preference of electric utilities for very long bond maturities and the dislike of sinking fund arrangements also diminish the attractiveness of electric utility bonds to many life insurance companies who handle a sizable proportion of the direct placements.

- So, electric utilities are necessarily forced into the role of necessitous borrowers in the public capital market with few alternatives. Consequently, they have to give what the market demands — if they are to obtain funds. And what the market has demanded over the last year is a sizable interest premium. For example, in March 1974, new issues of high grade public utility bonds were yielding 165 basis points more than long-term U.S. Government bonds. After Consolidated Edison omitted its dividend in April last year, the interest rate differential jumped dramatically and rose steadily to reach 308 basis points last September. Although the yield spread has narrowed since, it was still 271 basis points in early May of this year. While industrial corporations also suffered to some extent in the general rush of investors into safer securities, the penalty was far smaller than that paid by electric utilities.
- As we look ahead, the demand for funds by electric utilities will remain strong. Despite the current slowdown in construction expenditures, the pace will pick up in 1976 and 1977. This will keep electric utilities heavily dependent on external funds and on the Nation's capital markets. In addition, utilities will have to refinance a heavy volume of low-coupon debt over the next several years. Thus, their interest costs will also rise appreciably.
- For these reasons, among others, electric utilities will need greater — and more speedy — rate relief than most regulatory commissions still seem inclined to grant them. Otherwise, consumers of electric energy — both business firms and households — are the ones who will suffer in the years ahead.