ANALYSIS OF SELECTED FINANCIAL ASPECTS OF THE ELECTRIC UTILITY INDUSTRY

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The NRRI is making this report available to those concerned with state utility regulatory issues since the subject matter presented here is believed to be of timely interest to regulatory agencies and to others concerned with utilities regulation.

PREFACE

This study presents three separate reports on several aspects of electric utility finances. They are not intended to tell an integrated story but rather to shed additional light on three major themes in the general area of utility finance - capital needs of the industry; regulation in a period of sustained inflation; and comparative returns and risk in the regulated and non-regulated sectors.

Recent increases in energy costs and the reported decline in the financial position of electric utilities have led some analysts to predict future capital shortages in this industry. Such claims are typically based on various analyses of future plant requirements by the electric industry, analyses of the total supply of investible funds, and predictions concerning the future competitive position of the electric industry in capital markets. Since capital shortages have the potential of disrupting the provision of electric services and regulators must pass on proposed investment decisions, understanding the basis for these predictions has important implications for regulation. Part I treats this subject.

At the same time, there exists substantial evidence that a portion of commission regulation has in the past decade become a matter of accounting for inflation. The regulatory response in the face of an inflationary environment has centered on a whole series of devices and practices designed to give financial relief to the power sector. Part II considers this issue in narrative fashion.

Company requests for rate increases and the efforts of consumer groups toward "holding the line" on utility prices have been combined to place deliberations of public utility commissions increasingly in the limelight. The close scrutiny resulting from such pressures has still further enhanced the need of regulatory bodies for accurate, useful financial data on utilities to enable them to carry out their regulatory mandates. A definite need exists for accurate and current information comparing the rates of return for the regulated and non-regulated sectors. Part III helps provide that information.

PART I - AN ANALYSIS OF SELECTED STUDIES OF CAPITAL NEEDS IN THE ELECTRIC UTILITY INDUSTRY*

*This report was prepared for The National Regulatory Research Institute at The Ohio State University. The views expressed are those of the author, Dr. Warren E. Farb, Consulting Economist, and do not necessarily reflect those of the Institute.

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EXECUTIVE SUMMARY

This report examines selected forecasts of the capital needs of the U.S. electric utilities industry during the next decade. It aims at providing a better understanding of these forecasts, and draws upon them to arrive at its own assessment of the electric utilities industry's probable capital needs between now and 1990.

Five recent studies, selected not only for their timeliness, but because they incorporate a range of methodologies and reflect a variety of institutional perspectives, are examined extensively: Electrical World's (EW) September 1978 annual forecast; an unpublished forecast by Data Resources, Inc. (DRI), based on their long-term trend macroeconomic forecast prepared during the winter of 1979; Bankers Trust Company's (BTC) U.S. Energy and Capital: A Forecast 1979-82 (1978); an estimate developed in a forthcoming book by Martin Baughman, Paul Joskow, and Dilip Kamat (BJK), Electric Power in the United States: Models and Policy Analysis; and the U.S. Department of Energy's 1978 projection of electric utility capital need which is included in the Energy Information Administration's Annual Report to Congress, Vol. II. A number of earlier studies are also reviewed briefly and compared with the EW, DRI, BTC, BJK, and DOE forecasts.

EW's forecast is essentially judgmental, while the others are based on econometric models of differing size and complexity; the most complex being DOE's Mid-range Energy Forecasting System. Of all the forecasts included in this analysis, DRI's is the most independent of its assumptions, since it is based on simultaneous macroeconomic and energy-sector models. Preliminary results are thus allowed to feed back on the overall conditions which produce them. In contrast, BJK's model is based on assumed external economic conditions, though it determines demand internally and uses cost factors and construction lags rather than assumptions to project the distribution of plant type. DOE's model is the most detailed, even though it currently relies on assumed macroeconomic conditions. In addition, DOE's model is probably the most responsive to factors affecting supply and demand for energy products of all types. Throughout the 1979 to 1990 period, because of lags between initial planning and completion, all of the forecasts are heavily influenced by announced plans, work in progress, and the assumed rates of postponement and cancellation.

Perhaps the most striking conclusion of this analysis is that the estimates of capital need are relatively independent of the estimation procedure. EW, DRI, BJK, and the DOE all produce remarkably similar results. The variations that do exist seem to be primarily a result of differences in assumptions. Among the most important of these assumptions are the rate of increase in electric sales and peak demand, the mix of plant type and assumed reserve margins.

The following table summarizes the aggregate forecast of capital needs for each of these studies:

SUMMARY OF FORECASTS OF
CAPITAL NEEDS OF
ELECTRIC UTILITIES

FORECAST	TIME PERIOD OF FORECAST	CAPITAL NEEDS (billions of 1979 $)
Baughman, et. al.	1979-1990	453
Bankers Trust Company	1979-1982	114
Department of Energy	1979-1985	229
Data Resources, Inc.	1979-1990	451
Electrical World	1979-1990	582

I. INTRODUCTION

This report examines selected forecasts of the capital needs of the U.S. electric utilities industry during the next decade. It aims at providing a better understanding of these forecasts, and draws upon them to arrive at its own assessment of the electric utilities industry's probable capital need between now and 1990.

The electric utilities sector is comprised of both investor- and publicly-owned companies. The latter account for about 25% of industry sales. They also tend to rely more heavily than investor-owned utilities on hydroelectric generation, and are therefore less burdened by the increasing cost of alternative energy sources. Also, because of their access to the public bond market, their financing costs are lower. Despite these differences in the financial characteristics of investor- and publicly-owned electric utilities, however, this report treats their capital needs in the aggregate. The primary concern here is not the cost of capital, but how much will be needed, and by implication (but not considered in this report) whether U.S. and foreign capital markets will be able to meet the demand.

If electric utilities could finance their needs entirely from internal sources, they would make few demands on national or international capital markets. In fact, however, in recent years they have relied increasingly on external financing.[1] In the 1970's, investor-owned utilities met 40-50 percent of their capital requirements externally. By 1972, the share of external financing had increased to 61 percent, and by 1974, to 71 percent.

The surge in external financing in 1974 seems to have been something of an aberration, resulting from the cumulative impact of inflation, high interest rates, and reductions in the rate of growth of demand for electricity. In 1976, however, after significant rate hikes, interest rate reductions, and curtailed plant construction had improved electric utilities' financial condition, the industry's external financing share was still 57 percent. In the current inflationary environment, this heavy reliance on outside capital is likely to continue, especially if electricity demand returns to pre-1974 growth rates. Inflation tends to reduce utilities' capacity to generate investment capital internally as costs increase more rapidly than rates.

Through the 1970's and into the early part of this decade, the capital requirements of the electric utilities increased dramatically relative to the rest of the economy. In 1970, capital outlays for investor-owned utilities amounted to 6.4 percent of all non-financial business outlays. By 1971, the figure had reached 10 percent, and Hass estimated (in a study published in 1974) that it would average about 10.5 percent through 1985.[2] A more recent study by Bankers Trust Company (1978) tends to sustain Hass' leveling projection. It also indicates a sharp drop in the electric portion of total energy industry capital demand (see Table 1). If there has been a leveling tendency in electricity's share of the business market, it is probably the result of increased energy prices, slowdowns in the growth of the peak demand, reduced sales growth, regulation, and uncertainties about nuclear power. However, the apparent drop in electricity's share of the energy industries' total capital demand reflects the increased capital needs of the oil and gas sector following the 1973 OPEC embargo rather than a scaling back of electric capital demand.

TABLE 1

ELECTRIC UTILITY AMOUNT AND SHARE
OF CREDIT AND CAPITAL MARKET,
1972 to 1977

	1972	1973	1974	1975	1976	1977
Capital and Credit Market (billions of dollars)						
Electric Utility External Financing	8.8	10.3	14.4	9.7	10.8	10.6
Energy Industry	11.3	13.3	20.3	17.5	21.5	22.5
Business Market	83	106	100	45	77	115
Total Market	178	202	189	206	269	338
Electric Utility Share of (percent)						
Energy Industry	77.9	77.4	70.9	55.4	50.2	47.0
Business Market	10.6	9.8	14.4	21.6	14.0	9.2
Total Market	4.9	5.1	7.6	4.7	4.0	3.1

Source: U.S. Energy and Capital: A Forecast 1978-82, Bankers Trust Company, 1978.

In absolute terms, the Bankers Trust findings suggest that electric capital demand overall has tended to increase steadily during the past several years.[3] Moreover, a second recent study by Electrical World indicates that absolute increases in electric power system capital expenditures may have been even larger than Bankers Trust believes.[4] Table 2 shows total U.S. electric power system capital expenditures as a share of total business expenditures for new plant and equipment.

Differences of opinion or method of counting the industry's past capital requirements complicate efforts to project such requirements through 1990. Surprisingly, however as we will see, there is substantial agreement on this issue among recent forecasts. The degree of consensus is especially interesting in view of the contingencies likely to affect electric utilities' capital investment over the next decade. First and foremost of these contingencies is the condition of the overall economy, and particularly the inflation rate. Inflation exerts a powerful influence on capital needs, not only because it tends to increase the utilities' dependency on external financing, but also because it affects economic growth and the growth in electricity demand.

In addition, environmental regulations continue to exert an uncertain influence on the amount of capital necessary to meet generation, transmission and distribution goals. Forecasts in the early 1970's, even if they assumed that anti-pollution restrictions would be imposed on the utilities, could only guess at the timing and cost of implementation. Recent studies are more informed about timing, but cost questions have yet to be answered with assurance.

TABLE 2

TOTAL ELECTRIC POWER SYSTEM CAPITAL EXPENDITURES
AS A SHARE OF TOTAL BUSINESS EXPENDITURES
FOR NEW PLANT AND EQUIPMENT, 1967 to 1977

(dollars in billions)

YEAR	ELECTRIC POWER CAPITAL EXPENDITURES	TOTAL BUSINESS NEW PLANT & EQUIP.	PERCENT ELECTRIC
1967	$ 7.9	$ 65.6	12.1%
1968	9.3	67.8	13.7
1969	10.7	75.6	14.2
1970	12.8	79.7	16.0
1971	15.1	81.2	18.6
1972	16.7	88.4	18.9
1973	18.7	99.7	18.8
1974	20.6	112.4	18.3
1975	20.2	112.8	17.9
1976	25.2	120.5	20.9
1977	27.7	135.8	20.4
1978	30.3	152.9	19.8

Source: Electrical World, September 15, 1978 and Business Conditions Digest, February 1979.

Energy prices and the effectiveness of the national energy conservation program are also powerful contingent influences on capital need. However, the mix of conventional and nuclear generating facilities may be even more important. As a rule, nuclear plants cost more than conventional ones, and take longer to bring "on line." For technical and political reasons, they are also most subject to postponements and cancellations in construction. While cancellations often reduce capital requirements, the effects of postponements are harder to anticipate. In the short term, decisions to extend construction schedules probably decrease capital requirements. However, continued delays may increase interest costs; single-shift construction may be less efficient; lower productivity may result from uncertain work schedules; and escalator clauses may apply over longer periods.

Finally, uncertainty about regional reserve requirements also increases the difficulty of forecasting electric utility capital needs. Assumptions about probable or "optimal" reserve margins are fundamental to all projections of peak generating capacity and therefore to estimates of capital needed for new generating facilities. Narrower reserve margins mean smaller capital requirements.

Several contingent factors--especially plant mix, energy prices, and inflation--have had a more profound influence on electric utility capital needs than could have been anticipated even a few years ago. In effect, the oil embargo and its aftermath, public ambivalence toward nuclear power, and nagging inflation constitute a water-shed between forecasts of the early 1970's and those of the past twelve or eighteen months. The most recent forecasts also reflect greater certainty about the timing of regulatory implementation; they are based on more up-to-date information on utility companies' construction plans; and they take account of the slower growth in electricity demand during the last half-decade.

For these reasons, recent forecasts of electric utility capital need are examined more extensively in the following pages than several well-known earlier studies, which are also reviewed. These recent studies have been selected not only because of their timeliness, but also because they incorporate a range of methodologies and reflect a variety of institutional perspectives. Of the five studies in this group, Electrical World's (EW) annual forecast is probably the most widely known and used in the industry. EW's projections, which extend through 1995, are not based on a formal econometric model. Hence, in a technical sense, they are more "subjective" than other estimates considered here. In contrast, the Data Resources, Inc. (DRI) forecast is based on the integration of simultaneous macroeconomic and energy sector models. DRI updates its projections several times each year. The forecast considered here is based on their long-term trend macroeconomic forecast prepared during the winter of 1979.[5] Bankers Trust Company's (BTC) U.S. Energy and Capital: A Forecast 1979-82 (1978) is included as a representative banking industry perspective on electric utility capital requirements. A fourth estimate, drawn from a forthcoming book by Martin Baughman, Paul Jaskow, and Dilip Kamat (BJK), is the only recent "academic" forecast examined.[6] A federal persepective is provided by the Department of Energy's annual projection of electric utility capital need.[7] DOE's findings are based on a sophisticated linear programming model--formerly called the Project Independence Evaluation System (PIES), now called the Mid-range Energy Forecasting System (MEFS)--which has been the controversial basis of much of the Department's analysis.

Three important, but dated, additional studies are also reviewed briefly below and compared with the EW, DRI, BTC, BJK and DOE forecasts: _Financing the Energy Industry_ (1974), by Jerome Hass, Edward Mitchell, and Bernell Stone; _Economic and Financial Impacts of Federal Air and Water Pollution Control on the Electric Utility Industry_ (1976), by Temple, Barker, and Sloane, Inc.; and the Federal Power Commission's National Power Survey, _The Financial Outlook for the Electric Power Industry_ (1974).

II. FORECASTS OF CAPITAL NEEDS

A. Electrical World, 29th Annual Electric Industry Forecast

The annual forecast prepared by the staff of _Electrical World_ is among the most widely used forecasts of the electric utility industry. The most recent _EW_ forecast was published September 15, 1978, and makes projections to 1995. It begins with a projection of overall economic growth and works toward the implications for the electric utility sector. For the 1980 to 1990 period, real economic growth is expected to average about 3.4 percent per year, with more rapid growth during the early 1980's, slowing to about 3% in the second half of the decade. This relatively modest projection assumes that accelerating wages, continued sluggish productivity growth, troubles with the dollar, and increasing energy prices will keep inflation rates high in the near term. In fact, recent developments suggest that the EW estimate of 6.3 percent inflation for the 1977 to 1981 period may prove conservative. For the 1982 to 1990 period, EW anticipates an average 5 percent inflation rate.[8]

EW's macroeconomic projections assume that current Administration efforts will have little short-term impact on inflation, and that persistent inflation combined with increasing real energy prices which drain purchasing power from other sectors will slow overall expansion. EW's general outlook also takes account of the implications for slower growth of an expected one percent increase in the working age population over the forecast period, down from two percent in 1967 to 1978. This reduction is important because new labor force entrants tend to be the principal purchasers of durable goods. In addition, EW notes that aging of the U.S. population at large implies an increase in the age groups that have already made major expenditures and are unlikely to reenter the market.

In translating economic growth into increased electric utility sales, EW breaks sales into four categories--residential, industrial, commercial, and other. Sales and peak demand are then estimated independently by region. Total sales are expected to grow at an average annual rate of 4.0 percent over the 1979 to 1990 period. In 1978, growth was less than 2.5 percent which EW believes artificially depressed the forecast base. EW assumes that the lost sales will be made up by a 4.4 percent increase in sales in 1979 despite their projection of slower economic growth in 1979 than in 1978.

Table 3 summarizes EW's electricity sales growth forecast. Growth in industrial use of electricity is projected to average 3.9 percent over the 1979 to 1990 period, a sharp downward shift from previous EW forecasts. This change is the result of slower-than-expected growth in the late 70's, a downward revision of expectations about industrial production in the second half of the 1980's, and an upward revision in estimates of the potential gains from conservation and improved energy management.

TABLE 3

ELECTRICAL WORLD FORECAST OF ANNUAL GROWTH
IN ELECTRIC UTILITY SALES

(billions of KWH)
1979 to 1990

YEAR	RESIDENTIAL	INDUSTRIAL	COMMERCIAL	OTHER	TOTAL
1979	4.4%	4.2%	5.0%	3.6%	4.3%
1980	4.4	3.6	3.0	3.4	3.8
1981	5.0	4.2	5.0	3.4	4.6
1982	4.7	3.8	5.5	3.4	4.5
1983	4.5	3.5	5.0	3.4	4.3
1984	4.4	3.8	4.5	3.4	4.2
1985	4.0	3.9	4.2	3.3	4.0
1986	3.6	3.9	4.0	3.4	3.8
1987	3.7	3.9	3.9	3.5	3.8
1988	3.4	4.0	3.9	3.4	3.7
1989	3.3	4.0	3.8	3.4	3.7
1990	3.3	4.0	3.8	3.4	3.7
1979-1990	4.0	3.9	4.2	3.4	4.0

Source: Electrical World, September 15, 1978

In determining capital needs, EW considers changes in peak demand and the gross peak margin to be more important than, and independent of, total sales increases. It reports that as a result of surprisingly slow peak demand growth in 1978, an unusually high reserve capacity margin, and continuing load factor deterioration, deferments and cancellations of planned projects are likely in the near term. However, EW is not prepared to view the low growth in 1978 peak as a harbinger of future developments. It forecasts a gradual decline in the gross peak margin from about 38 percent in 1978 to 18 percent in 1990, and anticipates that large capital expenditures for generation will continue to be required to meet the expected growth in peak demand. However, this estimate of peak demand growth and continued deterioration in load factor is based on past trends and judgement and may prove to be mistaken in an environment of rising real energy costs.

Table 4 summarizes EW estimates of capital expenditures for the 1979 to 1990 period. These estimates reflect the current slowdown in nuclear plant construction, although it is assumed that nuclear construction will pick up during the early 1980's. The estimates also reflect the costs of anti-pollution requirements. About one-third of distribution expenditures are expected to go for plant replacement, which makes them extremely sensitive to year-by-year decisions of management. Expenditures for transmission facilities are linked to generation additions and, therefore, reflect those patterns.

B. Data Resources Incorporated

Data Resources, Inc. (DRI) has estimated the capital needs of the electric utility sector as an integral part of their long-term macroeconomic forecast of the U.S. economy. DRI projects the capital needs

TABLE 4

ELECTRICAL WORLD FORECAST OF
ELECTRIC UTILITY CAPITAL NEEDS,
1979 to 1990

(billions of dollars)

	GENERATION		TRANSMISSION, DISTRIBUTION & MISCELLANEOUS		TOTAL	
YEAR	FUTURE $	1979 $	FUTURE $	1979 $	FUTURE $	1979 $
1979	23.1	23.1	9.7	9.7	32.8	32.8
1980	26.4	24.8	9.8	9.2	36.0	33.9
1981	28.4	25.1	11.1	9.8	39.4	34.9
1982	28.6	24.1	12.2	10.3	40.9	34.5
1983	29.9	24.0	12.8	10.3	42.7	34.3
1984	36.0	27.5	13.3	10.2	49.2	37.6
1985	48.6	35.4	14.3	10.3	62.9	45.8
1986	65.5	45.4	15.9	11.0	81.3	56.4
1987	78.0	51.5	18.6	12.3	96.6	63.8
1988	87.1	54.8	20.2	12.7	107.3	67.5
1989	94.1	56.4	21.7	13.0	115.7	69.3
1990	100.6	57.4	23.7	13.5	124.3	70.9
1979-1990	646.3	449.5	183.3	132.4	829.1	581.7

Source: Electrical World, September 15, 1978 of electric utilities based on their forecast of overall economic activity and then modifies these requirements by allowing the energy sector to "feed back" on their macroeconomic forecast. Prior to 1987, however, modeled forecasts of the utilities' needs are determined in conjunction with the announced construction plans of the companies.

The DRI energy forecast discussed here is based on DRI's long-term-trend macroeconomic forecast prepared during the winter of 1979. This forecast indicates that real GNP will grow by about 3.9 percent per year through 1985, with cyclical downturns in 1979 and 1982. For the 1986 to 1990 period, DRI expects real GNP growth to be about 3.1 percent per year. Throughout the 1979 to 1990 period, they foresee an inflation rate fluctuating between 5.4 percent and 7.6 percent--high by historical standards, but relatively stable.

From this macroeconomic base, DRI forecasts energy prices, which are combined with the industrial production index to determine industrial demand for electricity by region of the country. Per capita disposable income, population, and the stock of electrical household goods interact with energy prices to determine regional residential demand for electricity. Commercial electric demand is determined by energy prices and commercial employment by region. Throughout this process the DRI model permits substitution among fuels as various prices change in response to demand. Energy prices fed back into the macroeconomic model allow simultaneous determination of energy prices and relevant economic variables such as industrial production. In contrast, EW seems to rely exclusively on announced plans and judgement in determining demand and the mix of new generating plants.

Once regional demands for electricity are determined by the DRI model, the totals are adjusted to include interdepartmental, own, and railroad use.

Then they are summed. The result is converted to a generation-to-demand ratio for each region to reflect existing patterns of transmission. The reserve margin for each region is then derived based on an estimate of peak demand developed from the historic peak load factor in each region.

By relating the capital need to peak demand and assuming a constant load factor, the DRI system implicitly assumes that the mix of base, intermediate, and peak generating plant will remain constant. The calculations of the cost of additional plants are based on this ratio and per kilowatt hour construction costs. In contrast, EW's method of estimating total sales and peak demand growth separately allows their forecast to reflect a changing mix in the type of generating plants built. However, EW's forecast is subject to second guessing regarding the relative growth rates in base, intermediate, and peak demand. The Department of Energy methodology, discussed in Section E employs load duration curves for each region to escape the dilemma of assuming the current relationships (DRI), or the continuation of trends (EW) and thus allows the greatest flexibility in forecasting plant requirements. However, the DOE's load duration curves are greatly influenced by current operations; so in practice their estimates are probably not significantly different from DRI's.

DRI's projections of the electric utilities' capital needs are determined for each region by allowing the electrical system to move toward a subjectively pre-determined regional "target" reserve margin. The "target" reserve margin is based on historical relationships and existing interconnections between companies and regions.

DRI's capital need estimates are by the year the project enters the rate base rather than by actual annual expenditures. Prior to 1987, therefore, work planned and in progress modifies the model's attempt to move the system toward the target reserve margin since it would be impossible to plan, build, and open a plant in 1987 that is not already somewhere in the planning-construction cycle. Also, projects already fully committed cannot be cancelled even if they will not be needed. The costs of conventional generation facilities are determined by summing the planned increases in rate base across all companies. As in the EW forecast, each electric utility company is considered separately. For nuclear plants, DRI exercises some judgement in extending the reported timetables because of the poor track record of utilities in completing these projects according to plan.

While the DRI methodology can be criticized as being overly tied to past relationships, it does provide a benchmark for gauging alternative assumptions. If it is assumed that the load factor continues its downward trend, the DRI estimates will be low. Alternatively, if the load factor improves, the DRI estimate will be high. Regardless of the actual result, the basis for comparison is a known.

It should be noted that the DRI model assumes a continuation of existing regional generation-to-demand ratios. These ratios may also change over time, affecting the capital needs estimates. It is also likely that revised versions of the DRI model will attempt to estimate the growth in peak demand directly rather than assume a fixed relationship to sales growth. But, this "improvement" may be of limited value since it will necessarily be tied to weather, the rate of technological change, and conservation.

Finally, it is important to remember that the DRI estimates of capital needs are not year-by-year expenditures. They are capital increases coming on line in a given year. In most jurisdictions, this means that the total cost of a given plant is counted in the year it enters the rate base. Consequently, the DRI capital needs forecast is not comparable to the others which are reported here on a year-by-year basis. An approximate comparison, however, can be made by summing the expenditures over several years. Table 5 shows the capital expenditure estimates of DRI and selected alternative forecasts for 1979 to 1985, 1986 to 1990, and for the entire 1979 to 1990 period.

As is expected from the relatively high, but perhaps realistic, inflation rate incorporated in the DRI forecast, the current dollar estimates appear higher, in comparison with the other projections, than the estimates based on constant dollars. Nevertheless, the DRI forecast of capital requirements tends to be on the low side, primarily because of a relatively low estimate (3.2 percent) of annual growth in electric sales for the forecast period. Moreover, because of the way the DRI model is constructed, the introduction of a business downturn would reduce the demand for electricity and consequently the optimal capital requirements. The reduction in the optimal capital needs would reduce the actual capital needs in the 1986 to 1990 period and would probably result in further delays in the completions and activation of nuclear plants.

C. Bankers Trust Company

In 1978, Bankers Trust Company (BTC) published a "best guess" as to the capital needs of the electric utility industry extending through 1982. This estimate is a part of a planned biennial review of the U.S. demand and supply of energy and the consequent capital needs for the energy industry as a whole.[9]

TABLE 5

DRI AND SELECTED ALTERNATIVE FORECASTS
OF ELECTRIC UTILITY CAPITAL NEEDS,
1979 to 1990

(billions of dollars)

	FUTURE $			1979 $		
	1979-1985	1986-1990	1979-1990	1979-1985	1986-1990	1979-1990
DATA RESOURCES INCORPORATED						
Generation	207.5	321.4	528.9	164.3	186.9	351.1
Transmission, Distribution, & Misc.	73.4	68.1	141.5	60.3	39.8	100.1
TOTAL	280.9	389.5	670.4	224.4	226.5	450.9
ELECTRICAL WORLD						
Generation	221.0	425.3	646.3	184.0	265.5	449.5
Transmission, Distribution, & Misc.	83.2	100.1	183.3	69.9	62.5	132.4
TOTAL	304.2	525.4	829.6	253.8	327.9	581.7
BOUGHMAN, JOSKOW & KAMAT						
Generation	135.8	216.2	352.0	113.2	132.9	246.1
Transmission, Distribution, & Misc.	125.5	166.3	291.8	104.8	102.0	206.8
TOTAL	261.3	382.5	643.8	218.0	234.9	452.9

Source: Table 4, Table 9 and Data Resources Incorporated

Unlike DRI, EW and other forecasters, BTC assumes certain macroeconomic conditions rather than determining them independently; though it seems likely that their assumptions are influenced by the available economic forecasts including DRI's and EW's. BTC assumes that economic growth, as measured by the rate of increase in real GNP, will range between 3.2 and 4.3 percent and average 3.8 percent between 1978 and 1982.

The relatively narrow range of assumed annual GNP increases seems to indicate that BTC expects the economy to be free of any major cycles over the forecast period. BTC also seems to assume that the domestic inflation rate and the rate of increase in world crude oil prices will be relatively constant at about 6 percent. They expect domestic energy prices to rise somewhat faster, however, because of increases toward world price levels of domestic oil and gas. Domestic crude oil is assumed to equal world prices by 1982, and natural gas is assumed to approach the world price of crude oil by 1982 (on the basis of equivalent BTU content). BTC assumes more rapid price advances for capital goods in the energy sector (6.3 percent) than for the economy as a whole. The 5-percent differential is attributed to high rates of investment in some of the energy industries that force up the cost of materials and skilled labor.

Finally, BTC also assumes that government tax policy will not play a significant role in determining energy use; that there will be adequate available supplies of oil and natural gas; that any shortage of domestic capital will be made up from foreign sources, since rates of return will be high enough to attract the needed capital; and that there will be no significant alteration in government statutes or regulations relating to environmental protection.

On the basis of these assumptions, BTC estimates the amount and type of energy needed by consuming sectors. Table 6 summarizes their estimates of electricity sales growth by sector. In the household and commercial areas, they expect that electricity use will increase at a 4.6 percent average annual rate, although they see total energy use in this sector increasing at less than half the historic rate, largely because of consumer efficiency in response to higher prices. BTC expects efficiency increases to be concentrated in the household sector, but they also think that commercial electricity use will grow at less than its recent historic rate.

TABLE 6

BTC ESTIMATES OF AVERAGE ANNUAL GROWTH
OF ELECTRICITY DEMAND BY CONSUMING SECTORS, 1979 to 1982
(percent)

Sector	1979	1980	1981	1982	1979-82
Household & Commercial	4.3	4.2	4.0	5.8	4.6
Industrial	3.1	6.1	5.7	5.4	5.7
Total	3.7	5.2	4.9	5.6	5.2

Source: Bankers Trust Company, 1978

Within the household sector alone, which is not reported separately, BTC expects the growth in electric consumption will be influenced by the makeup of the housing stock. Even though they forecast an average annual rate of more than 2 million new units, they think these houses will be more energy efficient than older units. They see space heating demands for all types of energy moderating as uninsulated older units are replaced with more energy efficient ones. Also, BTC estimates that 3 to 4 million additional existing housing units will be insulated each year, further reducing the growth in energy demand of the housing sector.

BTC estimates that commercial use of all energy will grow at 6.5 percent per year. While this is more than the average rate of increase for the economy as a whole, it is well below historic growth rates for the commercial sector which have ranged up to 9 percent per year. BTC attributes this still relatively high (6.5 percent) projection to continuing increases in services as a share of GNP. Since the conservation potential of this sector is comparable to the household sector, some reduction from the historic growth rate is to be expected. Judging from the estimates shown in Table 6, however, it appears that BTC expects most of the savings to be reflected in reduced growth in demand for non-electric energy sources instead of electricity itself.

BTC's assumption about the sensitivity of energy demand to price is particularly evident in the industrial sector. They see total energy demand by industry increasing by only 2.5 percent per year. Electricity consumption, however, is forecast to increase 5.7 percent per year--a rate comparable to pre-embargo electric demand growth. Even though electricity prices are expected to increase, BTC does not believe that the industrial sector will be able to substitute fuels or significantly improve the efficiency of electricity use. The DRI model, in contrast, specifically allows for fuel substitution in response to fuel price changes. The major link between DRI's macroeconomic and energy models is the impact of fuel price increases on demand for each type of fuel and the simultaneous impact of changes in energy prices on industrial production. In view of the different time horizons of the two forecasts, this contrast is probably less important than it appears. While it is reasonable to assume that industries will adjust to the increasing real price of energy over time, the process is likely to be an extended one.

Even with the relatively rapid rate of increase in commercial use of electricity, BTC forecasts only a 5.2 percent annual growth in the total demand between 1978 and 1982. This is considerably below the 1970 to 1973 rate of 6.6 percent, but well above the rates assumed by EW and DRI.

BTC does not consider the rate of increase of peak demand growth separately from sales growth. Consequently, even though the BTC analysts foresee some efficiency improvement as a result of price increases, they do not expect this to affect load factors. The mix of base and peak load generating capacity is, therefore, implicitly assumed to be unchanged over the forecast period.

In converting the estimates of increased electric consumption to required additional generation capacity and capital needs, BTC concentrates not only on aggregate demand, but on the electric industry as a primary consumer of fuel. As Table 7 shows, they expect electric utilities' total energy demand to increase at a 4.6 percent average annual rate between 1978 and 1982, with largest increases for coal and nuclear generation.

BTC projects that the electric utility sector will increase its dependence on coal-fired generation, and that by 1982, it will produce

TABLE 7

BTC FORECAST OF GROWTH OF ENERGY FUEL SOURCE
DEMAND FOR ELECTRIC GENERATION
1978 to 1982

(percent)

Demand for:	1979	1980	1981	1982	1978-1982
Coal	7.0	5.7	6.2	4.4	5.8
Petroleum	4.7	2.2	2.2	0.0	2.2
Natural Gas	-14.8	-13.0	-15.0	-11.8	-9.6
Nuclear Power	14.8	19.4	16.2	23.3	18.4
Hydro Power	0.0	0.0	0.0	0.0	0.0
Total	4.1	6.0	3.4	5.1	4.6

Source: Bankers Trust Company, 1978

half of its total power output with coal. More importantly, in terms of capital demand, BTC contends that, despite cancellations and delays in construction, nuclear facilities will meet 18 percent of the utilities' generation needs by 1982. In 1976, nuclear plants accounted for only about 9 percent of the electric utility industries' energy requirement.

BTC's estimates of the capital needs of the electric utility sector for 1979 to 1982 are summarized in Table 8. These forecasts are based on announced plans, but they also try to allow for slippage in construction schedules, optimism, inconsistency with the industry needs and institutional and other factors. Although Table 8 is constructed to be comparable with the other similar tables in this report, the BTC study provides details which are not presented there. In particular, it includes two categories of capital expenditure not considered separately by the others: flue gas desulfurization; and working capital. In Table 8, the flue gas desulfurization is added to the generation category. The working capital estimates, important to BTC because of their interest in total financial requirements of the industry, are short term and not a direct indication of the industry's need for investment funds. Thus, they are excluded. BTC also breaks down the capital needs estimate into internal and external financing requirements. The industry's external financing needs are projected to be lower during the 1979 to 1982 period than during the 1970's. BTC estimates that only about 4 percent of total capital and credit, and 10 to 11 percent of the share of the capital and credit going to business, will be absorbed by the electric utility industry over the forecast period. In the early 1970's, electric utilities accounted for 5 to 7 percent of the total capital and credit market, and for the 1972 to 1977 period, on average, about 13 percent of the business (see Table 2).

TABLE 8

BANKERS TRUST COMPANY FORECAST
OF ELECTRIC UTILITY CAPITAL NEEDS
1979 to 1982

(billions of dollars)

	GENERATION		TRANSMISSION, DISTRIBUTION & MISCELLANEOUS		TOTAL	
	FUTURE $	1979 $	FUTURE $	1979 $	FUTURE $	1979 $
1979	19.6	19.6	9.8	9.8	27.4	27.3
1980	19.5	18.3	10.5	9.9	30.0	28.2
1981	21.4	18.9	11.1	9.8	32.5	28.8
1982	23.3	19.4	11.7	9.7	35.0	29.1
1979-1982	81.8	74.2	43.1	39.2	124.9	113.5

Source: Bankers Trust Company, 1978

BTC's forecast of $74 billion in real capital needs for generation between 1979 and 1982 is considerably lower than EW's or DRIs. The discrepancy may stem partly from the proximity of BTC's time horizon and from the presumed impact of energy conservation. More importantly, however, BTC analysts may have been persuaded to stretch out estimated construction schedules because of declining growth in electricity demand in the late 1970's, and because they foresee high reserve margins and increasing reliance on nuclear generation during the forecast period. Historically, nuclear plants have taken longer to bring "on line," and have been more susceptible to construction delays and cancellations than conventional facilities.

Although BTC's projected capital needs for generation is lower than other forecasts, they expect generation expenditures to increase more rapidly than expenditures for transmission and distribution. This is partly because of the high cost of nuclear plant construction, but also because of anticipated construction delays which tend to increase overall production estimates. In contrast, EW assumes continuation of past average trends in construction expenditures for generation. Surprisingly, however, their estimates of transmission and distribution outlays are about the same as those forecast by BTC.

D. Baughman, Joskow and Kamat

In a forthcoming book on the electric utilities industry, Martin Baughman, Paul Joskow and Dilip Kamat (BJK) have three main goals: to forecast the capital needs of the industry over the next twenty-five years and the primary sources of that capital; to demonstrate that a capital shortage for a regulated industry is conceivable; and to examine the effects on the electric utility industry of several regulatory and tax policy changes.[10] Their capital need forecast covers 1976 to 2000, but only the results for the 1979 to 1990 period are considered here.

BJK have constructed their own model of the U.S. electrical power industry. In developing their base case forecast, they incorporate what they believe to be the best estimates of current trends and expectations for the various macroeconomic, energy supply, capital equipment cost, and regulatory parameters. They make optimistic assumptions about financial conditions to bias the results slightly away from a capital shortage situation. In this way the impact of changes in the regulatory environment on capital availability can be more fully appreciated.[11] However, it should be recognized that BJK's estimates of electric utility capital need are somewhat higher than they would have been if financial conditions were assumed to be less favorable to the industry. In fact, BJK's estimates are still relatively conservative, even for projections made in 1976. Between 1975 and 1979, most electric utility analysts have been revising their forecasts of capital needs downward as demand has increased more slowly than expected.

The BJK model does not attempt to forecast basic economic variables for the forecast period. Instead, it assumes that the economy will grow at an average annual rate of 3.8 percent, somewhat higher than the DRI forecast. The inflation rate is assumed to be 5.5 percent per year, which is probably low given today's economy. Other exogenous variables include population, income and value added in manufacturing. This last variable is a measure of industrial production and plays an important role in determining industrial demand for electric power.

In conjunction with assumed primary energy prices, these economic variables determine the price of electric power by region. Once energy prices are determined, the model forecasts total electric demand, which is converted to a peak demand forecast through the use of historical load factors for each region of the country. Unlike the DRI forecast which assumes historic load factors, however, BJK expect load factors to decline slightly throughout the 1980's and then hold constant through the rest of the forecast period by BJK. Their forecasts of peak demand are, therefore, dependent on two key exogenous assumptions--the growth rate of the economy and the load factor. Slower economic growth or cyclical rather than steady growth would result in lower estimates of peak demand. Also, if load factors should improve, lower estimates of peak demand would result. From the peak demand estimates, the model determines the necessary electric generating capacity.

Additions to capacity depend on the lead time required, the cost of alternative types of generation plants, and the reserve margin in each region. BJK assumes that nuclear plants require 10 years, fossil fuel plants 4 years, and gas turbine plants 2.5 years to come "on line." The target reserve margin is set at 20 percent in all regions; but through 1985 the additions to capacity are modified to take into consideration plans already announced. As is true in the other forecasts considered here, the announced nuclear plans are stretched out to allow for construction and regulatory delays.

Table 9 summarizes BJK's base case forecast of the electric power industry's capital expenditures through 1990. BJK differ considerably from other estimates with regard to the composition of the expenditures

TABLE 9

BAUGHMAN, JOSKOW AND KAMAT FORECAST
OF CAPITAL NEEDS OF THE ELECTRIC UTILITY SECTOR
1979 to 1990

(billions of dollars)

	GENERATION		TRANSMISSION, DISTRIBUTION, & MISCELLANEOUS		TOTAL	
	FUTURE $	1979 $	FUTURE $	1979 $	FUTURE $	1979 $
1979	10.5	10.5	12.5	12.5	23.0	23.0
1980	14.9	14.1	13.3	12.6	28.2	26.7
1981	19.7	17.7	16.4	14.7	36.1	32.4
1982	22.4	19.1	18.3	15.6	40.7	34.7
1983	19.2	15.5	20.2	16.3	39.4	31.8
1984	19.9	15.2	20.9	16.0	40.8	31.2
1985	29.2	21.2	23.9	17.3	53.1	38.5
1986	38.7	26.6	27.8	19.1	66.5	45.7
1987	42.6	27.7	31.0	20.2	73.6	47.9
1988	41.5	25.6	32.9	20.3	74.4	45.9
1989	43.4	25.4	35.1	20.5	78.5	45.9
1990	50.0	27.7	39.5	21.9	89.5	49.6
1979-1990	352.0	246.3	291.8	207.0	643.8	453.2

Source: Baughman, Joskow and Kamat, forthcoming between transmission and generation, and the distribution of these expenditures over time. In the EW and DRI forecasts, nearly 80 percent of all capital expenditures between 1979 and 1990 are for generation. In contrast, BJK expect these expenditures to be about evenly split between generation and transmission, distribution and miscellaneous. Although the disparity is not completely accounted for, BJK point out that they include the costs of any transmission required to tie new generating plant into the transmission grid as a transmission expenditure, while EW and the others follow the more usual convention of counting these as generation expenditures.

Other disparities in the proportion of expenditures for generation may arise from differing assumptions about generation-to-demand ratios for each region. EW and DRI follow historical patterns to determine regional load factors. In the DRI model, these load factors are used to develop estimates of peak demand which are then compared with generation capacity to determine the region's reserve margin. Regions traditionally selling large amounts of power to neighboring areas are, therefore, assigned higher target reserve margins than regions that have a history of purchasing power to meet peaks.

BJK's targeting of all regions to a 20-percent reserve margin after 1985, makes a different pattern of expenditures inevitable. While it is impossible to determine which of the assumptions regarding reserve margins is better, it is clear that a lower target margin reduces capital needs for generation capacity, but possibly increases the capital needs for transmission and distribution facilities. The DRI projections for new plants, therefore, may be somewhat lower because they allow for some reserve margins to go as low as 15 percent. However, this may not be reflected in the summary tables because of DRI's practice of including costs of tying a plant into the transmission grid as generation expenditures. The relatively high EW forecast also allows reserve margins to fall below 20 percent, on average. The EW forecast, however, is also heavily influenced by its estimates of sales and peak growth in determining capital needs.

E. United States Department of Energy

The Department of Energy's (DOE) forecast of the capital needs of the electric utility industry is included as a part of their annual projections of national supply and demand for energy. Three separate estimates are reported based on alternative assumptions put through the Mid-Range Energy Forecasting System (MEFS), formerly known as the Project Independence Evaluation System (PIES).

MEFS is a comprehensive energy model designed to forecast energy equilibrium conditions in the U.S. economy.[12] Of the models discussed in the report, it is by far the most extensive and complex. Moreover, the electric utility sub-model of MEFS is the most detailed and complex of the various pieces that make up the complete system. MEFS produces "snapshots" of the energy economy on an average day at specified planning horizons. For the 1978 Annual Report, these snapshots were for January 1, 1985 and 1990. The capital needs estimates, however, were only calculated for the 1985 equilibrium. It is expected that the 1979 report will show capital need forecasts for each year through 1990.

MEFS can be thought of as having three basic pieces: a demand model, a supply model, and an equilibrating mechanism that brings the supply and demand sides together. The equilibrating mechanism, which is the heart of the system, is a static linear programming model which produces optimum supply and equilibrium pieces given forecast demand levels, capacity and cost considerations, and policy decisions such as price regulations that can influence market behavior. For the electric utility sector, MEFS estimates future demand for electricity, capacity additions, capital coefficients, activity levels, and capital requirements in dollars.

The MEFS equilibrating mechanism, or integrating model, determines a partial equilibrium of supply and demand for different fuel types for each of ten DOE regions. The model forecasts energy consumption levels in each of the regions and shows how consumption is distributed among ten fuel products, including electricity. It also identifies the geographic source of these fuels, how they will be transported, and how they will be converted for final consumption. This is done through a series of 300 fuel demand functions that are estimated econometrically, and numerous fuel supply schedules that are estimated by engineering-economic models which permit profit maximizing private behavior. The integrating model then finds the least-cost way to satisfy the demands, subject to the costs of transporting and converting raw energy into the energy products demanded, and subject to the other constraints including the linear program. MEFS supplies information about the entire energy sector. In this report, however, only those parts of the model that relate to the capital needs of the electric utility industry are discussed.

To begin the forecasting process, MEFS requires that the equilibrium values of GNP, population, and income for the target years be assumed or supplied from some other source. For the 1977 Annual Report, ten alternative combinations were developed, but only three were used to estimate capital needs. One of these, the reference case, is based on mid-range supply and reserve, and moderate economic growth assumptions. The "high" case assumes high resource availability, low capital equipment cost inflation and relatively rapid economic growth. The third or "low" case assumes that resources will be scarce, capital cost inflation high, and economic growth slow. All three alternatives assume that the world real price of crude oil will be constant at $15.32 (although some of the other alternatives allow the price to increase 5 percent per year).

The demand side of MEFS is relatively simple in comparison with the supply side. Demand functions are estimated for 30 separate products in each of the ten regions. These functions are governed by the general level of economic activity, the nature and extent of conservation programs, and numerous other assumptions.[13] Unlike the DRI model, neither these econometrically-derived demand functions, nor any of the subsequent assumptions or estimates feed back on a macroeconomic model.

Future development of MEFS will include much more detailed demand sectors, particularly for households, that will interact with the rest of the model. Until these new modules are completed, however, the Department of Energy will probably continue to use widely available macroeconomic forecasts (e.g. DRI's) that reflect a consensus view of aggregate demand. Since the models which generate these forecasts incorporate energy sectors, albeit much more aggregated ones than MEFS, it is possible that unknown biases are being introduced into the MEFS forecast.

Table 10 summarizes the three key macroeconomic assumptions for the MEF's "high," "medium," and "low" forecasts. MEFS's reference or "medium" case macroeconomic assumptions are those of the DRI "TRENDLONG,"

TABLE 10

MACROECONOMIC ASSUMPTIONS OF THE DOE FORECASTS
(Average Annual Rate of Growth)

Year	High	Medium	Low
Real Gross National Product			
1974-1980	5.5	4.7	4.7
1980-1995	3.4	3.7	3.0
1984-1990	2.9	3.1	2.4
Real Value Added in Manufacturing			
1975-1980	7.9	6.5	6.4
1980-1985	4.3	5.1	4.5
1985-1990	3.8	4.3	3.1
Real Personal Disposable Income			
1975-1980	4.7	3.8	3.9
1980-1985	3.2	3.8	3.1
1985-1990	3.1	3.5	2.9

Source: Energy Information Administration, Annual Report to the Congress, Vol. II Appendix, (U.S. Department of Energy, Washington, D.C. September 1978) released in August 1977. According to this forecast, the economy will grow at an average annual rate of about 3.7 percent between 1980 and 1985, and then slow to a 3.1 percent rate during the 1985 to 1990 period. Inflation is expected to average about 5.5 percent through 1983, with the annual rate declining to 4.1 percent by 1990. Energy prices at the wholesale level are expected to increase at an annual average rate of about 7.5 percent, which is roughly consistent with the MEFS assumption of a constant real-world oil price.

The "high" forecast is based on the DRI "CEASPIRIT" of early 1977. The economic strength projected in this forecast assumes a somewhat slower average rate of inflation through 1983 than the "medium" case (about 5.2 percent), and a significantly slower rate of increase in wholesale energy prices (5 percent). This later assumption is inconsistent with the MEFS assumption of constant world oil prices, and therefore causes MEFS to estimate supplies of the various energy products at higher prices than DRI used to determine aggregate demand. Any bias this may introduce into the estimates, however, is at the least partially offset by the assumed larger domestic oil supply.

MEF's "low" estimates are based on the DRI "CYCLELONG" alternative of August 1977. In this simulation, inflation is forecast at a 7-percent annual rate through 1983, increasing to 8 percent during the 1984 to 1990 period. Over the full forecast period of 1978 to 1990, the "low" alternative predicts an average annual rise of more than 12 percent in wholesale energy prices. However, any excess supply of energy resulting from higher prices is offset by assumed lower domestic supplies.

The supply side of MEFS is comprised of a series of independent models which represent the flow of fuels from production through conversion to final demand. The electric utilities submodel estimates the new generating capacity required to meet the demand for electricity. Subject to price and supply constraints, the model chooses the types and mix of capacity required to meet load demands that is consistent with the overall optimization throughout MEFS.

The results of the MEFS model, therefore, reflect the generating capacity that is "on line," as do the DRI estimates. In contrast to DRI, however, since a primary interest of the DOE is to indicate the impact of energy supply and demand on the capital market, they have adjusted the MEFS results to show capital expenditures made during the forecast period. These initial results from MEFS are reduced by an estimate of capital costs made prior to 1978, and to the extent possible, based on announced plans adjusted for delays and postponements. Through 1984, the capital cost of work in progress on plants not yet in service but under construction is added.

Even after the adjustments for work in progress are made, however, the DOE estimates are still not easily compared with the others included in this report. Because the MEFS model is designed to forecast an equilibrium for a given date, its capital need forecast is not annual. In the case of the Annual Report for 1977, for example, the estimate of capital needs covers the entire period from January 1, 1978 to January 1, 1985.

In determining capital needs, the electric utilities submodel converts demand into base, intermediate, and peak load by using regional load duration curves. Although these curves are determined exogenously, they follow existing load patterns.[14] The model then determines the amount and type of generating plant needed to meet the three modes of demand within each region. Regions are constrained to build enough capacity to meet their own demand within certain bounds. The upper bounds for 1985 consist of the announced plans of utilities. No region is allowed to build more capacity in 1985 than had entered the planning stage by 1978. By 1990, except for nuclear plant construction, which has a very long planning and building cycle, upper bounds are generated by the model. The lower bounds require that fully committed plans be completed, but allow postponement and cancellation of other projects. The determination of construction needs is also based on the assumption that each region will move toward a 20-percent reserve margin.

MEFS assumes that a broad spectrum of generation equipment will be used, including nuclear and coal, residual oil, simple-cycle turbines, combined-cycle turbines, and hydroelectric. Assumptions about capital and operating costs are established for each equipment type and each set of load factor characteristics. The capital costs vary by region, plant type and target year of operation. In addition, the required expenditure per unit of construction includes the cost of a unit of transmission and distribution equipment. In the case of coal facilities, separate cost assumptions are made by type of coal for plants with and without scrubbers.[15]

Table 11 shows the DOE estimates of electric utility capital needs for the period between January 1, 1978 and January 1, 1985. These estimates are based on the MEFS forecast of capacity and equipment requirements for 1985 and 1990. It is assumed that the plant openings are spread evenly over the period 1978 to 1985. Capital expenditures are distributed equally over a ten-year period for nuclear plants and over a seven-year period for fossil fuel plants. MEFS's capital need estimates are then adjusted to exclude the capital costs incurred prior to January 1978 for plants opening during the forecast period. Conversely, capital costs incurred prior to January 1, 1985 of plants opening between 1985 and 1990, are included in the estimate. Since the 1990 cutoff date is too early to capture all of the capital costs incurred prior to 1985, it is assumed that an equal number of plants will open between 1990 and 1995 as will open between 1985 and 1990. To facilitate comparison, the DOE forecast is juxtaposed in Table 11 with the portions of the EW and BJK projections falling within the MEFS forecast period. It should be noted, however, that since the EW and BJK forecasts do not include 1978, they are biased slightly upward.

F. Other Estimates

The previous sections have presented several estimates developed over the past 3 years of the future capital needs of the United States electric power industry. While these estimates vary, all reflect the impact of increased energy prices following the 1973 OPEC embargo; in particular, reductions in sales and peak demand growth, undesirably high reserve margins, and reduced estimates of physical plant requirements. Because of the higher than anticipated inflation rate since 1973, however, recent forecasts of capital need may not vary much from earlier estimates.

The latest forecasts also account more fully for capital expenditures needed to meet anti-pollution requirements. Earlier forecasts, even if they assumed that clean air and water restrictions would be implemented, could only guess at the timing and cost. It can be argued that the current forecasts are still only guessing at the costs of anti-pollution equipment. Nonetheless, more cost information is available, and the timing of the standards appears to be settled.

Despite these differences, comparison of the latest forecasts and those of the recent past based on similar methodologies reveals a similarity in capital needs estimates that seems puzzling. The early studies' higher estimates of electric utility growth ought to yield higher estimates of capital need if the cost of capital remained constant. Costs, however, increased rapidly between the early 1970's and the common base year of this report, 1979. Moreover, capital costs to electric utilities were increasing more rapidly than the general inflation rate. Unfortunately, data limitations have made it necessary for the purposes of this report to adjust the results of these studies with general rather than differential inflation rates. Consequently, the estimates summarized in Table 12 understate the capital needs that would have been projected had it been possible to fully adjust for the especially rapid increases in the cost of electric generating equipment.

The results of several of the forecasts from the pre-1976 period are summarized in Table 12.[16]

1. Hass

The Hass study covers the 13-year period between 1972 and 1985 rather than the 12-year, 1979 to 1990 period which is the standard for this study. To obtain a 12-year estimate from Hass's research, we might assume that his projected expenditures are spread equally over 13 years. Subtracting one-thirteenth of the total expenditure would leave a 12-year estimate of $578.7 billion in constant 1979 dollars. Alternatively,

TABLE 11

UNITED STATES DEPARTMENT OF ENERGY
FORECASTS OF ELECTRIC UTILITY CAPITAL NEEDS
January 1, 1978 to January 1, 1985

(billions of 1979 dollars)

	Generation*	Transmission & Distribution	Total
Medium Case	$ 168.4	$ 60.3	$228.7
Annual average	24.1	8.6	32.7
High Case	168.0	63.7	231.7
Annual average	24.0	9.1	33.1
Low Case	159.8	53.8	213.6
Annual Average	22.8	7.7	34.5
Electrical World, 1979-1984			
Annual Average	24.8	9.9	34.5
Boughman, Joskow & Kamat, 1979-1989			
Annual Average	16.3	14.6	30.0

* Includes conversions to coal and oil/gas interchange, and scrubber retrofit.

Source: Energy Information Administration, Annual Report to Congress, Vol. II (Washington, D.C.: U.S. Department of Energy, April 1978).

TABLE 12

SUMMARY OF FORECASTS OF CAPITAL NEEDS OF
THE U.S. ELECTRIC UTILITY SECTOR MADE PRIOR TO 1976

	RATE OF PEAK DEMAND GROWTH (%)	CUMULATIVE ESTIMATE OF CAPITAL NEEDS (Billions of 1979 $) **
Hass 1972-1985	6.9*	627.4
Temple, Barker & Sloane, Inc. 1979 to 1990 Baseline Forecast	5.3*	543.2
National Power Survey, 1979-1990		
Baseline	5.8	542.8
Low Growth	3.6	260.3
All Electric	9.4	1,183.0

*Capacity growth rate is used because peak demand is not available.

**Assumes 8 percent inflation in 1979.

Source: Jerome Hass, Edward Mitchell, and Bernice Stone, Financing the Energy Industry, (Cambridge: 1974), Ballinger Publishing Co.

Temple, Barker and Sloane, Inc., Economic and Financial Impacts of Federal Air and Water Pollution Controls on the Electric Utility Industry, Technical Report prepared for Environmental Protection Agency, Office of Planning and Evaluation, May 1976.

Federal Power Commission, National Power Survey, The Financial Outlook for The Electric Power Industry: The Report and Recommendations of the Technical Advisory Committee on Finance, U.S. Government Printing Office, December 1974.

subtracting actual 1972 capital expenditures yields a 12-year estimate of $600 billion. Because of Hass's optimistic expectations about demand growth, these 12-year estimates are much too high for the 1979 to 1990 period. However, they offer a reasonable benchmark for capital needs in any given 12-year period given Hass's growth assumptions. It must also be remembered that whenever there was a choice of alternative plausible assumptions, Hass chose the one that would have the highest implicit or explicit cost in order to "ascertain the extent to which financing problems might seriously threaten the ability of the energy industry to meet the demands placed on it."[17]

Hass's methodology involves three distinct steps: estimating production capacity growth and mix; estimating the cost of production capacity and associated transmission and distribution facilities; and combining the first two steps with an expenditure pattern to determine aggregate capital expenditures.

He assumed a decline in the 8.1 percent average annual rate (1950 to 1971) of increase in production capacity to 6.9 percent, and a continuation of the 6.9 percent average annual rate of growth in peak demand.[18] He also assumed that the mix of production capacity would shift toward nuclear generation--that between 1972 and 1990, 40 percent, and after 1990, half, of all new production facilities would be nuclear. These assumptions are not defended on cost or other grounds. However, they are comparable to then-available NPS estimates that by 1980, 22 percent, by 1985, 32 percent, and by 1990, 41 percent of total capacity would be nuclear.

Step two of the Hass forecasting procedure based the estimates of the cost of capacity expansion on 1973 surveys of electric utilities.

These estimates were increased to reflect coal plant desulfurization costs, thermal reduction apparatus for fossil-fired plants, and cooling facilities for nuclear plants. Transmission and distribution expenditures were then calculated as 120 percent of the cost per kilowatt of conventional plant and totalled with generation capacity estimates.

Finally, Hass calculated aggregate capital expenditure based on the number of kilowatts of capacity built, the cost per kilowatt of installed capacity each year, and the expenditure pattern. The number of kilowatts built combined the assumption of capacity growth with replacements based on a 30-year life and the historical growth rate of 7 percent. To reach a final cost estimate, Hass assumed that expenditures would be spread equally over five years. He recognized that the actual outlay period is longer than five years, particularly for nuclear plants, but argued that, "the rate of outlays is much higher in the last years of installing these plants; thus, the five years seems a reasonable estimate when combined with the assumption of equal payments each year."[19]

2. Temple, Barker and Sloane

The Temple, Barker and Sloane (TBS) forecast is based on a model initially constructed to provide projections for the Technical Advisory Committee on Finance of the 1973 National Power Survey. The model has three principal components of "modules": environmental, physical and financial. The general economic conditions and any other factors that determine the demand for electricity are considered exogenous to the model. Consumers' peak and average demand, target reserve margins, equipment mix, power drain, and the impact of pollution abatement regulations on generating efficiency are assumed and combined to determine capital needs.

The primary function of the environmental module is to introduce the assumed values of the model's exogenous variables. These include annual sales, peak demand growth, current and future pollution control requirements, operating and equipment costs, and the proportion of new nuclear capacity. TBS assumes an average annual growth rate for both electric sales and peak demand of 5.3 percent over the 1979 to 1990 period. Their estimates of capital needs for the early 1980's, however, are influenced by a forecast of construction starts in the late 1970's that is based on an even higher assumed growth rate (than that projected for 1979 to 1990).

The physical plant and equipment module determines the amount of generation capacity necessary to meet the demand assumptions at any time. In addition to demand level, the capacity calculation depends on desired reserve margins, and on various factors affecting generating efficiency as well as on retirements of old generating units. There is apparently no adjustment built into the model to allow for regional differences. The number of new plants assumed to be in construction at any time depends on the forecast of total additions to capacity, adjusted for the construction lag which differ by type of plant. The average construction lag is, therefore, a function of the assumed future mix of the various types of generating capacity.

The financial module of the TBS model converts physical capital needs to financial needs based on the proportions of conventional and nuclear plants to be built, the cost per unit of each type of asset, and the schedule of payments required by contractors while the plants are under construction.

The TBS model is continually revised, updated and reused. Despite the fact that it is among the most detailed models of the electric power industry available, however, its usefulness as a forecasting tool is limited. Since it is a recursive model, its results are heavily influenced by the initial assumptions. It is, therefore, probably best to think of the TBS procedures as being automatically calculated rather than "modeled."

In addition, the TBS model has no provision for changing relationships among capital expenditures for generating, and transmission and distribution facilities. The study identifies the share of total capital expenditures needed for transmission and distribution, but gives no indication of how capital requirements for these purposes have been determined. Furthermore, the model has limited value in analyzing regional capital needs, since it is unclear how it accounts for regional differences. This is especially troublesome given the shifting population and growing grid systems across the country and the likelihood that reserve margins will vary widely across regions.

3. The National Power Survey

By presenting a range of eight forecasts, three of which are included in Table 12, the 1974 National Power Survey (NPS) projections provide a benchmark from which the impact of the slower rate of growth on capital needs can be judged. The alternative NPS forecasts summarized here are their baseline, all-electric, and low-growth projections. In retrospect, the low-growth alternative may have been the most realistic.

All of the NPS forecasts for capital needs of the electric utility sector are based on the TBS model. However, these forecasts differ significantly in their assumptions relating to the growth in peak demand, the rate of construction cost escalation, and the impact of environmental requirements on capital costs. The NPS projections also tend toward the high side because they are based on expectations of more rapid growth in the 70's than actually occurred.

NPS's baseline forecast incorporates growth rates in peak demand that in 1973 were considered to be moderately high. Today they would be considered far too high. For the 1976 to 1980 period, (the decision period for capital expenditures in the early 80's) NPS assumed that peak demand would grow at an average annual rate of 6.5 percent, declining to 6.0 percent between 1981 to 1985, and 5.5 percent between 1986 and 1990. Construction cost escalation was assumed to follow what was labeled the "high" path, or about double the rate of increase assumed for the GNP deflator. For generating plants this meant a cost escalation of 7.5 percent per year between 1976 and 1980, falling to 5 percent thereafter. Transmission and distribution costs were assumed to increase at an average annual rate of 5 percent throughout the period. Looking back, of course, NPS's "high" construction cost escalation estimates seem rather modest.

Projected environmental protection costs are a third major source of difference among the NPS alternatives. The baseline assumptions are that these costs, which include cooling towers for fossil and nuclear plants and flue gas desulfurization (scrubbers), will follow a "low" path of increase (i.e., a 5.7-percent annual rate of increase between 1976 and 1980, and a 3-percent rate thereafter).

As in the baseline case, NPS's low-growth alternative also seems to lead to over-estimated near-term capital needs. It assumes an average annual growth in peak demand between 1976 and 1980 of 5 percent, which would lead to an overstatement of the requirements for the early 80's. However, the assumed growth rate falls to 4 percent between 1981 and 1985, and 3 percent between 1986 and 1990. It is, of course, still too early to know what the actual capital needs will be in the late 80's, but the assumed growth rate for the entire decade of 3.5 percent makes the NPS low-growth alternative a reasonable long-term guide, all other things being equal. The construction cost escalation path assumed for the low-growth alternative is the NPS "low" path, which assumes that construction costs in the 1980's will rise at an average annual rate of 3 percent, less than the rate of increase assumed for the GNP deflator. Environmental costs follow the "high" path which assumes an annual rate of increase of about 5 percent, somewhat above the assumed overall inflation rate.

Despite the low-growth alternative's relatively high assumed growth in peak demand for the late 70's, it is interesting to note that its estimate of average annual capital need in the 80's is $23.6 billion. If it is assumed that the low-growth case generates constant annual capital needs over the 1979 to 1990 period, this $23.6 billion estimate is about equal to the more recently prepared forecasts for 1979.

The NPS all-electric alternative is considered here for purposes of comparison. It is based on an assumed 8.0 percent annual rate of increase in peak demand through 1980, 10 percent between 1981 and 1985, and 9 percent thereafter. Construction costs increases are assumed to follow the high path, and environmental protection costs, the low path.

To make the NPS forecasts comparable to the others discussed in this report it was necessary to convert NPS's current dollar estimates into constant 1979 dollars. In all of the other cases, the conversion to 1979 dollars was made easier by the fact that the forecaster had reported the results in constant dollars, so only the base year had to be adjusted. Since some prices were assumed to be rising faster than the GNP deflator and others more slowly, the estimates given in the table should be viewed as only approximations of the NPS result. It was also necessary to adjust the forecast period to make the results comparable. The NPS results for the forecast period of 1980 to 1989 were extrapolated foreward and backward one year to derive the 1979 to 1990 forecast reported. Although NPS did not report annual estimates of electric industry capital needs, which probably increase over time, any bias introduced by extrapolation at one end is probably offset at the other end.

III. CONCLUSIONS

Forecasting the capital needs of the electric utility sector of the United States has become increasingly sophisticated over the decade of the 70's. Pre-1975 forecasts, such as NPS's and TBS's are primarily determined by exogenous assumptions. The most recent forecasts, (e.g.) BJK's or DRI's are still dependent on their assumptions, but they allow far more interaction among variables. The DRI forecast is perhaps the most independent of its assumptions since it is based on a simultaneous model that allows the preliminary results to feed back on the initial conditions. The BJK model, although based on externally assumed economic conditions, determines demand internally and bases the distribution of plant type on cost factors and construction lags rather than the assumed continuation of existing relationships. The DOE model is the most detailed, even though it currently relies on assumed macroeconomic conditions. It is probably also the most responsive to factors that affect the supply and demand for all types of energy products. Throughout the 1979 to 1990 period, however, because of the lags between initial planning and completion, all of the forecasts are heavily influenced by announced plans, work in progress, and the assumed rates of postponement and cancellation.

Perhaps the most striking conclusion of this analysis is that the estimates of capital need are relatively consistent irrespective of the estimation procedure. The EW subjective forecasts, the DRI simultaneous model, the BJK recursive model and the DOE linear programming model produce remarkably similar results. The variations that do exist seem to be primarily a result of differences in assumptions. Among the most important of these assumptions are the rate of increase in electric sales and peak demand, the mix of plant type, and assumed reserve margins.

A. Sales and Peak Demand

Regardless of whether the overall forecast is subjective or produced by a model, or whether the peak demand is assumed or derived, conclusions about peak demand are crucial to estimating capital needs. In most cases, the rate of growth in peak demand is either assumed or it is derived from an assumption or estimate of electric sales growth.[20] In those cases where peak is estimated on the basis of projected sales, the conversion usually depends on an assumption that load factors will continue at historic levels. Of the forecasters discussed in this report, only the *Electrical World* estimates electric sales and peak demand separately. *EW*, along with BTC, also predicts a deterioration in the load factor over time.

Even though the more recent forecasts incorporate peak demand growth rates which are significantly below those of earlier forecasts, some of these estimates of peak demand may still be too high. If peak demand grows more slowly than anticipated, the capital needs of the utilities will be reduced and reserve margins will continue to increase. In the short run, this could further delay plants in progress, or even result in some projects being abandoned. In the longer run, projects on the drawing boards might be postponed if not cancelled.

A recent study of the economic impact of alternative energy supply and demand assumptions by the Congressional Research Service of the Library of Congress indicates that 5 percent growth in electric sales and peak demand is the most that can be reasonably expected through 1990.[21] Estimates of more probable rates of future growth range between 4.1 and 4.3 percent per year, depending on assumptions about conservation, and oil prices, and availability. This conclusion is roughly consistent with the growth in peak demand projected by the more recent forecasts which range between 3 and 5 percent. Despite this general consensus, however, there is still considerable debate over the rate of future demand growth, with one side predicting an increase from the current "depressed" levels back toward 5 percent per year or more, and the other predicting growth rates between 3 and 4 percent. So long as high growth rates are expected, generation capacity will be increased to meet expected demand regardless of today's actual need. In all probability, these plants will then be brought on line regardless of actual demand.

B. Plant Mix

Another major determinant of differences in recent capital needs forecasts is the assumed mix of new generation plant between conventional and nuclear facilities. Of the studies reported here, the most thorough analysis of plant mix was done by BJK and DOE, although all of the estimates are heavily influenced by announced plans and work in progress. Table 13 summarizes the forecasts of nuclear generation capacity in service for several of the included studies. The breakdown is shown for only one of the older studies (TBS) to provide a means of gauging the impact of the reduced growth rates and skyrocketing nuclear construction costs.

TABLE 13

FORECASTS OF NUCLEAR GENERATION

CAPACITY AS A PERCENT OF TOTAL CAPACITY

FORECAST	1980	1985	1990	1995	2000
BJK	13	17	20	26	31
EW	11	16	20	30	na
DOE (Medium)	na	19	25	na	na
DRI	11	16	20	na	na
TBS	16	22	28	na	na

na: not available

Source: See text.

The recent estimates are of actual capacity in service, and therefore do not include nuclear facilities that are under construction, but have been postponed or delayed. The similarity of the estimates through 1985 is a reflection of the reliance placed on announced plans and work in progress in estimating additions to generation capacity. Moreover, since the EW and DRI estimates for 1980 were completed most recently, they therefore reflect the most recent delays, postponements and cancellations.[22] The DOE estimates are based on a linear program that is economically indifferent to new coal and new nuclear facilities. The arbitrary selection between these alternatives by the model reflects the difficult real world choice of utility executives. The model, however, unlike the executives, can fall back on announced plans in resolving the dilemma.

In view of the recent nuclear accident at Three Mile Island, all of the projections of future nuclear generation must be reconsidered. All of the plants scheduled to open by 1985 are probably fully committed although unaccounted-for construction problems could delay commissioning. Construction plans for 1990 and later may be more flexible. Some plants may be cancelled completely, while it may be possible to convert others to alternative fuels. If it is proven that the Three Mile Island accident was caused by avoidable human error and that new safeguards can prevent a recurrence, there may be no need to adjust present estimates. Indeed, in response to President Carter's energy message--it is even possible that nuclear generation may be accelerated.

C. Reserve Margins

Other differences among the recent capital needs forecasts reflect different notions about an appropriate target for reserve margins. Only the DRI model allows reserve margins to vary across the regions, and to fall as low as 15 percent.[23] As the capital needs of the electric utilities increase, reserve margin targets of 20 percent or more for all regions may be a luxury that the economy neither needs or can afford. As the industry adjusts to lower margins, capital needs for generation capacity will decrease, although capital requirements for distribution facilities may rise. These adjustments will be more likely if rising conventional fuel prices force increased construction of nuclear generating capacity, which for environmental and safety reasons is generally located in remote areas.

Reduced reserve margins do not necessarily imply reduced reliability. Even though the current reliability standard of one outage in ten years may seem impractically high, in view of the increasing costs of energy, it may be possible to maintain this standard through interties in and power sharing arrangements. An outage in one region could be covered by excess capacity in another in the same way individual companies and neighboring regions currently share power. There would undoubtedly be some risks to such a system, but these would have to be measured against the benefits of requiring less capital.

Finally, Table 14 summarizes the aggregate forecast of capital needs for each of the more recent studies included in this report and briefly characterizes them. The average annual rate of growth in peak demand is included as a rough guide to the assumptions behind the forecast, but should not be interpreted as the sole determinant of capital needs.

TABLE 14

SUMMARY OF FORECASTS OF CAPITAL NEEDS
OF ELECTRIC UTILITIES

FORECAST	TIME PERIOD FORECAST	CAPITAL NEED (billions of 1979 dollars)	RATE OF PEAK DEMAND GROWTH (percent)	FORECAST CHARACTERISTICS
BJK	1979-1990	453	4.1*	A
BTC	1979-1982	114	5.2*	B
DOE (reference)	1979-1985	229	4.8*	C
DRI	1979-1990	451	3.2*	D
EW	1979-1990	582	5.0	E

A. Analysis of electric sector of the U.S. economy based on assumed macroeconomic trends.

B. Analysis of energy sector of the U.S. economy given assumed macroeconomic conditions.

C. Analysis of energy sector of the U.S. economy given alternative DRI macroeconomic conditions.

D. Analysis of energy sector of the U.S. economy, based on conditions generated by linked macroeconomic model.

E. Subjective analysis of electric utility sector based on independent estimates of macroeconomic conditions.

*estimates (not given in study)

Source: See text.

FOOTNOTES

1. External financing refers to all funding outside of a company's own contribution from earnings.

2. Jerome Hass, Edward Mitchell, and Bernell Stone, Financing the Energy Industry (Cambridge, Mass: Ballinger), p. 84.

3. Bankers Trust Company, U.S. Energy and Capital: A Forecast 1978-82 (1978), p.17.

4. McGraw Hill, Electrical World, 29th Annual Electrical Industry Forecast, (September 15, 1978). This conclusion is indicated by a comparison of the data in Table 1 on external financing and the information on external and internal financing shares reported by Bankers Trust in U.S. Energy and Capital, p. 21. As Table 2 suggests, however, since 1972 these expenditures have increased very modestly as a share of total business expenditures for new plant and equipment.

5. DRI's forecast, which was made available for the purpose of this study, is not available to the public.

6. Electric Power in the United States: Models and Policy Analysis (Cambridge, MIT Press, forthcoming).

7. Energy Information Administration, Annual Report to Congress Vol. II (Washington, D.C.: U.S. Department of Energy, April 1978).

8. Electrical World predicts that real GNP growth will slow in 1979 from its 1978 pace, but does not anticipate a recession. Most of this slowing is a result of a decline in the rate of growth of consumer spending that is not made up by other sectors.

9. A previous study by Bankers Trust modeled the capital needs of energy industries through 1990 to test the assumed capabilities of the capital markets, but did not attempt to forecast conditions as they are likely to be.

10. BJK have made available for use in this study a draft of Chapter 9 which discusses financing the future growth of the electric power industry.

11. These assumptions include an interest cost of new debt of a 8.5 percent, an allowed rate of return on equity of 14 percent, a maximum proportion of debt allowed in the capital structure of 55 percent, and an interest coverage ratio that does not fall below 2.00.

12. See: Federal Energy Administration, Project Independence Evaluation System, Documentation: (Washington, D.C., 1976-1977), 14 Vols.

13. For a complete list of all the assumptions going into the DOE estimates, see: Energy Information Administration, Annual Report to Congress, 1977, Volume II, Appendix, Summary Data Inputs and Forecasts for 1985 and 1990 (Washington, D.C.: U.S. Department of Energy, September 1978), pp. 9-22.

14. For a complete list of assumed load duration curves by region and other data inputs, see Ibid, pp. B70-B93.

15. The following capital cost assumptions are national average values which are assumed to be the same as DOE Region V. The estimates are designed to reflect the cost of the average plant of each type delivered on December 31, 1984. These estimates include AFUDC (8%) and labor cost increases of 6.5 percent annually in nominal terms. The values for nuclear plants are national averages and not from DOE Region V.

Nuclear	$795
Coal with Scrubber	
Bituminous	600
Sub-bituminous	640
Coal without Scrubber	
Bituminous	485
Sub-bituminous	525
Combined cycle	340
Simple cycle	180
Oil	450
Scrubber retrofit	155

16. These results have been adjusted to 1979 dollars using the Gross National Product Implicit Price deflator, and are shown along with an estimate of the overall rate of growth in peak demand over the relevant forecast period in order to provide a basis for comparison. The actual GNP deflator is used for 1975-78. Estimation of the 1979 deflator assumes an 8 percent rate of increase. The inclusion of this estimate of peak demand growth, however, should not be interpreted as an indication that the forecaster based the estimate of capital needs only or primarily on peak demand.

17. Hass, op. cit., p. 1.

18. At the time, the 1970 National Power Survey (NPS) was forecasting a 6.0 percent rate of growth. A 6.9 percent estimate was generally throught to be high but conceivable.

19. Hass, op. cit., p. 118.

20. The DOE model achieves this distribution through an assumed load distribution curve based on historical data.

21. Alvin Kaufman, Warren Farb and Barbara Daly, Energy and the Economy, Subcommittee on Energy and Power, (Committee on Interstate and Foreign Commerce, U.S. House of Representatives, April 1978).

22. In determining the amount of capital needed for these additions to capacity, the forecasts differ because of different assumptions about the construction cost per kilowatt hour.

23. Differences in estimates of capital need that arise from divergent reserve margins, however, would become even more significant as the forecast period is extended.

PART II - REGULATORY RESPONSE TO THE INFLATIONARY ENVIRONMENT: SOME COSTS AND GAINS*

*This report was prepared at the National Regulatory Research Institute at The Ohio State University. The views expressed are those of the authors, Dr. Douglas N. Jones, Professor of Regulatory Economics; W. David Duran, Economist; and Curtis Odle, Economist, and do not necessarily reflect those of the Institute.

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I. INTRODUCTION

With the possible exception of the weapons acquisition process in the national security field, no sector in the U.S. economy has been so often characterized as "inherently cost-plus" as the public utility field; nor is this to be decried. Public utility regulation has historically placed great emphasis on cost, and where all legitimate business expenses are recoverable one-for-one from essentially captive customers this preoccupation is entirely appropriate. For this reason the current renewed attention to costs as exemplified in legislative (e.g., the National Energy Act), regulatory (e.g., time-variant cost determinations), utility (e.g., load management devices), and academic (e.g., marginal costing), activities should be applauded.

Emphasis on rates (or prices) that "track costs" is widely agreed to be the right pursuit. The main alternative--value of service pricing--while having special occasional usefulness in public utility rate design, carries with it special disadvantages in precision and equity. It should be mentioned too that "cost-plus" as used in describing public utility pricing need not be a pejorative term. In an idealized world of commission regulation, the overall revenue requirements for utilities should just cover all allowable costs of doing business, including debt service, and a fair return to useful capital actually (and prospectively) invested in the business. What this requires is a toughminded scrutiny of utility costs (and especially changes in costs) by regulatory commissions as well as a forward-looking analytical capability for judging consumer demand and appropriate utility company responses to meet that demand. It requires an informed balancing of short-term and (at least) near-term interests of ratepayers and shareholders where those interests diverge and are non-coincident. The pejorative use of the term comes when perceptions are that regulatory commissions are merely a conduit for "passing on" to ratepayers in an uncritical or unexamined way all price increases asserted to be faced by the utilities they regulate.

It is probably true that public attention to the regulated sector is generally related to the state of the national economy. In "good times," by which is meant rising real incomes, declining unemployment, relatively stable price levels, and regular productivity gains, there is understandably less of a focus on this orderly and essential sector. But in "bad times," like the depression of the 1930's and the sustained inflation of the last half of the 1970's, there is great attention to the behavior of the utility field. The regulatory response to this current period of intense and persistent upward pressures on prices is the central subject of this report; the possible regulatory response on the downside of price swings is a secondary subject.

The approach here is to first identify the main mechanisms and practices that commissions (and sometimes legislatures) have devised and adopted in response to a decade of inflation; second, to attempt to describe in a general way the costs and gains of this response; and third, to suggest the outlines of what the regulatory response might be when the economy returns to a period of relative price stability.

II. DEVICES AND PRACTICES

The categorization of particular regulatory devices as occasioning costs or gains to the several parties to the regulatory process is judgmental at best - especially if the element of time is considered. Still more elusive, but less consequential, is a distinction between regulatory "devices" and "practices." But for our purposes the notion of costs (and gains) will be from the vantage point of the ratepayer and the public administrator and will include both monetary and non-monetary "costs." The devices that are held to have placed the greatest near-term costs on regulation in the sense used here are fuel adjustment clauses and other indexing arrangements (like the New Jersey comprehensive adjustment clause and the New Mexico cost-of-service index provision); construction work in progress; normalization accounting treatment for investment tax credits and accelerated depreciation; reproduction cost new and fair value rate base valuations (over original cost and prudent investment methodologies); and emphasis on rate-of-return on equity over the rate-of-return on rate base standard.

A. Devices

The main devices that can be fairly arrayed on "the cost side" include increased use of future test years in cost-of-service calculations; allowing of pancaking of rate increases; use of interim rates; compressed time limits on commission deliberations; a quest for near-zero regulatory lag; internalizing external costs to the utility; and emphasis on the capital attraction standard (and risk avoidance) in ratemaking. Other lesser devices and practices that now characterize commission regulation will be discussed as well in terms of their contribution to costs and gains in an inflationary environment.

1. Automatic Adjustment Clauses and Fuel Adjustment Clauses (AAC's and FAC's)

Recall that definitionally an AAC is a provision in a utility company's rate schedule which allows a change in a particular cost item to be automatically (i.e., without commission hearings) reflected in the rates charged customers. By far the most common and now most burdensome AAC is that on fuel cost changes, though utility companies continue to propose other AAC's for changes in labor, taxes, interest and other costs of doing business.

Cases on the subject date back at least to World War II. Even after that time (and until quite recent years) FAC's were generally limited to industrial rate schedules and did not apply widely to residential consumers. That has now changed and nearly all states have AAC's and FAC's in one form or another with the blessing of the Federal Energy Regulatory Commission (FERC). Some 125 utilities began using FAC's in residential customers tariffs during the mid-1970's with 63 of them starting in 1974 alone. The main purpose of an AAC is to reduce so-called "regulatory lag" during periods when costs are rising rapidly: the main objection is that such arrangements may be incompatible with vigorous and effective rate regulation in the public interest.

For the 25-year period 1948 to 1973 the rate increases granted utilities by state and local jurisdictions totaled $6 billion. In the first year after the oil embargo (1974) consumers paid $9.6 billion attributable to general rate increases ($3.1 B) and the operation of FAC's ($6.5 billion).[1] FAC revenues in 1973 accounted for $1.5 billion in revenue.

Table 1 displays the dollar amounts[2] of general rate case increases granted in the utility industry under state commission regulation for the years 1974 through 1977 together with revenues attributable to the operation of FAC's over that period (for both electric and gas). The importance of FAC charges to utility revenues is indicated in part by the facts that the average shown here is some $9 billion per year; the FAC amount is 3 times the rate increase amount for the period; and in one period (1976-1977) the amount of general rate increases declined by $0.7 billion, while FAC amounts increased $1.4 billion. The cited survey also found that in 15 states FAC charges added more than $100 million to electric revenues and that FAC's accounted for more than 20 percent of electric receipts in a dozen states.[3] And this was at a time when state commissions were granting (on average for the two-year period 1975-1977) 50 percent of the amounts requested by utilities in rate cases, as against the two-thirds "typically" granted annually in recent years.

TABLE 1

GENERAL RATE INCREASES AND FAC REVENUES IN THE ELECTRIC AND GAS SECTORS, 1974-1977

(In Billions of Dollars)

Year		Revenues Attributable to FAC's	General Rate Increases
1974		$6.5	$3.1
1975		8.5	4.1
1976		9.6	3.1
1977		11.0	2.4
	Totals	$35.6	$12.7

Source: Footnote 3

The point here is simply that the proliferation and workings of fuel adjustment clauses in utility tariffs over the past seven years have, in general, yielded the revenue needed by the companies to maintain their financial positions. This was the stated object of FAC's, and despite a rocky road of consumer outcry, quarrels over what should and shouldn't be included in FAC's, the occasional outright "horror story"; on-going difficulties in verification and monitorship; and legitimate questions about the compatibility of automatic adjustment charges with full and open regulatory proceedings of the evidentiary variety, it seems fair to conclude that, in a rough way, FAC's worked for this period.

A related device with similar intent are several indexing schemes that have emerged--the most widely known being the New Mexico Cost-of-Service Index (COSI) now extended into its fourth year of operation.

Recall that this mechanism focuses on returns to equity and (in the case of Public Service of New Mexico) is supposed to result in a 14 percent rate of return on allocated common equity capital (at book value) after payment of all other cost of service. To achieve and maintain this net rate of return, automatic quarterly (now annual) adjustments in all base service rates were made to reach the nearest edge of the allowed range of 1/2 percent either side of 14 percent. Thus a return anywhere between 13.5 and 14.5 percent requires no adjustment in the succeeding period; a return above the upper limit requires a downward per kwh adjustment of rates to the upper limit; a return below requires an upward adjustment to the lower limit (not the middle) of the band. Importantly, fuel costs and purchased gas adjustments operate outside of COSI.

In December 1979, the New Mexico Commission concluded that, on balance, the methodology achieved its two primary objectives--"reduction of capital costs and the enhancement of PNM's ability to attract capital".[4] Accordingly, while still viewing COSI "as an experiment," the Commission extended it conditional on correcting some of the revealed deficiencies of the plan; e.g., inadequacy of reporting and procedural safeguards, overly burdensome to staff (instead of saving staff time), insufficient regulatory oversight by too frequent adjustments, inappropriate treatment of certain interest income and allocation factors.[5] A recently published report of The National Regulatory Research Institute concludes:

> On balance, it would appear that COSI has provided PNM with a temporary financial advantage that now seems to be past; increased, rather than decreased, regulatory costs; had no real impact on cost control or over-building; and has not resulted in PNM earning its minimum rate of return. It would thus appear that there is no advantage to the adoption of COSI by other jurisdictions.[6]

The most recent notable wrinkle in automatic adjustment clauses is the Michigan Indexing Method introduced in 1979.[7] The Michigan Public Service Commission order allows a company to make an annual (every February) automatic adjustment of operating and maintenance expenses (other than fuel and purchased power costs) in accordance with changes in the national Consumer Price Index. Qualifying increases would appear as a kWh surcharge on customer bills; increases greater than the CPI would be charged below the line. The idea is that by making automatic revenue adjustments contingent on retail price changes in the economy rather than on utility-incurred costs, there may be external pressures on company management to "out-perform" (or at least perform as well as) the CPI. It is estimated that about two-thirds of utility costs would be recovered under this scheme without the requirement of a rate hearing.

However all this may be, the fact of automatic adjustment clauses with the support they draw from utilities and opposition from ratepayers in the first instance and the switching of positions that describes the stances of the two parties when AAC's are attempted to be made more stringent (like fuel cost disclosure) indicate that at least in the near term, such devices are a blessing to the utilities in periods of sustained inflation.

2. Construction Work in Progress (CWIP) and Normalization Accounting

Historically the "used and useful in doing business" test precluded the allowance of CWIP in the rate base. At least into 1976 the Federal Power Commission and many states disallowed inclusion of CWIP in the rate base of utilities. Instead, allowance for funds used during construction

(AFUDC) was typically the approved method. The AFUDC approach provides a non-cash item of "current income" that the utility adds onto the cost of a facility when it is completed; the CWIP approach allows the company to earn on "the asset" along the way before it is in service.

The argument was that AFUDC was perhaps an acceptable procedure where the overstatement of current income (and hence cash flow) was a relatively small proportion of reported earnings. Once AFUDC came to represent one-third of utility net income, as had happened by 1974, the illiquidity (and other financial) problems for the industry became acute in the face of major, costly, continued construction.

That the FPC and subsequent state commission inclusion of CWIP in rate base makes a great difference is evidenced by (for example) a Library of Congress study that concluded that overall rate levels would rise about 9 percent (by swapping AFUDC for CWIP) and an FPC economic report that estimated the cost for the period 1975 - 1979 to be $22 billion if all states and the FPC adopted CWIP.[8]

What can be said for our purposes here is that of all the arguments of utility proponents of CWIP (the municipals and cooperatives have generally opposed CWIP), probably the least persuasive is that rate-payers ultimately would pay less under this arrangement. CWIP is, in fact, another regulatory response to inflation of particular helpfulness to the utilities.

3. <u>Normalization and Flow-through; Accelerated Depreciation and Investment Tax Credits</u>

Normalization and flow-through are two typical methods of accounting for the main government subsidy provisions in the Internal Revenue Code now applied to utilities - accelerated depreciation (AD) and the investment tax credit (ITC). Briefly put, under the flow-through method the benefits of the tax reduction deriving from AD and/or ITC are immediately passed on to the ratepayer in the form of lower rates (since taxes as an operating cost are reduced). Under normalization, the benefits to the utility are an increased cash flow through deferred tax payments while charging the deferred cost to ratepayers.

As to the effect on rates, critics of normalization accounting argue (among other things) that ratepayers are hurt by paying rates that include taxes all year long only to have the utility not pay them at tax time as the utility's tax liability is reduced--or indefinitely deferred. Proponents assert that normalization lowers rates "in the long run." The sums involved are very large. Electric utility industry spokesmen themselves estimate that normalization leaves with utilities an extra $3 billion annually in "internally generated funds."[9]

The whole question of so-called "phantom taxes" occurring through use of normalization accounting applied to accelerated depreciation and investment tax credits in determining a utility's federal income tax liability is admittedly an extremely complex one. AD and ITC were originated by the Congress as part of a macroeconomic policy to spur the U.S. economy forward. Their application to the public utility sector, where investment decisions are supposed to be made primarily on need (and not on the artificially created opportunity for lower cost money) and where state public utility commissions historically decided on what accounting methods would be allowed utilities under their jurisdiction, was perhaps less well thought out than it might have been. While not quite an "afterthought," it is clear that the Congress' focus was not on this sector.[10] In all events, once the ITC and AD provisions were decided to be applied at all to public utilities and subsequently to apply with the same full force as to the rest of the private sector, these devices became sources of benefits that investor-owned utilities would understandably be slow to give up.

While it should be mentioned that at this writing the California PUC has so far successfully struck down the combination of normalization with AD and ITC for utilities under its jurisdiction, the issue is in the appeals courts and is being carefully watched by other commissions. Also the National Association of Regulatory Utility Commissioners recently (March 1979) testified against normalization as "bad anti-inflation policy, bad energy policy, and bad regulatory policy."[11] Yet, as of 1978, the vast majority of jurisdictions (about 40) permit utilities to keep the tax benefits through normalization.

There seems little argument that these particular accounting and tax features are additional devices made available as a regulatory response to inflation, though their legislative origins were quite different from that.

4. <u>Rate Base Valuations and Rate-of-Return Determinations</u>

The old issue of valuing the rate base of a utility by the Reproduction (or Replacement) Cost New method or the Original-Cost-Plus-Improvements-Minus-Depreciation method is currently relatively quiet; but it should be remembered that in periods of declining prices the utilities generally favor the latter and periods of sharply rising prices generally advocate the former. Actual changes in methods allowed can and do go either way--Ohio, for example, having recently become an Original-Cost state. Still, it is felt by some that the new push for the use of marginal cost, over imbedded cost, in rate design is the current counterpart to the earlier argument.

However this may be, it is clear that where marginal cost is running ahead of average cost for sustained periods and sometimes at an increasing pace, utility revenues presently would be greater and allowable rates of return more likely to be earned if MC pricing was allowed instead of AC pricing. Indeed, a good bit of the argument over whether or not to go to MC pricing centers on the question of what to do about (or how to avoid) excess revenues. For this reason it is sometimes puzzling why the electric utility sector has so far been slow to embrace the marginal cost pricing approach.

If the method of rate base valuation can be properly characterized as having attracted relatively less attention in recent years, surely this cannot be said of rate-of-return on rate base or on equity in this period of inflation. As to allowable rates-of-return on rate base, the decade of the 1970's has seen these percentages move steadily upward. Of the approximately two hundred electric (and gas) utilities surveyed annually from 1974 to 1978, a rising pattern is clear.[12] In 1974 the average was about 7 percent with a few at 5 percent; in 1975 the average was 8.24 percent (the average allowable rate requested was 8.61 percent); by 1976 the average of reporting utilities was 8.30 percent, but with 141 companies allowed 9 percent or more and 49 utilities allowed to earn in excess of 10 percent on rate base. In that same year some utilities in four states requested allowed return on equity of 15 to 20 percent. Finally, for 1977 the average allowed rate-of-return reported was 9 percent. Over this period many utilities did not earn their allowed rate, and in fact for the data series mentioned the actual rate-of-return on rate base was typically around 7 percent in 1974 and had increased to something over 8 percent for 1977.

Of perhaps more significance is the apparent trend of commissions to give relatively more attention to questions of rate-of-return on equity. This focus has long been the one argued for by the regulated utilities as opposed to what they historically feel as undue commission preoccupation with rate-of-return on rate base calculations. And in a period of sustained inflation coupled with perceived needs for plant expansion, it is understandable that utilities argue strongly for renewed attention to the "capital attraction" standard of ratemaking.* That commissions have generally responded toward this different focus is another example of the regulatory response to inflationary times.

B. Practices

Turn now to some of the more recent practices of commission regulation--a number of them legislatively or administratively imposed--that for purposes here can be counted on the "cost side" to traditional regulation.

1. Future Vs. Historical Test Years

Traditionally commissions allowed only current test years to be used in calculating revenue requirements for utilities. This meant that only costs actually incurred were recovered. Gradually, as persistent upward changes in price levels set in, and under urgings of the utilities, commissions came to grant "trended" cost calculations; estimated future quarters to be rolled in and revised as each actual quarter is experienced; and then whole future test years as the basis for revenue requirements. And if marginal costing is adopted, the upward bias arising out of allowing future test years is, of course, further accentuated in periods of rising prices.

Deviations of this sort from the practice of allowing recovery of costs only for those actually experienced is clearly a practice spawned by inflationary times and adopted under utility arguments of regulatory and cash flow difficulties.

*While the two measures are of course related, the necessary return to common stock is only a part of the overall cost of capital component and rate-of-return determination.

2. Pancaking, Interim Rates, and Time Limits

At an earlier time utilities were typically not allowed to "pancake" proposed rate increases. That is, a commission had to dispose of a current general rate increase before another one could be requested by the utility. Due deliberation, comprehensive and fair evidentiary hearings, and even strategic delays were thus possible in the full playing out of the intended regulatory process.

Again using arguments of undue regulatory lag, financial soundness of the regulated companies, cash flow constraints, and a presumed necessary "discipline" for the regulators, the commission process has now widely accepted contrary practices like allowing pancaking of rate increases; a presumption in favor of proposed increases, (allowing them to go into effect if not specifically struck down); frequent use of "interim rates" and "emergency rate relief"; and strict (short) time limits for commission action to achieve almost zero regulatory delay.

From the point of view of the process and from the point of view of the ratepayer, these practices in times of inflation must be counted on "the cost side."

3. Internalizing External Costs

The increasingly frequent practice of internalizing to utilities external costs deriving from their operations cannot properly be included as part of the regulatory response to inflation. On the other hand, decisions to force onto the private cost functions of companies what earlier had been picked up in our social cost functions has added substantially to the cost of doing business--hence costs to the ratepayer--of power companies. Elaborate environmental and safety additions to plant, purchased and operated often at vast expense, may not fit neatly the traditional "used and useful" test in the central matter of producing electricity, however meritorious the intended ancillary benefit. And while it is, of course, true that such costs are real and have to be absorbed by somebody, the point is that they are different "somebodies," depending on the distribution of the burden.

4. Capital Attraction and Risk Avoidance

During periods of relatively stable prices and "ordinary times," utilities routinely argue before commissions for improved earnings commensurate with their perceived riskiness and forecast capital needs; commissions respond with something less than requested; investors place money in capital markets such that the utilities are reasonably serviced in their new finance capital requirements; and "life goes on" in the electric power sector. In times of sustained and rapid inflation, however, the story is much different on matters of capital attraction and risk adoption.

In "bad times" of this sort with high unit costs of expansion, high capital costs in finance markets, stock and bond markets that value utility issues very competitively, there are special efforts made by utilities to convince public officials of the need for liberalized earnings. This takes many forms (including most of those devices and practices mentioned above) and involves not only public utility commissions. The Congress in its tax writing function has granted various tax preferences (e.g., AD and ITC, supra) and has also considered underwriting utility bond issues as well as possibly reactivating something like the Reconstruction Finance Corporation with lending powers to the utilities. For their part, commissions increasingly are sympathetic to utility arguments couched in the capital attraction standard and this is set at the forefront of most commission deliberations.

The other side of this coin is the complicated question of risk-bearing. There is some evidence that in recent years degrees of risk-bearing in the utility sector seem to have shifted somewhat from shareholders to ratepayers. An example would seem to be the regulatory treatment of unplanned plant shutdowns of either the nuclear or non-nuclear variety.

Some distinctions must be made between cost-bearing in the case of an Act-of-God, say a typical power outage when lightning strikes a transformer, and a major sustained shutdown of plant through mis-specification, mis-design, mis-management, or construction or operating mistakes assignable to one or another party. In the former case (as well as in the case of planned shutdowns) it is clear that the ratepayer should stand these costs: in the latter case it is a good bit less clear where, of all the parties to the process, the ratepayer would seem to be least culpable. Some mix of burden sharing may be best here--among ratepayers, shareholders, managers, suppliers, insurance companies, taxpayers.

On the other hand, to count this asserted development on "the cost side" of changes in regulatory practice assumes that returns to stockholders for risk-bearing are not currently too low to begin with. In other words, it would obviously be unfair for regulatory bodies not to permit rates-of-return to equity holders high enough to be commensurate with the risks involved and then make those same shareholders bear the burden alone when risk becomes reality. Since whether or not risk and returns are now in equilibrium in the utility sector is not a demonstration of this part of the report, the practice cited is only provisionally included here.

In addition to the "main devices and practices that seem to have accompanied regulation in a period of inflation there are several others that might be identified. Some of these have been commission-sanctioned, some legislatively initiated, and some seem almost endemic to regulation and are not very susceptible to policy resolution.

In the first category should be placed the debate on changing the interest rate charged on refunds paid by private power companies to customers in adjusting for overcharges. For the wholesale market the issue before the FERC is whether to raise the rate from 9 percent out to the average prime rate charged by commercial banks (11.5% to 11.75%); raise it to the prime rate plus a 1 percent penalty charge (as proposed by the American Public Power Association); or drop the rate to the 7 percent level set in 1971, as urged by major investor-owned utilities.[13] The outcome will determine if this device is counted on "the cost side." Also in this first category should be the debate (and outcome) on whether or not fuel cost data of private utilities must be publicly disclosed for all to see.

In the second category could be mentioned the propensity for legislatures to reach deeply and specifically into commission regulation altering, some would say, the traditional concept of a contemplative, quasi-judicial, independent body. Done in the name of "increased responsiveness," legislatures now commonly pass laws "for" so-called lifeline rates or "against" fuel adjustment charges. While commissions are, of course, creatures of legislatures (state and national), this new development to some extent has brought regulation full circle to the days when legislatures (and city councils) decided very specific regulatory issues of rates and routes and service offerings. Whether or not this practice should be counted as "a cost" to regulation depends largely upon ones basic view of the commission concept. For purposes here it is considered a cost; similarly with legislative initiatives to require election of state public utility commissioners.

At least two items come to mind for that category of "practice" described as containing perennial difficulties for regulation. Both of these are all the more troublesome - and consequential - in periods of sustained inflation. One is the problem of plant expansion decisions. In a sector where willingness and ability to serve demand is an absolute it is not surprising that there is a predisposition to build - with or without an "A-J effect."* And where commissions are unable or unwilling to secure independent assessments of demand on which utility investment decisions are based, there is a potential for adding another practice to "the cost side".

The other (and perhaps related) practice is that of valuing reliability over price. This tendency or proposition includes not only the issue of gold-plating and unduly stringent outage measures, but also the demonstrated willingness of utilities to pay a premium price for a reliable source of fuel supply even if they do not have automatic fuel adjustment clauses in their tariffs.[14] However meritorious this posture might be on reliability grounds, it seems fair in the near term to count this on "the cost side".

III. GAINS FROM COSTS

In a regulated market it is proper that much if not most of the attention of the parties should be on the financial performance of the industry where service is a given. Accordingly, many (though not all) of the devices and practices identified in the previous section as "costs" in a period of inflation could as well be labeled as gains from the point of view of the electric power industry and even from the vantage point of the ratepayer. This last is the case where maintaining or renewing the financial soundness of particular utilities has been the issue during a time of sharply and persistently rising prices. In this sense the regulatory response of the past decade could be said in a general way to be appropriate and perhaps even sufficient.

Some sense of this renewal (however imperfectly measured) can be gotten from the two sub-reports made by different authors that follow here as Sections A and B. The first deals with the convergence of market value on book value for representative utilities since the oil embargo; the second

*This refers to the inclination of utilities to expand rate base investment (and thus earnings) beyond the optimally efficient size.

presents some data on productivity changes in the utility industry--so closely related to the inflation problem.

A. Convergence of Market Value on Book Value*

In the following nine tables are gathered some financial information on thirty-one large privately owned electric utilities and nine electric utility holding companies. Table 2 shows the ratio of market to book value while Table 3 shows the percentage change in the ratio of market to book value over the years. Tables 4 and 5 respectively show the yearly percentage change in earnings per share and the percentage change in dividends. Table 6 shows the average price-earnings ratio over an eight-year period. Table 7 shows the rate of return on common stock equity over a seven-year period and Table 8 shows the yearly percentage change in this measure. Finally, Tables 9 and 10 show respectively the rate of return on rate base and percentage change in the rate of return on rate base over a seven year period.

The ratio of market value to book value (shown in Table 2) was gathered for a nine-year period, 1970 through 1978. The book values are from the end of the previous year and the market values are from August 26 of the year stated or closely around this date. The thirty-one electric utility companies are arranged alphabetically with an average given for each year. The nine electric utility holding companies are then shown and again an average is given for each year.

In 1970 and 1971 the ratio of market to book value was greater than one for most firms with an average of approximately (due to rounding throughout) 1.33 in 1970 and 1.31 in 1971 for electric utilities. By 1972 this ratio had dropped to 1.16. Much more substantial drops occurred between '72 and '73 and '73 and '74 where this ratio was at its low point for most of the electric utility companies in the nine year period. In '75, '76, and '77 the ratio

*This section was prepared by Mr. W. David Duran, Economist and Graduate Research Associate, National Regulatory Research Institute staff.

TABLE 2

RATIO OF MARKET TO BOOK VALUE OF FORTY UTILITY STOCKS, 1970 TO 1978 TAKEN ANNUALLY IN AUGUST

ELECTRIC UTILITIES	1970	1971	1972	1973	1974	1975	1976	1977	1978
Arizona Public Service Co.	.98	1.04	1.01	.88	.67	.72	.82	1.01	.91
Baltimore Gas & Electric Co.	1.23	1.21	1.12	.93	.52	.72	.87	.93	.88
Boston Edison Co.	.97	.97	.90	.90	.40	.50	.53	.58	.56
Cincinnati Gas & Electric Co.	1.52	1.42	1.25	1.13	.79	.81	.89	1.09	1.01
Cleveland Electric Illuminating Co.	2.13	2.15	2.07	1.78	1.23	1.34	1.41	1.59	.84
Commonwealth Edison Co.	1.20	1.16	1.07	.84	.59	.65	.76	.73	.66
Consolidated Edison of New York, Inc.	.75	.81	.81	.70	.22	.33	.46	.55	.54
Consumer Power Co.	.96	.86	.79	.67	.31	.42	.56	.64	.64
Dayton Power & Light Co.	1.30	1.38	1.26	1.07	.67	.84	.97	1.02	.87
Detroit Edison Co.	.79	.87	.82	.75	.39	.51	.60	.71	.66
Duquesne Light Co.	1.36	1.42	1.31	1.40	.82	.82	.92	.96	.81
Florida Power & Light Co.	3.43	3.15	1.39	1.25	.53	.66	.68	.58	.71
Florida Power Co.	1.80	1.43	1.29	.99	.39	.61	.67	.89	.66
Illinois Power Co.	1.60	1.54	1.23	1.04	.70	.87	.96	.99	.86
Indianapolis Power & Light Co.	1.23	1.28	1.20	.98	.71	.81	.88	.98	.84
Long Island Light Co.	1.27	1.30	1.25	1.02	.60	.76	.90	.99	.97
New York State Electric & Gas Corp.	1.51	1.65	1.46	1.29	.87	1.03	1.31	.90	.85
Niagara Mohawk Power Corp.	.87	.96	.93	.86	.54	.66	.77	.94	.84
Northern States Power (Minn.)	1.14	1.17	1.10	.95	.67	.76	.87	.93	.78
Ohio Edison Co.	1.49	1.44	1.38	1.22	.84	.95	1.05	1.13	.99
Oklahoma Gas & Electric Co.	1.99	1.90	1.77	1.41	1.03	.99	.89	.90	.84
Pacific Gas & Electric Co.	1.07	1.10	1.05	.85	.70	.73	.75	.85	.82
Philadelphia Electric Co.	1.02	1.08	1.08	.94	.53	.67	.75	.95	.78
Public Service Company of Colorado	1.07	1.17	1.00	.81	.54	.72	.78	.93	.85
Public Service Electric & Gas Co.	.99	1.08	.96	.85	.50	.60	.75	.86	.80
South Carolina Electric & Gas Co.	1.34	1.14	1.10	.86	.50	.69	.79	.85	.74
Southern California Edison Co.	.99	1.05	.89	.67	.56	.57	.61	.78	.74
Tampa Electric Co.	1.87	1.70	1.34	1.16	.61	.80	.82	.84	.57
Union Electric Co.	1.18	1.18	1.07	.99	.73	.83	.96	.96	.87
Virginia Electric & Power Co.	1.20	1.06	1.00	.87	.45	.60	.74	.76	.71
Wisconsin Electric & Power Co.	.97	.92	.92	.91	.68	.95	.99	1.03	.92
Averages	1.33	1.31	1.16	1.00	.62	.74	.83	.90	.79
ELECTRIC UTILITY HOLDING COMPANIES									
Allegheny Power System, Inc.	1.22	1.19	1.11	.96	.70	.71	.81	.89	.76
American Electric Power Co.	1.33	1.37	1.31	1.11	.61	.82	.98	1.04	1.00
Central & Southwestern Corp.	3.52	3.39	3.22	1.28	.77	.85	.82	.86	.78
General Public Utilities Corp.	.92	1.07	.98	.83	.47	.66	.76	.85	.73
Houston Industries	2.13	2.13	2.06	1.34	.70	.63	.76	.93	.81
Middle Southern Utilities, Inc.	1.43	1.36	1.20	1.07	.47	.61	.68	.74	.69
New England Electric System	.91	.99	1.01	.87	.48	.62	.72	.78	.75
Southern Co.	1.09	.96	.88	.72	.45	.55	.65	.74	.66
Texas Utilities Co.	4.11	4.48	2.11	1.66	1.08	.94	.96	1.02	.96
Averages	1.85	1.88	1.54	1.09	.64	.71	.79	.87	.79

TABLE 3

PERCENT CHANGE IN RATIO OF MARKET TO BOOK VALUE OF FORTY UTILITY STOCKS, 1970 TO 1978 TAKEN ANNUALLY IN AUGUST

ELECTRIC UTILITIES	70-71	71-72	72-73	73-74	74-75	75-76	76-77	77-78
Arizona Public Service Co.	6.1	- 2.9	-12.9	-23.9	7.5	13.9	23.2	- 9.9
Baltimore Gas & Electric Co.	- 1.6	- 7.4	-17.0	-44.1	38.5	16.7	6.9	- 5.4
Boston Edison Co.	0.0	- 7.2	0.0	-55.6	25.0	6.0	9.4	- 3.4
Cincinnati Gas & Electric Co.	- 6.6	-12.0	- 9.6	-30.1	2.5	9.9	22.5	- 7.5
Cleveland Electric Illuminating Co.	0.0	- 3.7	-14.0	-30.9	8.9	5.2	12.8	-47.2
Commonwealth Edison Co.	- 3.3	- 7.8	-21.5	-29.8	10.2	16.9	- 3.9	- 9.6
Consolidated Edison of New York, Inc.	8.0	0.0	-13.6	-68.6	50.0	39.4	19.6	- 1.8
Consumer Power Co.	-10.4	- 8.1	-15.2	-53.7	35.5	33.3	14.3	0
Dayton Power & Light Co.	6.2	- 8.7	-13.0	-37.4	25.4	15.5	5.2	-15.0
Detroit Edison Co.	10.1	- 5.7	- 8.5	-48.0	30.8	17.6	18.3	- 7.0
Duquesne Light Co.	4.4	- 7.7	6.9	-41.4	0.0	12.2	4.3	-15.6
Florida Power & Light Co.	- 8.2	-55.9	-10.1	-57.6	24.5	6.1	-14.7	22.4
Florida Power Co.	-20.6	- 9.8	-23.3	-60.6	56.4	9.8	32.8	-23.0
Illinois Power Co.	- 3.8	-20.1	-15.4	-32.7	24.3	10.3	3.1	-13.0
Indianapolis Power & Light Co.	4.1	- 6.3	-18.3	-27.6	14.1	8.6	11.4	-14.3
Long Island Light Co.	2.4	- 3.8	-18.4	-41.2	26.7	18.4	10.0	- 2.0
New York State Electric & Gas Corp.	9.3	-11.5	-11.6	-32.6	18.4	27.2	-31.3	- 5.6
Niagara Mohawk Power Corp.	10.3	- 3.1	- 7.5	-37.2	22.2	16.7	22.0	-10.6
Northern States Power (Minn.)	2.6	- 6.0	-13.6	-29.5	13.4	14.5	6.9	-16.1
Ohio Edison Co.	- 3.3	- 4.7	-11.6	-31.1	13.1	10.5	7.6	-12.4
Oklahoma Gas & Electric Co.	- 4.5	- 6.8	-20.3	-27.0	- 3.9	-10.1	1.1	- 6.6
Pacific Gas & Electric Co.	2.8	- 4.5	-19.0	-17.6	4.3	2.7	13.3	- 3.5
Philadelphia Electric Co.	5.9	0.0	-13.0	-43.6	26.4	11.9	26.7	-17.9
Public Service Company of Colorado	9.3	-14.5	-19.0	-33.3	33.3	8.3	19.2	- 8.6
Public Service Electric & Gas Co.	- 9.0	-11.1	-11.5	-41.2	20.0	25.0	14.7	- 7.0
South Carolina Electric & Gas Co.	-14.9	- 3.5	-21.8	-41.9	38.0	14.5	7.6	-12.9
Southern California Edison Co.	6.0	-15.2	-24.7	-16.4	1.8	7.0	27.9	- 5.1
Tampa Electric Co.	- 9.1	-21.2	-13.4	-47.4	31.1	2.5	2.4	-32.1
Union Electric Co.	0.0	- 9.3	- 7.5	-26.3	13.7	15.7	0.0	- 9.4
Virginia Electric & Power Co.	-11.7	- 5.7	-13.0	-48.3	33.3	23.3	2.7	- 6.6
Wisconsin Electric & Power Co.	- 5.2	0.0	- 1.1	-23.3	39.7	4.2	4.0	-10.7
Averages	- .82	- 9.2	-14.3	-41.5	22.1	13.4	9.7	-10.2
ELECTRIC UTILITY HOLDING COMPANIES								
Allegheny Power System, Inc.	- 2.5	- 6.7	-13.5	-27.1	1.3	4.2	9.9	-14.6
American Electric Power Co.	3.0	- 4.4	-15.3	-44.1	32.3	19.5	6.1	- 3.8
Central & Southwestern Corp.	- 3.7	- 3.0	-60.2	-39.8	10.4	- 3.5	4.9	- 9.3
General Public Utilities Corp.	16.3	- 8.4	-15.3	-43.4	40.4	15.2	11.8	-14.1
Houston Industries	0.0	- 3.3	-35.0	-47.8	-10.0	20.6	22.4	-12.9
Middle Southern Utilities, Inc.	- 4.9	-11.8	-10.8	-56.1	29.8	11.5	8.8	- 6.8
New England Electric System	8.8	2.0	-13.9	-44.8	29.2	16.1	8.3	- 3.8
Southern Co.	-11.9	- 8.1	-18.2	-37.5	22.2	18.2	13.8	-10.8
Texas Utilities Co.	- 4.9	-52.9	-21.3	-39.2	-13.0	2.1	6.3	- 5.9
Averages	.2	-10.7	-19.6	-42.2	15.9	11.5	10.3	- 9.1

Sources for Table 2 and Table 3

Standard and Poor's Industry Surveys Utilities Electric, March 30, 1978 (Section 3) and Wall Street Journal for the dates, August 25, 1978, August 26, 1977, August 26, 1976, August 26, 1975, August 25, 1974, August 27, 1973, August 25, 1972, August 26, 1971, August 26, 1970.

TABLE 4

PERCENT CHANGE IN EARNINGS PER SHARE

ELECTRIC UTILITIES	70-71	71-72	72-73	73-74	74-75	75-76	76-77
Arizona Public Service Co.	0.0	31.6	14.8	-11.0	11.1	- 5.0	22.3
Baltimore Gas & Electric Co.	0.7	1.4	4.6	- 3.4	- 3.8	13.5	- 8.3
Boston Edison Co.	6.0	1.1	-18.9	- 9.7	- 4.2	9.2	-24.3
Cincinnati Gas & Electric Co.	- 6.0	15.2	- 4.3	-15.9	- 1.6	- 2.1	52.2
Cleveland Electric Illuminating Co.	1.5	5.4	- 5.9	20.7	-13.9	12.7	22.3
Commonwealth Edison Co.	- 3.1	9.4	1.0	- 8.9	2.4	8.5	-10.3
Consolidated Edison of New York,Inc.	2.2	-11.9	13.0	14.5	39.6	11.8	8.4
Consumer Power Co.	- 8.8	1.1	-11.4	-44.4	97.8	37.0	-12.4
Dayton Power & Light Co.	- 3.7	3.9	-13.0	1.1	18.5	- 8.5	-17.0
Detroit Edison Co.	- 3.7	15.5	-18.1	-17.5	2.7	10.7	10.8
Duquesne Light Co.	3.3	6.8	0	- 1.7	3.0	-17.7	-10.3
Florida Power & Light Co.	29.2	5.0	14.9	-21.7	26.1	-31.3	59.4
Florida Power Co.	1.9	12.7	- 4.0	-18.8	66.1	-20.1	50.1
Illinois Power Co.	-15.2	- 2.9	5.5	-10.0	19.9	-11.0	26.0
Indianapolis Power & Light Co.	12.7	27.8	-11.2	-26.8	23.6	6.8	32.9
Long Island Light Co.	8.2	4.3	- 7.7	0	13.8	8.1	2.8
New York Electric & Gas Corp.	- 9.6	19.5	- 1.5	12.1	- 3.6	6.0	- 3.1
Niagara Mohawk Power Corp.	- 0.7	23.1	-23.2	22.3	19.4	-20.7	8.1
Northern States Power (Minn.)	5.4	8.3	- 5.1	- 8.0	22.9	- 0.7	0.7
Ohio Edison Co.	- 3.2	7.3	12.0	- 20.1	14.0	9.7	-12.1
Oklahoma Gas & Electric Co.	- 1.7	10.1	1.6	2.6	- 2.1	- 2.1	7.5
Pacific Gas & Electric Co.	11.3	9.8	7.0	1.2	-18.3	8.6	8.6
Philadelphia Electric Co.	14.1	- 1.0	- 4.3	- 9.0	2.8	2.7	- 2.1
Public Service Company of Colorado	- 1.0	11.7	4.5	-20.0	29.2	- 9.7	-19.9
Public Service Electric & Gas Co.	22.0	-23.7	- 3.9	6.8	- 4.3	2.7	0.4
South Carolina Electric & Gas Co.	-14.0	36.1	-11.6	- 9.7	32.3	- 5.7	16.8
Southern California Edison Co.	- 8.9	3.7	5.9	51.9	-25.1	20.5	4.9
Tampa Electric Co.	-31.7	67.0	2.4	-12.9	31.8	- 2.6	21.1
Union Electric Co.	-16.1	-16.1	16.2	-16.0	29.9	4.5	-10.2
Virginia Electric & Power Co.	4.5	12.4	2.4	-23.9	20.4	- 7.7	7.8
Wisconsin Electric Power Co.	- 5.8	36.0	9.1	-10.8	- 1.2	25.6	5.3
Averages	- .1	10.5	- 1.2	- 5.7	14.6	1.0	7.5
ELECTRIC UTILITY HOLDING COMPANIES							
Allegheny Power System, Inc.	5.9	5.6	2.6	-23.6	41.6	3.6	- 9.2
American Electric Power Co.	5.7	8.2	8.4	-29.5	24.4	6.4	- 9.0
Central & Southwestern Corp.	4.9	8.7	5.5	2.3	- 2.3	1.7	17.1
General Public Utilities Corp.	15.6	17.9	1.8	0	-11.1	10.0	11.8
Houston Industries	10.9	9.1	- 1.6	- 4.3	- 6.8	47.4	9.2
Middle Southern Utilities, Inc.	4.3	17.9	5.6	5.7	-23.1	7.1	21.4
New England Electric System	6.1	21.4	- 7.8	- 3.4	9.3	2.0	7.9
Southern Co.	- 8.8	6.2	10.1	-31.9	60.3	-27.0	14.5
Texas Utilities Co.	4.8	12.1	3.1	8.5	- 7.3	13.4	3.1
Averages	4.8	12.3	4.1	- 9.7	9.3	10.0	8.0

Source

Standard and Poors Industry Surveys Utilities Electric, Section 3, March 30, 1978.

Federal Power Commission Statistics of Privately Owned Electric Utilities in the United States, 1971, 1972, 1974 and 1975.

Statistics of Privately Owned Electric Utilities in the United States, (Washington, D.C.: U.S. Department of Energy, 1976).

TABLE 5

PERCENT CHANGE IN DIVIDENDS

ELECTRIC UTILITIES	70-71	71-72	72-73	73-74	74-75	75-76	76-77
Arizona Public Service Co.	0.0	3.7	8.0	12.4	0.0	2.2	20.9
Baltimore Gas & Electric Co.	- 3.5	- 3.6	- 1.6	-33.8	0.0	4.6	5.4
Boston Edison Co.	5.9	3.9	0.8	0.0	0.0	0.0	0.0
Cincinnati Gas & Electric Co.	4.0	15.2	- 4.3	0.0	0.0	0.0	12.2
Cleveland Electric Illuminating Co.	- 1.9	5.4	- 5.6	11.1	3.1	3.6	7.6
Commonwealth Edison Co.	0.0	0.0	3.4	1.1	0.0	3.3	1.1
Consolidated Edison of New York, Inc.	0.0	0.0	0.0	-52.7	41.0	33.3	37.5
Consumer Power Co.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dayton Power & Light Co.	2.8	0.9	0.0	0.0	0.0	0.0	0.0
Detroit Edison Co.	0.0	0.0	2.7	0.9	0.0	0.0	4.8
Duquesne Light Co.	0.0	0.0	2.7	0.9	0.0	0.0	0.0
Florida Power & Light Co.	4.4	3.8	5.5	14.2	8.3	8.7	12.8
Florida Power Co.	3.7	3.6	3.4	8.3	1.9	7.9	15.6
Illinois Power Co.	7.3	0.0	0.0	0.0	0.0	0.0	3.6
Indianapolis Power & Light Co.	0.0	4.0	7.1	9.0	0.0	0.0	9.9
Long Island Light Co.	3.0	2.9	2.1	6.6	2.1	3.7	5.5
New York State Electric & Gas Corp.	0.0	1.0	3.3	1.4	0.0	9.0	5.0
Niagara Mohawk Power Corp.	0.0	1.8	2.7	2.6	2.4	2.5	8.1
Northern States Power (Minn.)	3.0	2.0	5.9	0.0	1.4	4.2	6.1
Ohio Edison Co.	0.0	0.0	2.9	5.0	0.9	0.6	5.9
Oklahoma Gas & Electric Co.	6.9	3.2	3.1	3.0	2.9	2.9	6.9
Pacific Gas & Electric Co.	7.0	5.9	3.8	5.1	1.3	0.0	14.9
Philadelphia Electric Co.	0.0	0.0	0.0	0.0	0.0	0.0	9.8
Public Service Company of Colorado	2.8	1.8	3.5	1.7	0.0	11.7	9.0
Public Service Electric & Gas Co.	0.0	3.7	1.2	0.0	0.0	3.5	10.1
South Carolina Electric & Gas Co.	5.6	3.8	3.7	3.6	0.9	2.0	7.3
Southern California Edison Co.	1.7	4.0	0.0	5.8	1.8	0.0	33.3
Tampa Electric Co.	- 1.3	3.8	3.5	72.1	31.8	- 2.6	-36.8
Union Electric Co.	- 1.7	0.0	0.0	0.0	0.0	4.7	1.5
Virginia Electric & Power Co.	0.0	0.0	4.0	1.3	0.0	3.8	1.2
Wisconsin Electric Power Co.	4.2	5.9	7.9	9.0	5.0	4.2	5.6
Averages	1.9	2.5	2.2	2.7	3.4	3.7	7.2
ELECTRIC UTILITY HOLDING COMPANIES							
Allegheny Power System, Inc.	3.0	2.9	2.9	5.6	1.3	5.2	6.1
American Electric Power Co.	2.7	3.8	4.8	6.8	1.3	0.8	5.2
Central & Southwestern Corp.	5.2	4.0	3.7	3.7	3.6	3.4	11.7
General Public Utility Corp.	0.0	0.0	0.0	- 6.3	0.0	0.0	4.8
Houston Industries	7.5	5.4	2.9	7.1	4.0	3.2	31.7
Middle Southern Utilities, Inc.	6.3	3.9	6.1	8.0	3.7	4.8	9.1
New England Electric System	5.4	1.9	7.2	4.4	0.0	3.4	5.4
Southern Co.	- 3.2	3.2	3.1	4.1	0.4	1.1	8.8
Texas Utilities Co.	5.9	5.0	4.0	5.8	11.9	6.6	16.9
Averages	3.6	3.3	3.9	4.4	2.9	3.2	11.1

Source

Standard and Poors Industry Surveys Utilities Electric, Section 3, March 30, 1978.

Federal Power Commission Statistics of Privately Owned Electric Utilities in the United States, 1971, 1972, 1974 and 1975.

Statistics of Privately Owned Electric Utilities in the United States (Washington, D.C.: Department of Energy, 1976).

TABLE 6

AVERAGE PRICE-EARNINGS RATIO (HIGH + LOW DIVIDED BY 2)

ELECTRIC UTILITIES	1970	1971	1972	1973	1974	1975	1976	1977
Arizona Public Service Co.	12.0	12.0	9.5	7.5	6.5	5.5	7.0	6.9
Baltimore Gas & Electric Co.	10.5	11.0	11.0	9.0	6.5	7.0	8.0	8.9
Boston Edison Co.	10.5	11.0	10.0	11.0	8.0	8.0	9.0	11.7
Cincinnati Gas & Electric Co.	11.5	12.5	10.0	9.5	9.5	9.0	11.0	7.9
Cleveland Electric Illuminating Co.	11.0	12.5	11.0	16.5	7.5	8.0	8.5	7.3
Commonwealth Edison Co.	12.0	13.5	11.5	10.5	9.0	10.0	9.0	9.5
Consolidated Edison of New York,Inc.	11.0	11.0	12.5	9.5	5.0	3.0	4.5	5.1
Consumer Power Co.	11.0	12.5	11.0	11.0	13.0	5.5	5.5	7.3
Dayton Power & Light Co.	11.0	12.0	11.0	11.0	8.5	6.5	9.0	10.4
Detroit Edison Co.	11.0	12.0	10.0	10.5	8.5	8.0	8.5	8.1
Duquesne Light Co.	10.5	11.0	10.0	9.0	7.0	6.5	10.0	10.1
Florida Power & Light Co.	15.5	15.5	12.5	15.5	8.5	5.0	6.5	6.3
Florida Power Co.	16.5	13.0	13.0	10.5	8.0	6.5	10.5	6.7
Illinois Power Co.	12.0	15.5	14.0	11.5	9.0	8.0	10.5	9.5
Indianapolis Power & Light Co.	12.0	11.5	9.5	9.5	10.0	7.5	9.0	6.6
Long Island Light Co.	12.5	11.5	10.5	10.0	7.0	5.5	6.5	7.2
New York State Electric & Gas Corp.	10.5	13.0	10.0	9.5	6.0	6.5	8.0	8.5
Niagara Mohawk Power Corp.	10.5	11.0	9.0	11.0	6.5	5.0	8.5	8.5
Northern States Power (Minn.)	10.0	11.0	10.0	10.5	8.5	7.0	9.0	8.2
Ohio Edison Co.	12.5	15.0	12.0	9.5	9.5	7.5	9.0	9.3
Oklahoma Gas & Electric Co.	13.0	15.5	9.0	12.5	10.5	11.0	11.0	8.9
Pacific Gas & Electric Co.	11.5	11.5	10.0	8.5	6.5	8.0	7.5	7.7
Philadelphia Electric Co.	12.0	11.0	11.5	10.5	8.0	7.0	8.5	10.0
Public Service Company of Colorado	11.5	13.0	10.5	9.0	8.5	7.0	8.5	10.8
Public Service Electric & Gas Co.	9.5	9.0	11.0	9.5	6.5	6.5	7.0	7.9
South Carolina Electric & Gas Co.	12.5	15.5	11.5	11.5	9.0	6.5	9.0	8.2
Southern California Edison Co.	10.5	12.0	10.5	8.5	4.5	6.0	5.5	6.8
Tampa Electric Co.	15.5	24.5	12.5	10.5	9.0	7.0	9.0	8.7
Union Electric Co.	10.0	12.5	13.5	9.5	9.0	6.5	8.0	8.6
Virginia Electric & Power Co.	12.0	12.0	10.0	8.5	7.0	5.5	8.0	7.4
Wisconsin Electric Power Co.	10.5	12.0	9.0	8.0	8.0	10.5	9.0	8.2
Averages	11.7	12.8	10.8	10.3	8.0	7.0	8.6	8.3
ELECTRIC UTILITY HOLDING COMPANIES								
Allegheny Power System, Inc.	9.5	10.5	10.0	9.0	9.0	6.0	7.5	7.9
American Electric Power Co.	12.0	12.0	11.0	9.0	10.0	7.5	9.0	9.6
Central & Southwestern Corp.	14.5	15.5	14.0	11.5	8.0	9.0	9.0	7.9
General Public Utility Corp.	11.5	11.0	10.0	9.0	6.5	7.0	8.0	8.0
Houston Industries	15.5	16.5	16.0	12.5	8.0	7.5	6.5	6.8
Middle Southern Utilities, Inc.	14.5	15.0	12.5	10.0	6.0	8.5	8.5	7.4
New England Electric System	11.5	11.0	10.0	9.5	7.5	6.5	8.5	7.8
Southern Co.	12.5	13.0	11.0	8.5	9.0	5.5	9.0	8.5
Texas Utilities Co.	16.5	17.5	15.5	13.5	9.0	10.5	8.5	8.2
Averages	13.1	13.6	12.2	10.3	8.1	7.6	8.3	8.0

Source

Standard and Poors Industry Surveys Utilities Electric, Section 3, March 30, 1978.

Federal Power Commission Statistics of Privately Owned Electric Utilities in the United States, 1971, 1972, 1974 and 1975.

Statistics of Privately Owned Electric Utilities in the United States, (Washington, D.C.: Department of Energy, 1976)

TABLE 7

PERCENT RATE OF RETURN ON COMMON STOCK EQUITY

ELECTRIC UTILITIES	1970	1971	1972	1973	1974	1975	1976
Arizona Public Service Co.	10.1	10.0	11.4	11.8	10.9	13.5	11.2
Baltimore Gas & Electric Co.	12.2	12.0	11.7	11.7	11.1	10.5	11.7
Boston Edison Co.	11.6	12.0	12.4	8.8	8.2	7.5	7.2
Cincinnati Gas & Electric Co.	15.8	13.7	15.1	13.9	10.7	10.8	10.3
Cleveland Electric Illuminating Co.	14.5	14.2	14.4	13.1	15.0	13.1	13.8
Commonwealth Edison Co.	13.0	12.1	13.3	12.0	10.6	11.0	11.6
Consolidated Edison of New York, Inc.	7.4	11.1	6.6	9.0	7.7	10.0	11.6
Consumers Power Co.	11.6	10.2	9.9	8.7	8.0	8.8	12.1
Dayton Power & Light Co.	12.5	12.0	11.7	10.1	10.1	12.4	11.6
Detroit Edison Co.	9.9	9.5	10.4	9.4	7.5	7.5	7.9
Duquesne Light Co.	13.7	13.4	12.4	11.0	10.9	10.8	8.4
Florida Power & Light Co.	11.9	14.1	13.5	13.3	11.1	13.4	9.0
Florida Power Co.	15.0	13.7	13.8	12.2	8.4	13.4	10.5
Illinois Power Co.	17.2	13.2	12.1	12.7	11.3	13.2	11.2
Indianapolis Power & Light Co.	13.9	14.1	17.1	14.3	9.9	13.4	13.7
Long Island Light Co.	12.5	12.8	12.8	11.2	11.2	13.4	14.2
New York State Electric & Gas Corp.	10.4	9.2	10.7	10.7	11.1	10.9	11.4
Niagara Mohawk Power Corp.	9.4	9.6	11.1	8.2	11.6	12.2	9.7
Northern States Power (Minn.)	12.6	13.4	13.5	12.2	10.6	13.0	12.6
Ohio Edison Co.	14.2	13.6	14.7	14.9	11.9	13.0	14.0
Oklahoma Gas & Electric Co.	17.4	15.8	15.4	14.9	13.5	12.8	12.0
Pacific Gas & Electric Co.	10.6	11.4	11.8	12.2	11.4	9.7	10.2
Philadelphia Electric Co.	9.5	10.8	10.3	6.8	8.9	9.4	9.8
Public Service Co. of Colorado	12.6	12.0	12.7	12.8	9.4	12.6	11.0
Public Service Electric & Gas Co.	10.7	12.5	10.0	10.5	12.9	9.0	11.2
South Carolina Electric & Gas Co.	14.1	11.0	11.4	10.0	8.6	12.7	12.2
Southern California Edison Co.	11.2	9.7	9.5	9.6	13.6	10.0	11.2
Tampa Electric Co.	14.5	9.4	14.2	13.4	11.1	13.7	12.8
Union Electric Co.	13.4	10.8	9.0	10.6	8.4	11.5	12.2
Virginia Electric & Power Co.	12.3	11.1	11.7	11.4	9.7	10.5	9.7
Wisconsin Electric Power Co.	8.2	8.3	11.9	12.6	10.2	10.0	11.6
Averages	12.4	11.8	12.1	11.4	10.5	11.4	11.2

Source

Standard and Poors Industry Surveys Utilities Electric, Section 3, March 30, 1978.

Federal Power Commission Statistics of Privately Owned Electric Utilities in the United States, 1971, 1972, 1974 and 1975.

Statistics of Privately Owned Electric Utilities in the United States, (Washington, D.C.: Department of Energy, 1976).

TABLE 8

PERCENT CHANGE IN RATE OF RETURN ON COMMON STOCK

ELECTRIC UTILITIES	70-71	71-72	72-73	73-74	74-75	75-76
Arizona Public Service Co.	- .9	14.0	3.5	- 7.6	23.9	-20.5
Baltimore Gas & Electric Co.	- 1.6	- 2.5	- 2.5	- 5.1	- 5.4	11.4
Boston Edison Co.	3.4	3.3	-29.0	- 6.8	- 8.5	- 4.0
Cincinnati Gas & Electric Co.	-13.3	10.2	- 7.9	-23.0	.9	- 4.6
Cleveland Electric Illuminating Co.	- 2.1	1.4	- 9.0	14.5	-19.3	5.3
Commonwealth Edison Co.	- 6.9	9.9	- 9.8	-11.7	3.8	5.5
Consolidated Edison of New York, Inc.	50.0	-40.5	36.4	-14.4	29.9	16.0
Consumers Power Co.	-12.1	- 2.9	-12.0	- 8.0	10.0	37.5
Dayton Power & Light Co.	- 4.0	- 2.5	-13.7	0.0	22.8	- 6.5
Detroit Edison Co.	- 4.0	9.5	- 9.6	-20.2	0.0	5.3
Duquesne Light Co.	- 2.2	- 7.5	-11.3	- .9	- .9	-22.2
Florida Power & Light Co.	18.5	- 4.3	- 1.4	-16.5	20.7	-32.8
Florida Power Co.	- 8.7	.7	-11.6	-31.1	59.5	-21.6
Illinois Power Co.	-23.3	- 8.3	5.0	-11.0	16.8	-15.2
Indianapolis Power & Light Co.	1.4	21.3	-16.4	-30.8	25.3	10.5
Long Island Light Co.	2.4	0.0	-12.5	0.0	19.6	6.0
New York State Electric & Gas Corp.	-11.5	16.3	0.0	3.7	- 1.8	4.6
Niagara Mohawk Power Corp.	2.1	15.6	-26.1	41.5	5.2	-20.5
Northern States Power (Minn.)	6.3	.7	- 9.6	-13.1	22.6	- 3.1
Ohio Edison Co.	9.9	8.1	1.4	-20.1	.9	7.7
Oklahoma Gas & Electric Co.	- 9.2	- 2.5	- 3.2	- 9.4	- 5.2	- 6.3
Pacific Gas & Electric Co.	7.5	3.5	3.4	- 6.6	-14.9	5.2
Philadelphia Electric Co.	13.7	- 4.6	-34.0	30.9	5.6	4.3
Public Service Co. of Colorado	- 4.8	5.8	.8	-26.6	34.0	-12.7
Public Service Electric & Gas Co.	16.8	-20.0	5.0	22.9	-30.2	24.4
South Carolina Electric & Gas Co.	-22.0	3.6	-12.3	14.0	47.7	- 3.9
Southern California Edison Co.	-13.4	- 2.1	1.1	41.7	-26.5	12.0
Tampa Electric Co.	-35.2	51.0	- 5.6	-17.2	23.4	- 6.6
Union Electric Co.	-19.4	-16.7	17.8	-20.8	36.9	6.1
Virginia Electric & Power Co.	- 9.8	5.4	- 2.6	-14.9	8.2	- 7.6
Wisconsin Electric Power Co.	1.2	43.4	5.9	-19.0	- 2.0	16.0
Averages	- 2.3	3.5	- 5.2	- 5.3	10.0	- .3

Source

Standard and Poors Industry Surveys Utilities Electric, Section 3, March 30, 1978.

Federal Power Commission Statistics of Privately Owned Electric Utilities in the United States, 1971, 1972, 1974 and 1975.

Statistics of Privately Owned Electric Utilities in the United States, (Washington, D.C.: U.S. Department of Energy, 1976).

TABLE 9

PERCENT RATE OF RETURN ON RATE BASE

ELECTRIC UTILITIES	1970	1971	1972	1973	1974	1975	1976
Arizona Public Service Co.	6.8	6.7	7.4	7.8	7.8	6.9	9.3
Baltimore Gas & Electric Co.	8.2	8.4	8.3	8.7	8.9	10.2	9.4
Boston Edison Co.	7.0	7.1	5.4	7.5	8.2	7.8	7.7
Cincinnati Gas & Electric Co.	8.9	8.7	9.0	8.9	7.5	8.4	7.7
Cleveland Electric Illuminating Co.	9.4	9.2	9.0	8.6	9.9	9.5	10.0
Commonwealth Edison Co.	7.0	7.0	7.1	7.1	6.7	7.0	7.8
Consolidated Edison of New York, Inc.	5.8	6.1	6.0	6.8	7.4	8.5	8.5
Consumers Power Co.	6.6	5.9	6.0	5.6	4.3	7.5	9.0
Dayton Power & Light Co.	8.6	8.1	7.8	7.6	7.8	9.0	8.2
Detroit Edison Co.	6.5	6.9	7.5	7.4	6.5	7.2	7.7
Duquesne Light Co.	7.5	7.7	7.8	8.0	8.4	8.6	7.4
Florida Power & Light Co.	8.7	8.6	7.7	8.4	7.7	9.7	7.3
Florida Power Co.	8.1	8.1	8.6	7.6	6.4	9.0	9.0
Illinois Power Co.	8.7	7.6	7.3	8.0	7.3	8.2	7.5
Indianapolis Power & Light Co.	7.9	8.1	9.7	8.8	7.2	8.0	8.5
Long Island Light Co.	7.4	7.7	7.4	7.4	7.8	9.7	10.3
New York State Electric & Gas Corp.	6.7	6.8	6.9	6.3	7.4	8.2	DNA
Niagara Mohawk Power Corp.	5.5	6.1	6.3	7.5	7.7	8.8	7.4
Northern States Power (Minn.)	8.0	8.1	8.2	7.1	7.1	7.9	8.5
Ohio Edison Co.	7.9	7.6	8.2	8.9	7.6	9.0	7.6
Oklahoma Gas & Electric Co.	9.0	8.5	8.8	8.9	8.8	8.8	8.4
Pacific Gas & Electric Co.	6.5	7.2	7.3	7.6	7.7	6.6	7.1
Philadelphia Electric Co.	7.0	7.6	8.0	7.8	6.6	7.6	DNA
Public Service Company of Colorado	7.0	7.0	7.6	7.5	7.2	7.8	8.2
Public Service Electric & Gas Co.	6.8	8.0	7.1	7.3	7.9	8.5	9.3
South Carolina Electric & Gas Co.	7.2	6.9	7.9	7.0	7.0	8.4	8.7
Southern California Edison Co.	7.3	6.6	7.0	7.2	8.7	7.3	7.7
Tampa Electric Co.	7.6	6.4	8.2	8.0	6.4	7.9	7.0
Union Electric Co.	8.0	7.2	6.5	7.6	7.1	8.3	9.2
Virginia Electric & Power Co.	7.2	7.3	7.3	8.0	7.3	9.1	8.9
Wisconsin Electric Power Co.	6.8	6.5	7.6	8.0	7.1	7.6	8.7
Averages	7.5	7.4	7.6	7.7	7.5	8.3	8.3

DNA - Data not available.

Source

Standard and Poors Industry Surveys Utilities Electric, Section 3, March 30, 1978.

Federal Power Commission Statistics of Privately Owned Electric Utilities in the United States, (Washington, D.C.: U.S. Department of Energy, 1976).

TABLE 10

PERCENT CHANGE IN RATE OF RETURN ON RATE BASE

ELECTRIC UTILITIES	70-71	71-72	72-73	73-74	74-75	75-76
Arizona Public Service Co.	- 1.5	10.4	5.4	0.0	-11.5	34.8
Baltimore Gas & Electric Co.	2.4	- 1.2	4.8	2.3	14.6	- 7.8
Boston Edison Co.	1.4	-23.9	38.9	9.3	- 4.9	- 1.3
Cincinnati Gas & Electric Co.	- 2.2	- 2.2	- 1.1	-15.7	12.0	- 8.3
Cleveland Electric Illuminating Co.	- 2.1	- 2.1	- 4.4	15.1	- 4.0	5.3
Commonwealth Edison Co.	0.0	1.4	0.0	- 5.6	4.5	11.4
Consolidated Edison of New York, Inc.	5.2	- 1.6	13.3	8.8	14.9	0.0
Consumers Power Co.	-10.6	1.7	- 6.7	-23.2	74.4	20.0
Dayton Power & Light Co.	- 5.8	3.7	- 2.6	2.6	15.4	- 8.9
Detroit Edison Co.	6.1	8.7	- 1.3	-12.2	10.8	6.9
Duquesne Light Co.	2.7	1.3	2.6	5.0	2.4	-14.0
Florida Power & Light Co.	- 1.1	-10.5	9.1	- 8.3	26.0	-14.4
Florida Power Co.	0.0	6.2	-11.6	-15.8	40.6	0.0
Illinois Power Co.	-12.6	- 3.9	9.6	- 8.4	12.3	- 8.5
Indianapolis Power & Light Co.	2.5	19.8	- 9.3	-18.2	11.1	6.3
Long Island Light Co.	4.1	- 3.9	0.0	5.4	24.4	6.2
New York State Electric & Gas Corp.	1.5	1.5	- 8.7	17.5	10.8	DNA
Niagara Mohawk Power Corp.	10.9	3.3	19.0	2.7	14.3	-15.9
Northern States Power (Minn.)	1.3	1.2	-13.4	0.0	11.3	7.6
Ohio Edison Co.	- 3.8	7.9	8.5	-14.6	18.4	-15.6
Oklahoma Gas & Electric Co.	- 5.6	3.5	1.1	- 1.1	0.0	- 4.5
Pacific Gas & Electric Co.	-10.8	1.4	4.1	1.3	-14.3	7.6
Philadelphia Electric Co.	8.6	5.3	- 2.5	-15.4	15.2	DNA
Public Service Company of Colorado	0.0	8.6	- 1.3	- 4.0	8.3	5.1
Public Service Electric & Gas Co.	17.6	-11.3	2.8	8.2	7.6	9.4
South Carolina Electric & Gas Co.	- 4.2	14.5	-11.4	0.0	20.0	3.6
Southern California Edison Co.	- 9.6	6.1	2.9	20.8	-16.1	5.5
Tampa Electric Co.	-15.8	28.1	- 2.4	-20.0	23.4	-11.4
Union Electric Co.	-10.0	- 9.7	16.9	- 6.6	16.9	10.8
Virginia Electric & Power Co.	1.4	0.0	9.6	- 8.8	24.7	- 2.2
Wisconsin Electric Power Co.	- 4.4	16.9	5.3	7.0	7.0	14.5
Averages	- 1.1	2.8	2.5	- 2.3	12.6	1.4

DNA - Data Not Available

Source

Standard and Poors Industry Surveys Utilities Electric, Section 3, March 30, 1978.

Federal Power Commission Statistics of Privately Owned Electric Utilities in the United States, (Washington, D.C.: U.S. Department of Energy, 1976).

recovered substantially for most electric utility companies boosting the average from .62 in 1974 to .90 in 1977. In 1978 the ratio had dropped again for most companies lowering the average to .79. The electric utility holding companies' ratio of market to book value of common stock followed a similar if somewhat lagged pattern over the nine-year period.

From this information one might conclude that the electric utilities were in general more attractive investments in 1970 and 1971 than they were in 1973 or 1974. They were again relatively attractive in 1976 and 1977 but not as much so as the early 1970's. However, in 1978 they appeared to be losing ground again.

The obvious danger in this comparison is that how the entire market was performing over this period is not included. This would be of great consequence in judging whether the firm would want to use the common stock option at all as it sought to obtain capital. Another danger might lie within the ratio itself. It is generally believed that the market value is very sensitive to a discounted stream of earnings perceived by the investor. This would make the market value dependent on the income statement which measures flows in the accounts of the firm. The book value is obtained from the balance sheet (assets--liabilities--preferred stock) divided by the number of shares of common stock, which shows the levels of the accounts at a specific point in time. Making a ratio of the two items would make for problems in inferential analysis.

In Table 4 the percentage change in earnings per share shows a somewhat similar financial picture for the forty firms. The typical firm increased earnings per share between 1970-1971 and again in 1972. Between 1972 and 1973 earnings per share began to decrease slightly for the typical electric utility and again decreased more dramatically in the following two years. However, by 1976 earnings per share had recovered substantially and continued to do so through 1977. Although the range of data was much larger in each column in the percentage change in earnings per share, it followed roughly the same pattern as the ratio of market to book value for the common stocks. The firms generally had increased earnings per share up to 1972 and then began to decrease reaching a minimum in 1974 and then increased through 1977. As might be expected, the earnings per share data will vary much more between the companies and will be more erratic for each firm over time than would the ratio of market value to book value.

In Table 5 the percentage change in dividends over the same eight year period shows a somewhat different story. The general trend for the firms was to increase dividend payout throughout the period. However, two things should be noticed about these increases. First, the fact that most firms increased their dividend payout between 1973 and 1974 at a time when earnings were generally depressed, could demonstrate these firms needed to attract equity capital and were trying to boost the market value of their common stock. Another item of notice is the large increase in dividend payout between 1976 and 1977 which shows a more healthy financial picture in this period.

An easily available measure of the attractiveness of common stocks widely used by individual investors is the price-earnings ratio. Table 6 shows the average price-earnings (P-E) ratio for each year from 1970 to 1977. This was computed by adding the high and low value for the year and dividing by 2. This is obviously a very rough estimate of the value at any given point within the year but it shows a general trend in the P-E ratio over the eight-year period. The early seventies saw a relatively high P-E ratio as compared with the four years following 1973. However, between 1971 and 1975 we still see a downward trend in the P-E ratio. This shows a pattern somewhat similar to the percentage change in earnings per share and the ratio of market to book value of the common stock. In this case, however, the minimum average price earnings ratio occurs in 1975 rather than 1974. This is probably because of the earnings recovery in the 1974-1975 period not being fully reflected yet in the market price of the stock. Another difference is that the P-E ratio did not increase in 1977. This could be due to the coincidental movement of the market price of the common stock and earnings. The fact that the P-E ratio lost ground slightly could reflect some stockholder uncertainty about the future of the industry.

One of the most comprehensive measures of financial strength of a firm is the rate of return on common stock equity. Generally speaking this reflects the net profit margin, the asset turnover, and the financial leverage multiplier in the following formula:

$$\underset{\substack{\text{PROFIT}\\ \text{MARGIN}}}{\frac{NPAT}{S}} \times \underset{\substack{\text{ASSET}\\ \text{TURNOVER}}}{\frac{S}{TA}} \times \underset{\substack{\text{FINANCIAL}\\ \text{LEVERAGE}\\ \text{MULTIPLIER}}}{\frac{TA}{CSE}} = \underset{\substack{\text{RATE OF RETURN ON}\\ \text{COMMON STOCK EQUITY}}}{\frac{NPAT}{CSE}}$$

where NPAT - net profit after taxes

S - sales

TA - total assets

CSE - common stock equity (I have assumed common stock equity = net worth for the financial leverage multiplier)

This data for the thirty-one electric utilities (but not for the nine holding companies) for 1970 through 1976 is shown in Table 7. The general trend (with the exception of 1972) was a decline between the years from 1970 to 1974 with the largest drop between 1973-1974 on average. The rate of return on common stock equity recovered substantially by 1975 and for all practical purposes remained the same on average for the industry in 1976.

This again shows that throughout this seven year period most firms lost ground and were in their poorest financial condition by 1974. After 1974 the financial strength of most firms improved and remained somewhat stable after 1975 with smaller increases or decreases for most firms.

A measure of financial condition which is peculiar to the regulated sector of the economy is the rate of return on rate base. Used here is the Federal Power Commission's definition of the rate base, although what to include or not include in the rate base is still hotly debated. Data are for a seven-year period for the thirty-one electric utility holding companies.

Although the rate itself fluctuates only slightly up to 1975 when it generally increases, the average percentage change between the years reveals a more telling story. Here a general increase in percentage change in the rate of return occurs between the years up to 1973 when there was a decrease for many firms. Between 1974 and 1975 there was a large percentage change in the rate followed by a much smaller one between 1975 and 1976. The rate of return on rate base reflects more accurately how rate relief granted to utilities was affecting all the previous representatives of the financial condition of the firms. The large increase in the rate of return on rate base between 1974-1975 may have offset the decrease in the rate of return on rate base in 1973-1974 for most firms.

Throughout this brief report the focus has been on general trends in the financial position of these thirty-one electric utilities and nine holding companies. Aside from the relatively strong financial position of the southwest holding companies at the outset, this has somewhat accurately reflected average firm movements in the time periods studied. This appraisal has been limited almost completely to earnings and common stock prices to show the relative attractiveness of common stocks and thus the firms' ability to attract equity capital. Aside from some solvency problems, this also gives a general idea of their ability to attract debt capital on favorable terms. Both of these assumptions may lead to some danger insofar as interpretations of the data as related to a specific historical event are concerned. No cross industry or general market comparisons have been attempted in this report. This makes for a tentative and limited comment on the relative attractiveness of these electric utility companies throughout the specified time period.

With these reservations in mind, a very brief attempt to summarize and relate the data from the Arab Oil Embargo in the 1973-1974 time period and its effect on the ability of the firms to attract capital follows.

As we have seen, in most instances the financial conditions of the electric utilities on average were deteriorating slightly from 1970 to 1973. Between 1973 and 1974 most of the utilities experienced a serious decline in their financial condition. This coincided with not only the oil embargo but also with general increases in consumer demand in this period. This caused the utilities to embark on large expansion programs at a time when their relative attractiveness to an investor was lower. Since firms are naturally hesitant to obtain capital on unfavorable terms, the utilities were in a serious position. Therefore, at least some of the 1974 to 1976 rate increases were needed not only to improve the financial condition of the firms but also to stem the tide of rising consumer demand for electric power. After the 1976 rate increases, continued use of company financial plight as a reason for increased rates may not be as valid as it was in the earlier time period. However, if a major downturn in the national economy and in the financial condition of the utility sector occurs in 1979-1980, this may again become an entirely legitimate basis for further fiscal relief.

B. Price Productivity Relationships*

Historically, U.S. industries in which productivity has lagged behind the overall, or national productivity trend have usually been those in which prices rose relative to the general level of prices. Economic theory suggests that when an industry's prices decline relative to the general price level, productivity increases may be partly responsible.[15] More efficient production methods may lead to lower unit costs and result in a more favorable relative price position. When an industry's products become relatively cheaper, its sales volume is likely to expand bringing additional investment and employment opportunities into that industry; this, in turn, may lead to even greater productivity increases.

This relationship between productivity and prices is not absolute. There are many determinants of an industry's relative selling price besides productivity. These factors, among others, would include input prices which are in part determined by the productivity levels in the input industries. Furthermore, an absence of competition may also affect the price-productivity relationship. As a group, factors affecting prices other than productivity are just as important as productivity. These factors generally exert a greater influence on prices over shorter (as opposed to longer) periods of time.

Inflation introduces an uncertain element into the cause-effect relationship of prices and productivity. It has been pointed out that an industry's relative price is, in part, a function of the industry's productivity rate. Inflation disrupts this functional form, making it very difficult to ascertain productivity's contribution to holding down prices.

Edward Renshaw points out that from the perspective of basic dimensions

*This section was prepared by Mr. Curtis Odle, Economist and Graduate Research Associate, National Regulatory Research Institute staff.

of economic and technological progress such as speed, scale, new products, natural resource scarcity, and the efficiency of converting energy into useful effects, it is strongly suggested that it is becoming more difficult to invent new productive processes that are unambiguously superior to existing products and production techniques.[16]

It is becoming more difficult than ever to induce the rapidly rising industry productivity rates that were recognized in the first half of this century. This phenomena, coupled with the inflationary climate of the last decade and a half, suggests that the price-productivity relationship is changing. Prices are more rigid today and less willing to decline in response to greater production efficiency. At today's double digit rate of inflation, productivity increases have little chance of mitigating price increases to a noticeable extent.

Table 11 summarizes Renshaw's comparison of (1) output per man-hour (for all persons); and (2) labor productivity in the gas and electric utility industry for three historical time periods.[17] Renshaw concludes that it does not seem plausible to expect longer run rates of productivity in the gas and electric industries to recover to the extraordinary levels of 1947-1966.

TABLE 11

AVERAGE ANNUAL GROWTH RATES IN PRODUCTIVITY FOR ALL PERSONS AND LABOR PRODUCTIVITY IN THE GAS AND ELECTRIC INDUSTRY.

	1947-1953	1953-1966	1966-1973
All Persons	4.1%	3.0%	2.1%
Gas and Electric	7.2%	7.0%	4.8%

Source: Edward F. Renshaw, "Productivity and the Demand for Electricity," Public Utilities Fortnightly, (May 6, 1976), p. 17.

For the economy as a whole, output per man hour in the U.S. dropped 2.7% in 1974, the first decline since 1947.[18] Also in 1974 the consumer price index increased 10.9% over the 1973 index, which marked the beginning of double digit price increases. The movement of prices and productivity over the 20-year period prior to 1974 suggests that the maintenance of U.S. economic health may in part be achieved by productivity growth surpassing the growth of general price levels. The downturn of productivity in 1974, therefore, may be interpreted as a violent disruption to the historical trend.

By juxtaposing the consumer price index for all items (CPI) with the consumer price index for gas and electricity (GEPI), definite changes in the growth rates of both indexes were identified in 1967 and 1974 (see Figure 1). For the period 1955-1967, the general price index grew at an average annual rate of 1.9%. For the period 1968-1973, average annual growth rates for the CPI and GEPI were 4.9% and 4.0% respectively. In years 1974 and 1975, the effects of the oil embargo contributed to even sharper increases, especially in the GEPI. The 1974 GEPI increased 15.35% over 1973 levels, while in 1975 the same index climbed 16.32% over the 1974 index. These growth rates are summarized in Table 12.

Figure 1 shows the trend of output per man-hour for the production worker in the gas and electric industry. This index has been growing at a fairly brisk pace of 5.8% per year on average, while the output per man-hour for all employees in the gas and electric industry has grown at an average annual rate of 5.3% (see Figure 2). It is evident that for the period 1955-1972 productivity as measured by these indexes has grown at a faster

FIGURE 1

Consumer Price Index, Gas and Electric Price Index and
Production Worker (Gas and Electric) Output per Man-Hour

[1967=100]

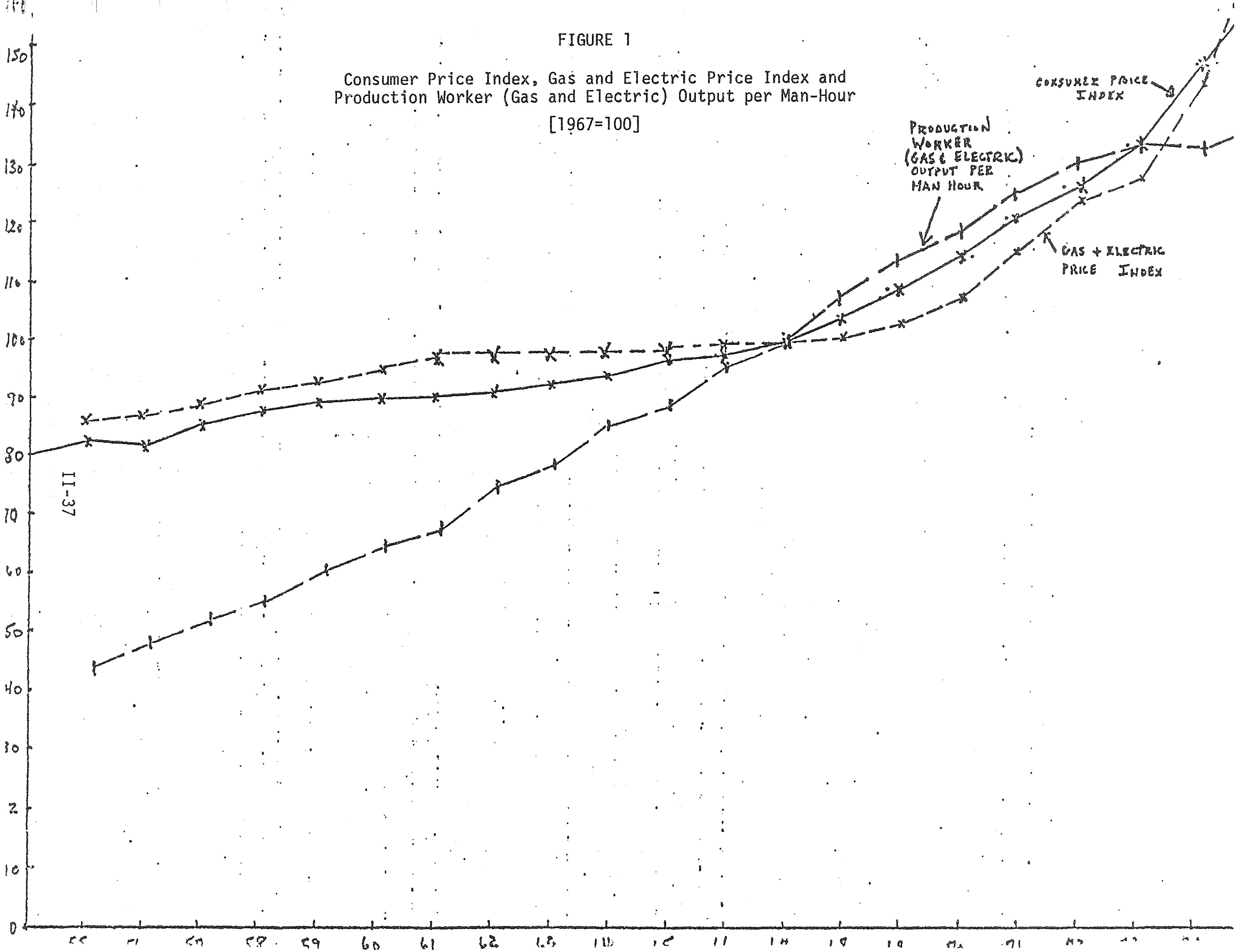
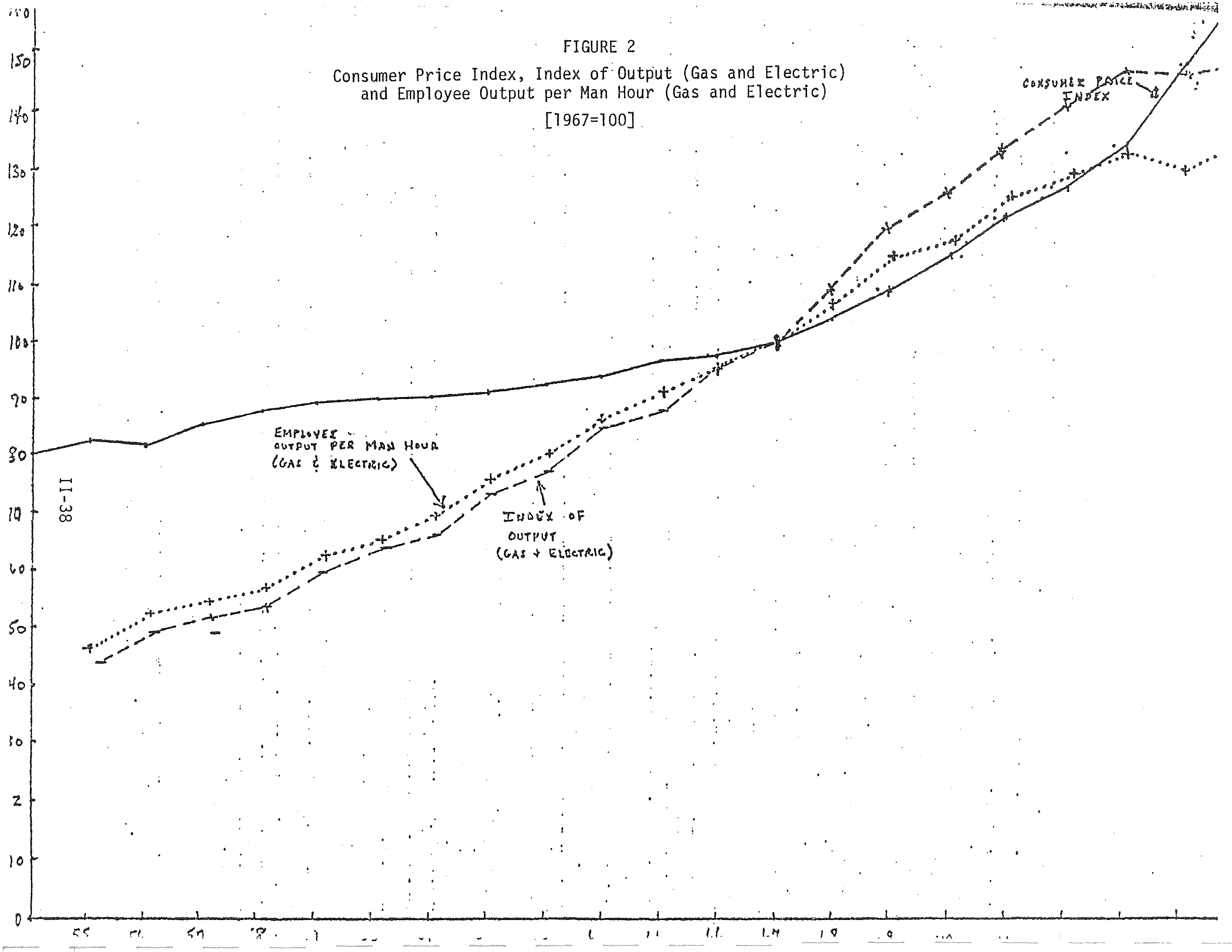


FIGURE 2

Consumer Price Index, Index of Output (Gas and Electric) and Employee Output per Man Hour (Gas and Electric)

[1967=100]



rate each year than the CPI with the exception of 1969 and output per man-hour increased at a faster rate each year than the GEPI until 1970 which marked the beginning of a reverse trend.

Table 12 also summarizes average annual growth rates in labor productivity for the gas and electric industry for the four defined time periods.

TABLE 12

AVERAGE ANNUAL GROWTH RATES OF THE CONSUMER PRICE INDEX (CPI), THE GAS AND ELECTRIC PRICE INDEX (GEPI), EMPLOYEE OUTPUT PER MAN-HOUR IN THE GAS AND ELECTRIC INDUSTRY (EO), AND PRODUCTION WORKER OUTPUT PER MAN-HOUR IN THE GAS AND ELECTRIC INDUSTRY (PO) (1967 = 100).*

Index	1955-1967	1968-1973	1974	1975
CPI	1.9%	4.9%	10.9%	9.1%
GEPI	1.1%	4.0%	15.3%	16.3%
EO	6.5%	4.6%	-2.4%	2.6%
PO	6.9%	4.9%	-0.9%	3.3%

* Calculations were made based upon data obtained from U.S. Dept. of Labor, Bureau of Labor, Handbook of Labor Statistics, 1977.

After 1970 the gap between the GEPI and labor productivity in gas and electric industry began to close. In other words, advances in productivity levels together with other factors tending to push prices down were not able to overwhelm the inflationary price advances. How much productivity increases contributed to dampening price increases is difficult to discern. If price changes could be decomposed and a correct specification of the functional form explaining price changes could be identified, then productivity's contribution to holding down prices could be estimated. Kendrick suggests various methods for accomplishing this task and points out the many difficulties of estimating this relationship.[19]

Kendrick contends that productivity rates in the public utilities sector have generally been above average.[20] In part, this is due to the above average investment in new plant and equipment which has promoted production efficiency. Table 12 suggests that this growth in production efficiency may have favorably affected the gas and electric industry's relative price levels. Recent years, however, have witnessed a decline in capital input per kw.[21] This suggests that inflation has overtaken the benefits derived from productivity advances achieved through capital investments. The gas and electric industry is experiencing low rates of productivity in a severe inflationary climate. The implication is that to restore reasonable productivity advances, inflation must first be controlled.

IV. REGULATION IN A RETURN TO RELATIVE PRICE STABILITY

A. Wage and Price Guidelines

Soon after the announcement of the President's anti-inflation program, the Director of The National Regulatory Research Institute wrote to the Council on Wage and Price Stability to inquire as to the applicability of the Council's Voluntary Standards for Non-inflationary Pay and Price Behavior to the utility sector. Basically the reply was that no compelling reason could be found to treat that sector any differently and that power companies (and commissions) would be expected to comply.

Since that time(December 1978), various positions have been taken by companies and commissions on the issue. Some state regulators feel that fuel-cost adjustments in utility bills won't be held to the price guidelines;[23] others feel the guidelines must be addressed in rate proceedings with great visibility;[23] REA has told its co-op borrowers that it expects them to meet the wage-price guidelines and to report to the Rural

Electrification Administration how the guidelines were taken into account in fashioning rate hikes;[25] the standards are intended to apply to municipal and other publicly owned utilities as well as investor-owned utilities;[26] and some exemptions have emerged for purchased power costs, interest coverage, and certain cash flow problems.[27]

For its part, the National Association of Regulatory Utility Commissioners through its President pledged "total cooperation" with the program;[28] the New York Commission said it will expect utilities under its jurisdiction to abide by federal wage-price guidelines when requesting higher rates, as have the Colorado and the Iowa Commissions.[29]

In order to get some sense of the implications of the application of the guidelines to the electric and gas sectors, it is helpful to take a retrospective look at what would have been the circumstance if the present guidelines were applied in hindsight over the general rate requests of the utilities for 1977.

B. The Guidelines "Applied"*

President Carter's new anti-inflation program of October 24, 1978 has as its goal to reduce the nation's inflation rate to between 6% and 6.5% in 1979.[30] This new attack on the inflation rate called for an "economy-wide" ceiling of 5.75% for price increases.

The way in which such a program as introduced by governmental authorities actually impacts on various sectors of the economy is sometimes difficult to know ahead of time. A clear understanding of the manner in which guidelines such as those recently proposed by the President are best applied to particular sectors is necessary before a conscious contribution to governmental objectives can be made. This

*This section was prepared by Mr. Curtis Odle, Economist and Graduate Research Associate, NRRI staff.

is particularly true of the regulated sector, e.g., transportation, telecommunications, and power. Regulators and gas and electric utility executives alike, must be aware of the intended application of the President's proposed guidelines to rate adjustments. A proper concern of these parties was exactly how the President's guidelines apply to proposed utility rate increases. This was substantially (and subsequently) clarified by issuance of the "Revised Wage and Price Standards" on December 13, 1978.

It would seem instructive and useful in thinking about the problem to illustrate some of the effects of the guideline's "core" standards (as opposed to subsequent revisions) had they applied to rate increases before state regulatory commissions in calendar year 1977. That is, what would the picture be if the President's program and these standards had applied to gas and electric rate increases "requested" in 1977, "granted" in 1977 and "pending" before state regulatory commissions on December 31, 1977.

This exercise makes the provisional assumption that other things are being held constant. If the voluntary wage and price program had been introduced in October 1976, it is unrealistic to presume that the actual results would be the same as those presented below. This restriction should be kept in mind in examining the following findings.

Under the new guidelines, the maximum price increase allowed for an individual firm is one half of one percentage point below the average annual rate of price increases during 1976-1977.[31] However, the program's stipulated ceiling on 1979 price hikes is 9.5%. Therefore, if a firm had raised its prices an average of 5% during 1976-1977, it would be constrained to a 4.5% increase in 1979. However, if the 1976-1977 average price increase was 12%, the firm would be restricted to the 9.5% price increase ceiling in 1979 in lieu of 11.5% (12.0-0.5).

Application of the "core" standards of the President's guidelines to electric and gas utility rate increases "requested" in calendar year 1977 reveals some interesting "if-history." We found that the average percentage rate increase requested by electric companies in 1977 was 16.51%.[32] Gas companies requested an average 12.48% rate hike.

Of 172 electric companies for which requested percentage rate increases were exhibited in the Congressional Research Services (CRS) Study, Electric and Gas Utility Rate and Fuel Adjustment Clause Increases, 1977,[33] 146 (84%) were above the economy-wide target, and 121 (70%) were over the individual firm maximum.

A tabulation of gas companies reveals that 76 of 103 firms (74%) topped the general economic goal of 5.75% and 55 companies (53%) made requests in excess of the 9.5% allowable firm maximum.

Table 13 shows rate increases "requested" for both gas and electric companies during 1977 by states[34] The table shows 40 states requesting electric rate increases with all but Virginia surpassing 5.75%. In the case of gas companies, the table shows that 29 of 33 states on average topped the guidelines economy-wide target of 5.75%.

Utilizing data provided to the Congressional Research Service it was possible to calculate average percentage rate increases "granted" by states. These figures are also shown in Table 1 3 along with the rate increases "requested" for both gas and electric companies in 1977.

State Commissions in 1977 granted electric companies rate increases in such a way that 33 of 40 states realized average increases above the 5.75% target set by the President's guidelines.[35] For these 33 states the mean rate increase "granted" was 12.23%.

TABLE 13

ELECTRIC AND GAS UTILITY RATE INCREASES (Averages)
REQUESTED AND GRANTED IN 1977 BY STATES

	Electric		Gas	
	% Increase (a) Requested	% Increase (b) Granted	% Increase (a) Requested	% Increase (b) Granted
Alabama	26.62	11.81	-	-
Alaska	38.16	35.40	-	-
Arizona	23.00	18.69	12.00	18.61
Arkansas	8.92	6.10	9.93	0.10
California	31.70	14.21	17.90	7.01
Colorado	13.55	11.39	12.60	11.61
Connecticut	16.10	5.97	7.20	2.93
Delaware	17.90	17.90	14.57	11.94
Dist. of Columbia	None	-	None	-
Florida	19.48	10.48	18.10	13.59
Georgia	17.48	15.44	4.90	3.54
Hawaii	15.00	10.29	-	-
Idaho	23.02	10.11	2.90	2.13
Illinois	16.34	11.12	7.32	5.21
Indiana	25.40	16.48	-	-
Iowa	6.60	4.49	6.60	5.51
Kansas	17.06	7.96	9.01	3.85
Louisiana	17.95	0.57	19.55	8.37
Maine	10.56	6.54	None	-
Maryland	14.72	12.57	5.82	5.45
Massachusetts	15.33	11.55	16.45	8.00
Michigan	10.00	5.00	7.80	2.56
Minnesota	14.41	11.78	7.74	5.66

TABLE 13 Continued

	Electric		Gas	
	% Increase (a) Requested	% Increase (b) Granted	% Increase (a) Requested	% Increase (b) Granted
Mississippi	None	-	None	-
Missouri	16.67	8.41	9.61	5.32
Montana	28.00	12.25	30.00	23.39
New Hampshire	7.13	7.13	9.36	8.77
New Jersey	18.50	8.80	10.00	4.01
New York	8.88	5.59	12.51	10.22
No. Carolina	13.94	10.95	6.96	2.80
No. Dakota	15.61	11.80	7.76	6.60
Ohio	21.00	12.90	20.54	15.93
Oregon	22.32	19.65	7.53	4.48
Pennsylvania	-	-	-	-
Puerto Rico	None	-	None	-
Rhode Island	6.95	5.14	11.60	3.76
So. Carolina	13.25	9.54	None	-
So. Dakota	15.86	5.01	20.35	6.99
Tennessee	None	-	7.00	2.57
Texas	None	-	-	-
Utah	15.39	12.30	-	-
Vermont	16.47	16.11	None	-
Virginia	3.28	2.64	3.90	3.90
Virgin Islands	None	-	None	-
Washington	-	-	-	-
West Virginia	13.58	7.95	32.87	29.30
Wisconsin	7.92	8.52	2.56	1.54
Wyoming	16.70	11.51	39.00	10.05

Notes:

(a) These figures were found by calculating the average rate increase "requested" for each state from company data provided in the CRS study.

(b) These averages were calculated by finding the rate revenues before the rate increase was granted for each firm within the state. The percentage rate increase for each firm in the state was then calculated and the average was then computed.

Source: U.S. Senate, Electric and Gas Utility Rate and Fuel Adjustment Clause Increases, 1977, Subcommittee on Intergovernmental Relations and the Subcommittee on Energy, Nuclear Proliferation and Federal Services of the Committee on Governmental Affairs, U.S. Senate, by the Economics Division, Congressional Research Service, Library of Congress; Sept. 1978, Appendix Table B-V, pp. CRS 41 - CRS 59.

For the 39 states "requesting" increases in excess of 5.75%, the average increase "granted" was 11.01%, 5¼ percentage points above the target. The mean increase "granted" for all 40 states was 10.80%.

Turning to the gas companies, we found that 15 of the 33 states were granted rate increases on average in excess of 5.75%. The mean increase "granted" in these 15 states was 12.69%.

Of the 29 states "requesting" increases above 5.75%, the mean increase "granted" was 8.49%. For all 33 states the average "granted" rate increase was 7.80%.

Electric and gas utility rate increases "pending" before State Public Utility Commissions in December 1977 is shown in Table 14. From the data provided by the Congressional Research Service, average percentage rate increases "requested" were calculated for each state listed. Ninety six (96) electric companies and ninety seven (97) gas companies were identified as having rate increases pending in December 1977. 36/

In the case of electric companies, 33 of 34 states with rate hikes "pending" were in excess of the 5.75% target. The average rate increase pending before commissions in all 34 states was 16.06%, 10 percentage points over the target.

In the case of gas companies, 24 of 27 states were above the target with an average rate boost of 12.76% requested by all 27 states.

Furthermore, 21 states and D.C. had both gas and electric rate increases pending before State Commissions in excess of the guideline's target.

TABLE 14

ELECTRIC AND GAS UTILITY RATE INCREASES (Averages)
PENDING BEFORE STATE PUBLIC UTILITY COMMISSIONS
DEC. 1977, BY STATES*

State	Electric % Increase Requested	Gas % Increase Requested
Alabama	None	None
Alaska	23.21	None
Arizona	None	None
Arkansas	12.17	5.80
California	15.09	20.65
Colorado	14.39	12.82
Connecticut	None	11.49
Delaware	17.57	None
Dist. of Columbia	15.90	12.56
Florida	8.40	None
Georgia	None	None
Hawaii	19.47	10.10
Idaho	36.84	5.60
Illinois	13.40	7.90
Indiana	-	6.00
Iowa	14.03	5.99
Kansas	18.57	25.99
Louisiana	20.00	None
Maine	9.11	None
Maryland	7.60	None
Massachusetts	8.49	None
Michigan	19.00	11.83
Minnesota	16.20	10.80

TABLE 14 Continued

State	Electric % Increase Requested	Gas % Increase Requested
Mississippi	None	None
Missouri	24.10	7.5
Montana	33.60	60.95
New Hampshire	8.25	9.60
New Jersey	15.24	19.00
New York	14.88	7.15
No. Carolina	18.09	9.73
No. Dakota	None	4.60
Ohio	21.83	18.08
Oregon	6.89	None
Pennsylvania	17.22	9.97
Puerto Rico	None	None
Rhode Island	4.50	15.80
So. Carolina	-	-
So. Dakota	-	-
Tennessee	8.00	10.00
Texas	None	-
Utah	11.42	-
Vermont	17.62	10.00
Virginia	11.83	8.71
Virgin Islands	None	None
Washington	28.00	5.80
West Virginia	20.22	None

Note:

*These figures were found by calculating the average rate increase "requested" for each state from company data provided by the CRS study.

Source: U.S. Senate, Electric and Gas Utility Rate and Fuel Adjustment Clause Increases, 1977, Subcommittee on Intergovernmental Relations and the Subcommittee on Energy, Nuclear Proliferation and Federal Services of the Committee on Governmental Affairs, U.S. Senate, by the Economics Division, Congressional Research Service, Library of Congress; Sept. 1978, Appendix Table B-VI, pp. CRS 61-CRS 73.

By focusing on individual companies, it was found that 86 (89%) of the 96 identified electric companies in the CRS study were above the economy-wide target, and 68 firms (70%) requested hikes in excess of the allowable firm maximum. In the case of gas companies, 70 of the 97 firms (72%) requested increases over the 5.75% standard and 45 firms (46%) climbed beyond the 9.5% ceiling.

Therefore, the "core" standards of the inflation-fighting scheme promulgated by the White House would have required at least 70% of the electric firms submitting rate increases for approval to adjust requests downward in their attempt to boost rates above the 9.5% ceiling. And at least 46% of the gas utilities would have been required to make downward adjustments in their requests had companies complied with the newly proposed guidelines.

Table 15 shows the total dollar amount of electric and gas rate increases actually "granted" in 1977 and the total rate increase had the President's guidelines applied.

Column (1) shows the total rate increases actually granted in 1977. Column (2) shows the total rate increase which would have resulted if those companies granted increases in excess of the economy-wide target had been restricted to the 5.75% goal. Similarly, Column (4) shows the total rate increase if those companies granted increases above the 9.5% maximum had been restricted to this ceiling.

TABLE 15

ELECTRIC AND GAS UTILITY RATE INCREASES IN 1977 - ACTUAL AND IF THE PRESIDENT'S ANTI-INFLATION GUIDELINES HAD APPLIED (MILLIONS OF DOLLARS)

	(1)a Total Rate Increases Actually Granted in 1977	(2)b If 5.75% Maximum Target had Applied	(3) Difference Col.(1)-Col.(2)	(4)c If 9.5% Max. had Applied	(5) Difference Col.(1)-Col.(4)
Electric	$1,924.2	$1,193.1	$731.1	$1,678.5	$245.7
Gas	292.9	212.1	80.8	256.3	36.6
Total	$2,217.1	$1,405.2	$811.9	$1,934.8	$282.3

Notes:

(a) This total represents rate increases granted in 45 states, the District of Columbia, Puerto Rico, and the Virgin Islands, as reported in Appendix Table B-V of the CRS study.

(b) Column (2) shows the estimated total dollars of rate increases if all of the commissions represented in the CRS study had restricted rate increases to 5.75%.

(c) Column (4) shows the estimated total dollars of rate increases if all of the commissions represented in the CRS study had restricted rate increases to 9.5%.

Source: Author's calculations derived from data available in the U.S. Senate's, Electric and Gas Utility Rate and Fuel Adjustment Clause Increases, 1977, Subcommittee on Intergovernmental Relations and the Subcommittee on Energy, Nuclear Proliferation and Federal Services of the Committee on Governmental Affairs, U.S. Senate, by the Economics Division, Congressional Research Service, Library of Congress; Sept. 1978, Appendix Table B-V.

The table reveals that had the guidelines applied in 1977 with each firm being restricted to a 5.75% rate increase, total electric rate increases would have been reduced by $731.1 million (Col. 3). Total gas rate increases would have been reduced by $80.8 million resulting in a total reduction for both gas and electric rate hikes of $811.9 million.

Had each firm been restricted to a 9.5% rate increase, electric rate hikes would have been $245.7 million less than were actually granted (Col. 5). Gas rate increases would have been reduced by $36.6 million resulting in a total reduction of $282.3 million from the level of rate increases actually granted in 1977.

Table 16 shows the total dollar amount of electric and gas rate increases "pending" before State Commissions in December 1977 and the total rate increase which would have been "pending" if the President's guidelines had applied.

Column (1) shows the total rate increase requested by companies in 1977. Column (2) shows the total rate increase which would have been "requested" by companies had all firms restricted their rate increase "requests" to 5.75%. Column (4) shows the requested increase had all companies restricted their proposed rate hikes to 9.5%.

The table reveals that had the guidelines applied with each firm being restricted to a 5.75% rate increase, total electric rate increases "pending" before State Commissions in December 1977 would have been $1,101.1 million less than the amount actually pending (Col. 2). Requested gas rate increases would have been reduced by $494.4 million, resulting in a $1,595.5 million reduction in rate increase requests.

Had each firm restricted its request to a 9.5% rate hike, electric rate increases pending would have declined by $1,680.5 million (Col. 4). Gas rate increases pending would have been reduced by $754.8 million resulting in a total reduction of $1,069.8 million.

TABLE 16

ELECTRIC AND GAS UTILITY RATE INCREASES PENDING IN 1977 - REQUESTED AND IF THE PRESIDENT'S ANTI-INFLATION GUIDELINES HAD APPLIED (MILLIONS OF DOLLARS)

	(1)a Total Rate Increases Actually Requested	(2)b If 5.75% Maximum Target had Applied	(3) Difference Col.(1)-Col.(2)	(4)c If 9.5% Max. had Applied	(5) Difference Col.(1)-Col.(4)
Electric	$2,373.4	$1,101.1	$1,272.3	$1,680.5	$692.9
Gas	1,131.7	494.4	637.3	754.8	376.9
Total	$3,505.2	$1.595.5	$1.909.6	$2.435.3	$1,069.8

Notes:

(a) This total represents rate increases granted in 45 states, the District of Columbia, Puerto Rico, and the Virgin Islands as reported in Appendix Table B-VI of the CRS study.

(b) Column (2) shows the estimated total dollars of rate increases "requested" if all companies had restricted their requests to 5.75%.

(c) Column (4) shows the estimated total dollars of rate increase "requests" if all companies had restricted their requests to 9.5%.

Source: Author's calculations derived from data available in the U.S. Senate's, Electric and Gas Utility Rate and Fuel Adjustment Clause Increases, 1977, Subcommittee on Intergovernmental Relations and the Subcommittee on Energy, Nuclear Proliferation and Federal Services of the Committee on Governmental Affairs, U.S. Senate, by the Economics Division, Congressional Research Service, Library of Congress; Sept. 1978, Appendix Table B-VI.

C. Is Turnaround Fair Play?

Unless one believes that the U.S. economy has an inexorable and endless upward bias in price levels, i.e. that the economy is permanently assigned to inflation, there will be a time in "the cycle" where prices stabilize or even turn down. What then might be the outline of the regulatory response to a resumption of relative price level stability?

Other parts of this report have traced the regulatory response on the upswing as involving the adoption of various devices and practices to accommodate to the inflationary circumstance. But if public utility regulation is to be something more than merely "accounting for inflation," it should have a planned regulatory response for the downswing.

In some respects a "switching of sides" can be expected to take place. One might find utilities anxious to get fuel adjustment clauses and indexing arrangements off their books; replacement cost accounting and marginal cost pricing might be less attractive to them as might the use of future test years in estimating revenue needs. Even regulatory delay might be valued as helpful, requiring full evidentiary hearings to lower rates and revenues

From the commission point of view in a period of sustained price level stability, the pressures and rationale for allowing CWIP in the rate base, normalization accounting, preoccupation with rate-of-return on equity rather than rate base, interim rates, and time constraints on commission deliberations would presumably be less strong. State legislatures could be expected to be less prone to intervene on economic issues, like so-called lifeline provisions, and the Congress in a fiscal policy swing might reduce the Investment Tax Credit and Accelerated Depreciation preferences available to utilities under the federal tax code.

Should some or much of this eventuate in the post-inflationary period described, the central task of state commission regulation would then be a clear-headed new appraisal of the capital needs of the industry; a reassessment upward of the actual riskiness of the industry; and a fairminded determination of allowable returns commensurate with these conclusions. Improved and effective commission regulation for all parties is more likely to come in this setting than when regulation is cluttered with gadgets and gimmicks that at best were improvisations of the moment and at worst clouded the focus of regulators for a decade.

FOOTNOTES TO PART II

1. U.S. Congress, Committee Prints, Electric and Gas Utility Rate and Fuel Adjustment Clause Increases, 1976 (and committee prints, same title, for 1977, 1975, and 1974), Senate Committee in Governmental Affairs, prepared by the Economics Division, Congressional Research Service, Library of Congress, July 1977, p. v.

2. Some of these amounts also include a fuel component; i.e., not all fuel-related costs are represented by the FAC totals.

3. Ibid. (1977 Committee Print), p. vii.

4. Public Service Company of New Mexico, Decision and Order, NMPSC, Case No. 1419, Dec. 29, 1979, p. 62.

5. Ibid., pp. 56, 63-68.

6. National Regulatory Research Institute report, The New Mexico Cost-of-Service Index: An Effort in Regulatory Innovation, by A. Kaufman and R. Profozich, May, 1979.

7. Consumers Power Company, 25 P.U.R. 4th 167 (Mich. PSC 1978), appeal pending, Kelley v. PSC, Ingham County Circuit Court, No. 78-22142 AA (filed August 30, 1978).

8. Library of Congress, Congressional Research Service, Economics Division, Memorandum Report to Congressman John E. Moss, Regarding Cost of Including Construction Work in Progress in Rate Base as Proposed by the Federal Power Commission, December 20, 1974; and Federal Power Commission, Office of Economics, An Analysis of the Electric Utility Industry's Financial Requirements, 1974.

9. Testimony of Gordon Corey, Vice Chairman, Commonwealth Edison for his company and Edison Electric Institute before U.S. House Ways and Means Oversight Committee as reported in Electrical Week, April 2, 1979, p. 4.

10. For a thorough analysis of the issue including its legislative, see Occasional Paper No. 1, of the National Regulatory Research Institute, Accelerated Depreciation and the Investment Tax Credit in the Public Utility Industry: A Background Analysis, by Donald W. Kiefer, April 1979.

11. Testimony before the U.S. House Ways and Means Oversight Committee as reported in Electrical Week, April 2, 1979, p. 2.

12. U.S. Congress, Committee Print, Electric and Gas Utility Rate and Fuel Adjustment Clause Increases, op. cit.

13. Public Power Weekly, Newsletter, March 19, 1979, American Public Power Association, Washington, D.C., p. 1.

14. Bureau of National Affairs, Energy Users Report, January 1978, p. 10, reporting on Federal Trade Commission staff report dated December 28, 1977.

15. Solomon Fabricant. A Primer on Productivity, New York, N.Y. Random House (1969), Chapter 9. Much of the discussion that follows draws on this theoretical foundation.

16. Edward F. Renshaw, "Productivity and the Demand for Electricity," Public Utilities Fortnightly (May 6, 1976), pp. 17-20.

17. Ibid.

18. Calculations presented here were based upon data obtained from the Handbook of Labor Statistics, U.S. Dept. of Labor, Bureau of Labor Statistics, 1977.

19. For an extensive treatment of the subjects see John W. Kendrick, Productivity Times in the United States, Princeton, N.J.: Princeton University Press (1961).

20. Ibid.

21. Renshaw, op. cit.

22. Mailgram of November 22, 1978 from Dr. Douglas N. Jones, Director, NRRI, to the Honorable Alfred E. Kahn, Chairman, Council on Wage and Price Stability and Dr. Kahn's reply letter of December 26, 1978.

23. Electrical Week (February 19, 1979), p. 3

24. NARUC Bulletin (March 5, 1979), p. 6.

25. Jan. 26, 1979 Memorandum of Robert Feragen, Administrator, Rural Electrification Administration.

26. Public Power Weekly, Newsletter, (Washington, D.C.: American Public Power Association, March 26, 1979), p. 1.

27. Public Power Weekly, Newsletter, (Washington, D.C.: American Public Power Association, March 5, 1979), p. 2.

28. NARUC Bulletin, op. cit.

29. Colorado Public Utilities Commission, "Statement Regarding Federal Anti-Inflation Program," March 20, 1979.

30. Wall Street Journal, Column 1 (Oct. 25, 1978), p. 3 (continued).

31. *Ibid*.

32. *Electric and Gas Utility Rate and Fuel Adjustment Clause Increases, 1977*, prepared for the Subcommittee on Intergovernmental Relations and the Subcommittee on Energy, Nuclear Proliferation and Federal Services of the Committee on Governmental Affairs, U.S. Senate, by the Economics Division, Congressional Research Service, Library of Congress; September 1978. See Appendix Table B-V, pp. CRS 41 - CRS 59.

33. *Ibid*.

34. The CRS study, Appendix Table B-V, shows data for 45 states, the District of Columbia, Puerto Rico, and the Virgin Islands. Table 1 lists each state and percentage rate increases.

35. *Electric and Gas Utility Rate and Fuel Adjustment Clause Increases, 1977*, *op*. *cit*.

36. *Ibid*., see Appendix Table B-VI, pp. CRS 61 - CRS 73.

PART III - ANALYZING RATES OF RETURN IN REGULATED AND NONREGULATED INDUSTRIES*

*This report was prepared for the National Regulatory Research Institute at The Ohio State University. The views expressed are those of the authors, R. J. Krasniewski and R. J. Murdock, Academic Faculty of Accounting, The Ohio State University, and do not necessarily reflect those of the Institute.

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I. INTRODUCTION

A. Purpose of This Study

Several critical contemporary problems confront the complex society of Twentieth-Century America. Consisting of issues (e.g., inflation and unemployment) which threaten to modify current lifestyles substantially (if they have not already done so), today's agenda offers very few easy choices. Relying frequently on appeals to emotion rather than to sensibility, the public discussions on some of these topics resemble verbal ping-pong matches in which the participants, acting out of self-interest and mutual distrust, fail to appreciate the interdependent nature of their relationship. Popular rhetoric exacerbates the situation. Allegations such as "Business is irresponsible" or "Labor is greedy" or "Consumers are wasteful" simply promote further suspicion and antagonism.

No issue is more heatedly debated than energy. In particular, the battle lines are well drawn when utility rates are discussed. With their advocates challenging virtually every proposed rate increase, consumers seek stable energy prices. Citing the requirement for fair and reasonable profit levels, utilities defend their requests by pointing to large increases in the cost of providing service and to the need to maintain a competitive position in the capital markets. If their securties are not kept attractive to the investment community, expansion to meet future demand is impossible.

The Regulatory Commission is the arena where these conflicts are resolved. Each side offers evidence to support its position. The two sets of "facts" contain conflicting data. On the one hand, the utility is just trying to "rip off" the consumer as much as possible. On the other, the utility is just trying to be "responsive to the needs" of the community it serves and to its owners as well. The compromise decision reached by the commission leaves everyone unhappy.

This study's principal purpose is to shed some light on the "appropriateness" of utility profit levels and thereby elevate the current public debate. With the data currently available, what can be said about public utility rates of return? What observable effects does regulation have? Comparative information, developed as objectively as possible, is the major product of this research effort. Although relying upon data compiled originally by the utility industry (i.e., the financial statements presented in annual reports to stockholders and in registration statements filed with the Securities and Exchange Commission), this study is by no means sponsored by it. Although written and read by utility customers, it is not intended to support the position of any consumer group. All the adjustments to reported data and all the statistical tests are made in the spirit of achieving the highest attainable degree of comparability.

In accord with most empirical research, this study also points to those areas where its principal purpose is difficult to accomplish. How are the comparative analyses performed here affected by the limitations inherent in the data? What <u>can't</u> be said about public utility rates of return? Perhaps more important than the comparisons themselves, these "negative" results are considered at appropriate junctures throughout the report. They offer some insight into the types of information which, if available, could address the unanswered questions, and they document the need for further research.

1. <u>Comparing Profitability Measures for Regulated and Nonregulated Industries</u>

One frequently mentioned purpose of regulation is to ensure that utility profits are no greater than what they would be if the companies were forced to compete. The comparisons analyzed in this section are empirical tests of the degree to which this purpose is achieved. These tests cannot be made solely with reference to utility financial data. Although such an approach would permit conclusions as, "Utility X has a higher rate of return than Utility Y," it fails to relate utilities to competitive sectors of the economy. This type of relationship requires comparisons of utilities with firms in nonregulated industries. Using relative difficulty of entry as a surrogate for the degree of competition existing in an industry, this study compares utility profits with those in three industrial classifications.

Although this extension beyond a mere examination of utility rates of return permits the types of comparisons most relevant to the research question considered here, it also increases the level of complexity inherent in the analysis. Several adjustments to account for the differences between regulated and nonregulated enterprises must be made before any comparisons are performed. The concept of "rate of return" must also be unambiguously defined. Reported financial information prepared in accordance with divergent accounting principles must be reconciled. The degrees of risk associated with utility and nonutility investments must be examined to determine their effects on profit-levels. Finally, consideration must be given to efficiency differences between regulated and nonregulated businesses and to the pricing practices which result from the usual regulatory process.

2. Comparing Rates of Return Allowed by Various Regulatory Authorities

A second major type of comparative analysis is directed toward assessing the degree of uniformity in utility profit levels across jurisdictional lines. Again, the intent is to provide information. Using uniform or equal rates of return for all public utilities as a benchmark (in a manner similar to a "national average"), this approach enables a regulatory body to see "where it stands" in relation to its counterparts throughout the country. Although intrastate activity is not subject to direct scrutiny from Washington, federal officials, desiring some amount of similarity and consistency in the regulatory process, may use the data developed here to determine their future course of action. Several types of comparisons (e.g., State by State, "Flow-Through" States and "Normalized" States, etc.,) are presented.

Because the analysis here is limited to utility financial data, methodological issues differ somewhat from those mentioned in the preceding section. However, utility accounting practices must still be reconciled, and risk levels for investments in various utility securities must be considered. One additional concern involves data limitations caused by the number of firms per regulatory authority.

B. A Brief Look at the Major Components of This Study

Section II presents the conceptual issues which are addressed in the comparison of regulated and nonregulated profit measures. The discussion focuses on regulation's impacts, both intended and unintended, upon utility rates of return. The analysis in Section III begins at the most basic level by comparing rates of return under the assumption that the adjustments made to the reported financial information adequately account for all the major differences which exist between regulated and nonregulated companies. Section IV considers other factors which, because they differ between the two classes of firms, may affect the rate of return comparisons. Section V examines rates of return allowed by regulatory jurisdiction. Finally, Section VI summarizes the results and suggests directions for future research efforts.

II. Regulation's Effects Upon Rates of Return

A. Definitional, Theoretical, and Policy Related Issues

The following six issues, directly or indirectly, intentionally (as a desired outcome of the regulatory process) or inadvertently (as an unavoidable by-product), can have an impact on reported utility profit levels. The first, the definition of rate of return, needs a satisfactory resolution before any meaningful comparisons can be made. The second, the so-called public interest theory of regulation, is the primary rationale underlying this study's comparative analyses. The third, extensive use of financial leverage, illustrates one way in which utility shareholders can circumvent rate of return constraints imposed by regulation. The remaining three issues (investor risk level differences, marginal cost pricing, and rate base inflation) are more troublesome. For each of these a simplifying assumption is made prior to the comparative analysis in Section III. They are then treated seriatim in Section IV.

1. Definition of Rate of Return

Nothing is more fundamental to this study than the meaning of rate of return. On the surface there does not seem to be much confusion concerning this term. For example, an eight percent rate of return simply means that for every $100 invested, $8 is earned. However, at least two major ambiguities occur when this concept is applied simultaneously to utilities and nonregulated businesses.

In general, for a company not subject to regulation, rate of return in an accounting sense means the quotient obtained when net income is divided by total assets (total resources). A measure with the identical name in the utility industry has both its numerator and its denominator determined differently. First, "return" in the regulatory accounting sense includes interest charges along with net income. This is done because of the high degree of financial leverage (the ratio of debt to equity) found in the typical public utility. Second, because a utility is not allowed to earn a return from current ratepayers on construction work in progress (CWIP), "rate base" replaces total assets. Roughly akin to the excess of total assets over CWIP, the rate base, depending upon the regulatory jurisdiction, may involve several other adjustments to total assets.

To reconcile these differences in this report, whenever a rate of return on total assets is calculated, interest charges are included in the numerator. This is applied universally, for utilities and non-utilities alike. Interest is also included in all rates of return on total productive assets (where total productive assets are defined as total assets minus CWIP).[1] Calculated in the same manner for every company (including those which are not regulated), this rate of return on total productive assets is the closest approximation in this study to the utility notion of rate of return on rate base.

In addition to the rates on total assets and on total productive assets, two other series of profitability measures are developed. Constituting returns to common shareholders, both exclude interest from their numerators since interest is the "return" to debt holders. In a parallel manner to the previous discussion, the denominator used to compute the rate of return on common shareholders' productive assets also excludes CWIP.

Thus, rate of return as defined in this study is not the same as a utility's "rate of return," nor is it identical to "rate of return" as the term is conventionally used in the nonregulated sector. Instead it is a compromise measure which captures the essence of both concepts and facilitates comparisons. Finally, to make the data for "Flow Through" and "Normalized" utilities comparable, all rates of return are computed before deducting Federal Income Tax. Section III elaborates on this and other methodological issues.

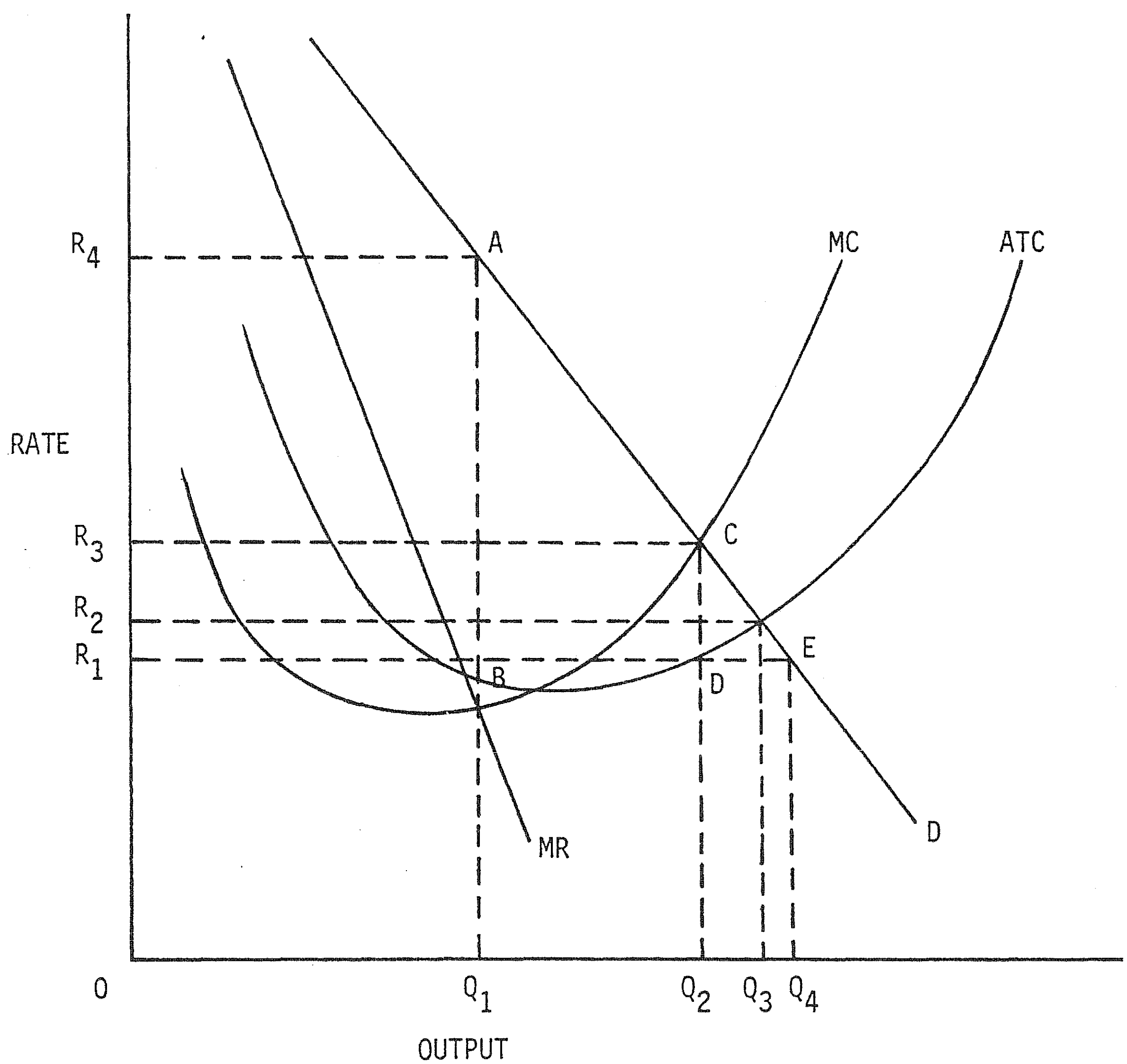
2. From the Public Interest Theory of Regulation: Regulation Should Place a "Ceiling" on a Utility's Rate of Return

This prescription serves as one well-known foundation for regulation's role in utility rate-setting. As a guardian of the public interest, the regulator permits the regulatee only a "normal profit," thereby removing any opportunity to follow monopoly pricing policies. The presumption is that an operation with as many monopolistic attributes as a public utility would, if not subjected to regulatory authority, seek to maximize its profits by restricting output and raising prices. A "normal profit" is that level of earnings which would prevail in a competitive product market. Considered from an investment viewpoint, it is the amount necessary to attract and retain the resources employed in the industry.[2] Conventional economic analysis includes normal profit as a component of a firm's cost curves.

Figure 1 depicts the revenue and cost functions for a utility characterized by increasing costs (i.e., the situation where the incremental cost of providing more output is rising).[3] D is the demand schedule (assumed to have an elasticity coefficient greater than zero) and MR its related marginal revenue curve. ATC is its average total cost curve, and MC is the marginal cost curve. The firm earns a normal profit when, for a given level of output, the rate charged equals average total cost.

FIGURE 1

THE ECONOMIC IMPACT OF REGULATION
UPON A UTILITY WITH INCREASING COSTS



If unregulated and allowed to maximize profits, the utility equates marginal revenue with marginal cost, produces and sells Q_1 at rate R_4, and earns "above normal" profits equal to the area of R_1R_4AB. Regulation must now remove the "monopoly profit."

One approach is to require the utility to sell Q_1 at a rate of R_1. Since this combination is a point on its average total cost curve, the firm would receive only a normal profit. But the havoc resulting from the excess demand (at R_1 quantity demanded is Q_4) would create a rationing system at best and a "black market" at worst. Since consumers are willing to pay R_4 for Q_1, those fortunate enough to purchase some output will easily be able to make substantial profits on subsequent re-sale.

Instead, the regulator attempts to determine that output where demand equals average total cost. In Figure 1 the desired output is Q_3.[4] Here normal profits are earned, and no excess demand exists. As long as demand is not perfectly inelastic, the quantity consumed in the regulatory solution exceeds the amount provided by the unregulated monopolist. The rate charged must be lower.

With this directive from economic theory as a norm, Section III proceeds with empirical tests--comparisons of utility profit levels with those in other industrial groups classified by a surrogate for relative degree of competitiveness. Utility rates of return should approximate those in perfectly competitive industries. Other than a utility subject to the regulatory process described here, only firms in perfect competition have market equilibria located on their average total cost curves. Any firm operating in an imperfect market is able to earn some amount of above normal profit. Therefore, since none of the three industrial classifications employed in Section III is perfectly competitive, utilities, if they are regulated in accord with the economic theory discussed here, should have lower rates of return than any of the industrial categories.

3. From the Rate-Setting Process Itself: A Utility is Induced to Use Financial Leverage to Increase Returns to its Common Shareholders

One of the primary reasons for calculating rates of return on shareholders' assets is to determine the effects of financial leverage. With its emphasis placed on the rate of return allowed to be earned on a utility's rate base, regulation may still permit relatively high profit levels on those assets "owned" by the company's common stockholders. The incentive created for rate base increases financed through borrowing is illustrated in the following example.

Assume that a public utility's capital structure is:

	Amount
8% Long-Term Debt	\$ 50
Common Stock	50
Total Capitalization	\$100

Assume further that the utility's total capitalization equals its total assets which in turn equal its rate base. The regulatory authority allows a nine percent rate of return. Finally, assume that the company is planning a major plant expansion. Its current rate of return measures are:

On total assets: $\frac{9}{100} = 9\%$; and

On common shareholders' assets: $\frac{9 - 4}{100-50} = \frac{5}{50} = 10\%$.

Suppose the entity wishes to increase the rate of return for its common stockholders as it builds its new facilities. This can be accomplished by borrowing the necessary construction funds at eight percent. To take an extreme case, assume that the new plant has a cost of \$100 and that debt is used exclusively. The capital structure becomes:

	Amount
8% Long-Term Debt	\$150
Common Stock	50
Total Capitalization	\$200

With the commission still allowing nine percent, rates of return are:

On total assets: $\frac{18}{200} = 9\%$.

On common shareholders' assets: $\frac{18 - 12}{200 - 150} = \frac{6}{50} = 12\%$.

The utility has "leveraged" higher profit levels for its owners. It can improve returns to shareholders by augmenting its rate base through assets acquired with funds borrowed at interest rates which are lower than its allowable rate of return. The results of this leveraging process suggest that returns on utility stockholders' assets may violate the axioms of the risk-return relationship.[5] Further, even though a regulator acting in the public interest imposes a ceiling on a utility's rate of return on total productive assets (rate base), a regulated company can still provide relatively high profits for its common shareholders.[6] Regulated public utilities constitute some of the most highly leveraged companies in the country.[7]

4. <u>From Investment Theory: Because Regulation Removes Most of the Risk Associated with an Investment in Utility Securities, Utility Rates of Return Should be Relatively Low</u>

The ceiling imposed by regulation on a company's rate of return also becomes a "floor." Assuming good estimates of all the variables used in rate-setting (or relatively short "regulatory lag" if the estimates prove inaccurate), utilities are <u>guaranteed</u> a specified level of profit. Premised on the idea that investors are risk averse, investment theory postulates a direct relationship between risk level and rate of return.[8] Risk is a "bad" which, if borne by the investor, must provide compensation in the form of higher anticipated profit levels.

Acting as a form of insurance policy, the regulatory process itself removes much of the potential risk associated with investment in utility securities.[9] Further, because revenues are virtually assured, utilities can engage in much more financial leverage than nonregulated enterprises.

Although used more appropriately as a predictor of returns to shareholders than of returns on total assets, risk-return theory points in the same direction as the public interest theory of regulation: utility rates of return should be relatively low.[10]

5. From Welfare Economics: A Utility Should Promote Societal Efficiency by Using Marginal Cost Pricing

The regulatory "normal profit" outcome occurs when the rate charged to customers equals the utility's average cost of producing output. As Figure 1 illustrates, regulation results in the utility supplying quantity Q_3 at a rate of R_2. But R_2 is also the firm's average total cost per unit when output level Q_3 is attained. Since average total cost includes an allowance for normal profit, this equilibrium position, accomplished through "average cost pricing," keeps utility profits from exceeding those in competitive industries.

Although generally an effective curb on monopolistic pricing practices, average cost pricing may result in an inefficient allocation of society's resources. The issue here centers on the benefits and costs of supplying utility services. The demand schedule reflects the benefits received by consumers. The value placed on the incremental unit purchased is the maximum price a consumer is willing to pay for it.[11] In other words, the demand function can also be labeled the marginal valuation schedule or the marginal benefit curve. In this context, assuming no "externalities" on either side of the market, the socially optimal result occurs when, for the last unit of utility service produced and consumed, marginal benefit and marginal cost are equal. With average cost pricing, this outcome can happen in only the rarest of situations.[12] Thus, another rate-setting procedure merits attention, "marginal cost pricing," a system which attempts to transmit accurate signals to the customer about the cost of resources consumed in providing utility output.

The differences between the two approaches are illustrated in Figure 1. The marginal cost of the last unit purchased at output Q_3 (as determined from the marginal cost curve) exceeds its marginal benefit (as reflected in the demand curve). In removing from the utility the opportunity for "above normal profit," regulation based on average cost pricing also causes, from a societal viewpoint, "excessive" amounts of resources devoted to utility service because the price charged is "too low." On the other hand, without any specific concern for utility profit levels, marginal cost pricing results in a socially efficient quantity (Q_2) by charging a rate of R_3.[13,14]

If marginal cost pricing does prevail in the utility industry, the results of the comparative analyses in this study are difficult to anticipate. Unlike the earlier discussion where the removal of monopolistic opportunities and the existence of low risk levels led to the conclusion that utility rates of return on total productive assets should be low, a marginal cost pricing policy means that utility profit levels should exceed those found in perfectly competitive industries.[15] But, since no industrial group considered here is perfectly competitive, no prediction can be made about the relationship between rates of return for utilities using marginal cost pricing and nonutility businesses.[16] Utility profits for justifiable societal reasons could be very high.[17]

6. <u>From the Rate-Setting Process Itself: Rate Base Inflation</u>

A public utility attempting to increase its <u>total</u> profits can pursue either (or both) of the following strategies:

(a) Convince its regulatory commission to increase the rate of return allowed on its rate base; or

(b) Augment its rate base.

In many situations, the latter alternative may be preferable from the utility's viewpoint. Since it places the company in the undesirable position of drawing attention to its rate of return, the first option may not be politically expedient. The second approach, which may or may not involve "rate base inflation," effectively increases profits without exposing the utility to as much public criticism.

Thus, the regulatory process contains an inducement for augmenting the rate base. As used in this study, the term "rate base inflation" means any "improper" increase in a utility's rate base. In a world of "perfect" regulation, no rate base inflation would exist. However, because it may be difficult to discern, rate base inflation looms as a possibility for virtually every rate-setting process. A utility can accomplish it in two general ways: (1) Accumulate unnecessary plant and equipment (i.e., inefficient use of resources); and (2) Treat cost-of-service items as fixed assets for regulatory accounting purposes (i.e., "capitalize the paper clips"). The effects of these two tactics on the rate of return calculations are considered in the following discussion.

a. Accumulation of Unnecessary Assets in the Rate Base

Implicit in the behavior of nonregulated industry is the assumption that each firm, acting in its own self-interest, strives to operate as efficiently as possible. Producing any level of output at its minimum possible cost is a necessary (albeit not a sufficient) condition for profit maximization. Requiring use of the most up-to-date technology, this concept of efficiency is impounded in the usual microeconomic theory of the firm.

However, net income is determined differently in the regulated sector. Prohibiting the public utility from maximizing its profit as a monopolist, regulation instead allows the firm to earn a fair and equitable return on its rate base. Starting with the contribution of Averch and Johnson,[18] a substantial amount of literature has evolved concerning the inefficient use of inputs by regulated entities.[19] Overcapitalization, the so-called "A-J Effect," occurs as regulation encourages the substitution of capital for labor. The overall impact of this "build up the rate base" tactic on the comparative analyses performed in this study is difficult to assess. The efficiency or resource utilization issue (i.e., the built-in regulatory incentive for employing "too many" assets) is not reflected in the rate of return on total productive assets. All assets included in the rate base--those actually needed and the "excess"--earn the same rate of return. However, although unobservable in a statistical sense, one result can be inferred. To the extent that this rate base strategy is nothing more than a preferred (from the utility's standpoint) option to the otherwise viable alternative of securing a higher allowable rate of return from the regulatory authority, rates of return on total assets (and on total productive assets as well) will be lower than they otherwise would have been.

On the other hand, rates of return for common stockholders' assets adjust as "rate base management" techniques are used. The stockholders' profitability measures change according to the method used to finance the "unnecessary"[20] assets. If debt is used, rates of return on owners' productive assets increase.[21] They decrease if the rate base is inflated with common shareholders' funds.[22] However, these movements occur regardless of whether the rate base increase is a manifestation of this inflation strategy or is a truly necessary addition.

b. <u>Capitalizing Cost-of-Service Items</u>

This second type of rate base inflation is strictly an accounting phenomenon. It does not involve any inefficiency in an economic sense. It can best be illustrated by an example.

> Consider two utilities (A and B). At the outset each has the same values for the relevant variables in the regulatory setting:

Annual cost-of-service:		$300
Rate base:		$200
Allowable rate of return on rate base:		10%
Capitalization:		
	8% long-term debt:	$100
	Common stock	100
	Total	$200

> Assume that the utility distributes annually to its shareholders cash dividends equal to the smaller of: (1) shareholders' profits; or (2) available cash (i.e., total revenues minus the cash component of cost-of-service minus purchases of assets included in the rate base minus interest paid). Available cash will be less than shareholders' profits when some of the latter are "plowed back" into the business (i.e., when purchases of rate base assets exceed depreciation).

TABLE 1

FIVE-YEAR RESULTS FOR COMPANY A

						Common Shareholders'		Rate of Return	
Year	Rate Base	10% Return Received on Rate Base	Cost-of-Service	Total Revenues	Interest	Total Profits	Cash Dividends	On Total Productive Assets	On Common Shareholders' Productive Assets
1	$200	$20	$300	$320	$8	$12	$12	10%	12%
2	200	20	300	320	8	12	12	10%	12%
3	200	20	300	320	8	12	12	10%	12%
4	200	20	300	320	8	12	12	10%	12%
5	200	20	300	320	8	12	12	10%	12%
Total	$1,000	$100	$1,500	$1,600	$40	$60	$60	-	-
5-Year Average	$ 200	$ 20	$ 300	$ 320	$ 8	$12	$12	10%	12%

Source: Author's hypothetical calculations.

TABLE 2

FIVE-YEAR RESULTS FOR COMPANY B

Year	Rate Base*	10% Return Received On Rate Base	Cost-of-Service	Total Revenues	Interest	Common Shareholders'		Rate of Return	
						Total Profits	Cash Dividends	On Total Productive Assets	On Common Share-holders' Productive Assets
1	$209	$20.9	$292	$312.9	$8	$12.9	$4.9	10%	11.83%
2	216	21.6	294	315.6	8	13.6	7.6	10%	11.72%
3	221	22.1	296	318.1	8	14.1	10.1	10%	11.65%
4	224	22.4	298	320.4	8	14.4	12.4	10%	11.61%
5	225	22.5	300	322.5	8	14.5	14.5	10%	11.60%
Total	$1,095	$109.5	$1,480	$1,589.5	$40	$69.5	$49.5	-	-
5-Year Average	$ 219	$ 21.9	$ 296	$ 317.9	$ 8	$ 13.9	$ 9.9	10%	11.68%

*Average of beginning-of-year and end-of-year amounts.

Source: Author's hypothetical calculations.

For Utility A, assume that none of the values stated above change over a five-year time period. Increases in the rate base exactly offset annual depreciation. Long-term debt outstanding is constant. Table 1 presents the results for Company A.

Utility A depicts a "steady-state" situation. Utility B is identical to A from an economic viewpoint but its accounting is slightly more imaginative. Each year Utility B takes $10 of cost-of-service and places it in its rate base. With a five-year useful life, this amount is depreciated at the rate of $2 per year. Thus, Company B's annual cost-of-service will be $290 plus the depreciation on this "new component" of its rate base. Its results are contained in Table 2.

Company B's outcome for Year 5 becomes its "steady-state" for all future periods. When compared with A, B, through its $10 annual accounting ploy, achieves a permanent twelve and one-half percent rate base increase (from $200 to $225). Even with this increase, B's total revenues in Year 5 exceed A's by only .78%. Starting with Year 5, B's shareholders' annual profits and cash dividends will be greater than those of A by $2.5. This was accomplished by "plowing back" profits amounting to $20 (the difference between $69.5 and $49.5) in Years 1 through 4. This "investment" will now pay an annual rate of return of twelve and one-half per cent ($2.5 divided by $20).

Viewed another way, B's shareholders have "invested" much less than $20. Rather, for the five-year period, the investment is only $10.5 (the difference between A's total cash dividends of $60 and B's $49.5), making the rate of return on the incremental investment 23.8%. Further, because they will now receive $2.5 per year more in cash dividends, B's shareholders' total cash dividend receipts will exceed A's owners' total cash inflow by the end of Year 10.[23]

As a comparison of the last two columns in both tables demonstrates, this type of rate base inflation has no effect on the rate of return on total productive assets and it reduces the rate of return on common shareholders' productive assets. The permanent difference in this example is four-tenths of one percent (12% for Utility A to 11.6% for Utility B). "Reverse" financial leverage has occurred (i.e., relatively less long-term debt exists since the rate base increase is financed through shareholders' contributions.

c. Rate Base Inflation and Financial Leverage

The following table summarizes the relevant relationships between rate base inflation and financial leverage. In each situation a utility capitalized with both debt and common stock (with the interest rate lower than the allowable rate of return on rate base) has increased its rate base. The company has not requested its regulator to approve any change in its allowable rate of return. The results presented in the table are based on the presumption that "perfect regulation" discerns proper and improper rate base increases.

> Situation 1 combines rate base inflation with increased financial leverage. If, in this case, the regulator would not have allowed any increase in the rate of return on the uninflated rate base, the rate of return on total productive assets as calculated in this study is not affected by rate base inflation. But the increased rate of return on common shareholders' productive assets caused by the additional borrowing would not have been achieved.
>
> One example of Situation 2 is the accounting stratagem of including a cost-of-service item in the rate base. This causes the computed rate of return on shareholders' productive assets to decrease, although with proper accounting (an important aspect of "perfect regulation") it should either remain unchanged or increase (through regulatory approval of a higher allowable rate of return).
>
> Involving no rate base inflation, Situations 3 and 4 demonstrate the effects of changing a utility's capitalization proportions. The rate of return computations in this study reflect such changes and therefore are "correct" for these two cases.[24] Like Situation 2, Situation 4 is an example of "reverse" financial leverage where the seemingly inconsistent combination of higher total profits and lower rates of return on common shareholders' productive assets occurs.

B. Summary

With the definition of rate of return altered somewhat to permit its consistent application to all companies included in this study, the comparisons in the following section are directed toward ascertaining the degree to which the prescription from the public interest theory of regulation is fulfilled. Is the utility industry able to earn above normal profits or does regulation limit earnings to levels existing in more competitive sectors? However, the outcomes of the analysis can be

TABLE 3

EFFECTS OF RATE BASE INFLATION AND FINANCIAL LEVERAGE

Situation	Was the Rate Base Increase Proper?	Was the Rate Base Increase Financed Through Additional Borrowing?	Effect of Rate Base Increase on <u>Total</u> Profits		Effect of Rate Base Increase on Rate of Return on Total Productive Assets		Effect of Rate Base Increase on Rate of Return on Common Shareholders' Productive Assets	
			Actual	With "Perfect Regulation"[1]	As Computed in this Study	With "Perfect Regulation"[1]	As Computed in this Study	With "Perfect Regulation"[1]
1	NO[2]	YES[3]	INCREASE	INCREASE[4]	NONE	INCREASE[4]	INCREASE	INCREASE[4]
2	NO[2]	NO	INCREASE	INCREASE[4]	NONE	INCREASE[4]	DECREASE	INCREASE[4]
3	YES	YES[3]	INCREASE	INCREASE	NONE	NONE	INCREASE	INCREASE
4	YES	NO	INCREASE	INCREASE	NONE	NONE	DECREASE	DECREASE

[1]"Perfect regulation" disallows all improper rate base increases. Regulator may or may not permit an increase in the utility's allowable rate of return on its uninflated rate base.

[2]Rate base inflation exists.

[3]Increased amount of financial leverage occurs.

[4]Only to the extent that the regulator would have permitted rate of return on uninflated rate base to increase. If no such permission would have been granted, "NONE" becomes the correct entry in the table.

Source: See Tables 1 and 2 and text.

interpreted as evidence that the regulatory process has several other effects. The statistical results may have occurred because regulation emphasizes something other than removing monopoly profits or because it elicits (perhaps unintentionally) certain types of behavior from the businesses it oversees.

First, regulation may induce a utility to engage in a substantial amount of financial leverage. As long as the interest rate on its debt is less than its rate of return allowed by the regulator, borrowing to augment the rate base will increase returns on common shareholders' assets. Thus, a relatively low rate of return on total assets may be accompanied by a high profit level on owners' assets. Some evidence that this leverage phenomenon does occur has already been provided.[25]

Second, regulation may be attempting to ensure that utility rates of return are in line with the level of risk borne by utility investors. In general, the amount of such risk should be small. Thus, both the public interest theory of regulation and the risk-return relationship suggest relatively low rates of return on utility shareholders' assets.

Third, regulation may be seeking optimal societal resource allocation through marginal cost pricing. Because profit levels are only of incidental importance with this policy, it can be consistent with virtually any rate of return. If regulated firms have increasing average total costs, marginal cost pricing permits them to achieve higher profit levels than perfectly competitive entities.

Finally, regulation may inadvertently encourage "rate base inflation," a technique which provides higher total profits without requiring the regulator to allow an increase in the rate of return on rate base. To the extent that, in lieu of obtaining such an increase, a utility acquires "unnecessary" assets, its rate of return on total productive assets will be lower than it otherwise would have been. If rate base inflation is accomplished through additional borrowing, rates of return on shareholders' assets will reflect the financial leverage effect previously discussed. However, rate base inflation and increased financial leverage are essentially two different tactics. Each can exist independently of the other. A related strategy involves including in the rate base an outlay which more appropriately would be classified as a component of cost-of-service. More of an accounting ploy than an intentional failure to seek a higher allowable rate of return, this approach can be used even in a situation where the propriety of the actual expenditure is unimpeachable.[26] Assuming that no additional borrowing occurs, a type of "reverse" financial leverage takes place. When contrasted with the "proper" accounting treatment (i.e., recovery through cost-of-service), this results in higher <u>total</u> profits but lower rates of return on common shareholders' assets. Although the effects of rate base inflation on the rate of return measures analyzed in this study can be determined at the conceptual level, they are unobservable in the actual statistical comparisons. This occurs for two reasons: (1) the increase in the utility's rate of return which would have been allowed by the regulator on the uninflated rate base is unknown; and (2) rate base inflation itself is unobservable.

As this discussion demonstrates, there will likely be competing explanations for the results of the rate of return comparisons. After a treatment of methodological issues, the next section proceeds with statistical tests solely as they relate to this study's primary research issue: How do utility profitability measures compare with those of nonregulated industries? Underlying this analysis are three assumptions: (1) risk levels for investments in regulated and nonregulated companies are the same; (2) utilities employ average cost pricing; and (3) rate base inflation does not exist. The effects of relaxing these assumptions are considered in a subsequent section of this report.

III. Methodology and Data Analysis

A. Calculating Rates of Return

As mentioned previously,[27] for each company analyzed in this study, interest charges are added back to reported net income for two of the four rate of return measures. This is done so that rates of return on total assets and on total productive assets are computed in a manner similar to that employed in the regulatory process. Four other issues related to the rate of return computations are treated in the following discussion.

1. Adding Back Federal Income Tax

Besides interest, federal income tax is also added back to reported net income. This facilitates the comparisons involving "flow-through" utilities. According to the flow-through concept of regulation, a company must immediately pass on to its customers the income tax savings associated with accelerated depreciation and the investment tax credit.[28] Only income taxes actually paid or currently payable (net of all current investment tax credits) may be recovered as part of cost-of-service. Accordingly, an income statement for a flow-through utility will report this amount as income tax expense.

Flow-through is an accounting method which is found most often in regulated industry. With regard to the tax savings derived from accelerated depreciation, generally accepted accounting principles preclude nonregulated businesses from using flow-through.[29] However, because of Congressional legislation, the accounting profession may not recommend an appropriate treatment for the investment tax credit.[30]

"Normalization" (frequently called "Deferral" or "Tax Allocation" outside the regulatory sector), the other principal accounting method, permits a utility to recover in its cost-of-service the income tax which would have been paid if the company's reported net income was also the amount currently subject to income tax. Since the tax return's accelerated depreciation normally exceeds the annual report's straight-line depreciation, a deferred tax liability accounts for that part of the utility's tax expense which is not currently payable. The investment tax credit is considered a reduction in the cost of an asset and is reflected in lower depreciation expense throughout the asset's useful life. The following example illustrates potential distortions to the rate of return comparisons caused by the differences between flow-through and normalization accounting.

Assume that two public utilities are identical in all respects except that one (Company N) is allowed to normalize the tax difference caused by accelerated depreciation while the other (Company F) must flow-through this amount to its customers. Both are required to use straight-line depreciation for rate-making purposes. Each company's relevant data are:

Rate Base	\$ 300
Operating Expenses (other than depreciation and taxes)	50
Straight-line Depreciation	30
Accelerated Depreciation	45
Interest on Long-Term Debt	12
Allowed Return (10% of Rate Base)	30
Tax Rate	50%

Revenue Requirements for N(RR_N) would be:

$$RR_N = 50 + 30 + .5(RR_N - 50 - 30 - 12) + 30$$

$$.5\ RR_N = 64$$

$$RR_N = 128$$

For F, Revenue Requirements (RR_F) would be:

$$RR_F = 50 + 30 + .5(RR_F - 50 - 45 - 12) + 30$$

$$.5\ RR_F = 56.5$$

$$RR_F = 113$$

Assuming that all actual amounts equal the corresponding estimates made during rate-setting, the Income Statements for the two utilities would be:

	N	F
Revenues	$ 128	$ 113
Operating Expenses	(50)	(50)
Depreciation	(30)	(30)
Federal Income Taxes	(18)	(3)
Operating Income	$ 30	$ 30
Interest Charges	(12)	(12)
Net Income	$ 18	$ 18

The use of net income (or net income plus interest charges) will result in the two utilities having identical rate of return measures. But this result occurs only because Company N reports as expense both current and deferred income taxes while Company F's report includes only current income taxes. If both companies account for income taxes in the same manner, N's after tax income will exceed F's by $7.5. Since the nonregulated firms use N's reporting method, F is transformed into a normalized utility. F's financial statement now includes income taxes of $10.5, the appropriate normalized expense on its before tax income of $21 (Revenues of $113 less expenses--including interest--of $92). F's after tax operating income falls to $22.5, and the comparison with N's $30 reflects the $7.5 difference.[31]

As compared with attempting to "normalize" the flow-through utilities, the approach employed in this study, adding back reported income tax expense for all companies, accomplishes the desired objective in a simpler fashion. All rates of return are based on "pre-tax" income data. In the previous example, with taxes added back, N's "income" ($48) exceeds F's ($33) by $15, the difference in revenues caused by N's ability to normalize. This is consistent with the $7.5 after tax difference discussed earlier. By adding back taxes aberrations resulting from the manner in which a company accounts for its tax payments to the Federal Government do not affect the rate of return measures.[32]

2. <u>Subtracting Allowance for Funds Used During Construction to Determine the Return to Productive Assets</u>

To design the analysis as closely as possible to the regulatory setting, two of the rate of return series relate income to productive assets. As discussed earlier, this concept of productive assets [total assets minus construction work in progress (CWIP)], roughly approximates regulation's rate base computation.[33] Besides the reduction in the asset base for CWIP, a utility's allowance for funds used during construction (AFUDC) is subtracted from reported income in the numerator of all rates of return on productive assets.

Unique to regulated industry, AFUDC is the net cost during the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used.[34] By capitalizing interest and an imputed amount of income on equity funds, a utility is able to "earn a return" on assets being constructed. Although this method, especially its imputation of earnings on owner-provided capital, is a violation of generally accepted accounting principles applicable to nonregulated entities, regulatory accounting rules permit it as a substitute for including CWIP in the utility's rate base.

The increase in reported income resulting from this practice is considered necessary for a utility to maintain a competitive position in the capital markets. This is especially true in recent times when many regulated firms have substantial amounts committed to currently "unproductive" assets. Potential investors in utility securities understand that AFUDC accounting will enhance operating profits once construction is deemed complete.[35] Any rate of return solely on productive assets would not include AFUDC. Thus, reported income is reduced appropriately for all such profitability measures computed in this study.

3. <u>Measuring Returns to Common Shareholders' Assets</u>

In a manner similar to a settlement in liquidation, a "residual claims" approach is used to calculate the two sets of profitability measures on common shareholders' assets.[36] To derive the earnings applicable to total common stockholders' assets, pre-tax reported net income is reduced by dividends on preferred stock. The assets available to common shareholders are those which remain after the "claims" of all other investors and creditors have been "settled" (i.e., total assets, less liquidating value of preferred stock, less long-term debt, less current liabilities). The resulting rate of return on total common shareholders' assets in many instances approximates the familiar "rate of return on equity." However, all the profitability measures computed in this study are rates of return on assets. In no case is a rate of return computed by dividing some amount of income by part or all of the stockholders' equity reported on the balance sheet.

Although the computation of this first profitability measure on common shareholders' assets is fairly straight-forward, some philosophical issues exist concerning the measurement of the rate of return on common stockholders' productive assets. The fundamental question is: Who has "claims" on the CWIP? Consistent with the method for deriving the rate of return on total productive assets, the approach used involves removing AFUDC from the numerator and CWIP from the denominator of the rate of return on total common shareholders' assets. Since all other claims have already been satisfied, this method is based on the premise that all CWIP "belongs" to the common shareholders. With CWIP likely categorized among the company's least desirable assets, this is a highly probable outcome of a residual-claim liquidation settlement.[37]

4. An Algebraic Representation of the Four Rate of Return Measures

The four rates of return which emerge from the methodology discussed above can be expressed with the following algebraic notation. In all cases the subscript "it" means "for company i in year t." Let

I_{it} = After-tax net income;

T_{it} = Income tax expense;

INT_{it} = Interest expense;

$AFUDC_{it}$ = Allowance for funds used during construction;

PD_{it} = Dividends on preferred stock;

TA_{it} = Average total assets;

$CWIP_{it}$ = Average construction work in progress;

$LIQPF_{it}$ = Average liquidating value of preferred stock;

LTD_{it} = Average long-term debt; and

CL_{it} = Average current liabilities.

a. Measure 1:

$$R1_{it} = \frac{I_{it} + T_{it} + INT_{it}}{TA_{it}}$$

$R1_{it}$ = Accounting Rate of Return on Total Assets

This measure is the reported pre-interest and pre-tax accounting rate of return on total assets.

b. Measure 2:

$$R2_{it} = \frac{I_{it} + T_{it} + INT_{it} - AFUDC_{it}}{TA_{it} - CWIP_{it}}$$

$R2_{it}$ = Accounting Rate of Return on Total Productive Assets

This measure can be viewed as the pre-interest and pre-tax accounting rate of return on total productive assets which would have been reported by utilities if they were required to employ the accounting procedures of the nonregulated sector (i.e., if utilities were not allowed to increase reported income by AFUDC). Also, since AFUDC is not available, Measures 1 and 2 will be identical for all nonregulated companies with no CWIP. If a nonregulated entity has some CWIP, its Measure 2 will always exceed its Measure 1.

c. Measure 3:

$$R3_{it} = \frac{I_{it} + T_{it} - PD_{it}}{TA_{it} - LIQPF_{it} - LTD_{it} - CL_{it}}$$

$R3_{it}$ = Accounting Rate of Return on Total Common Shareholders' Assets

This measure is the pre-tax rate of return on common shareholders' total assets. It is developed according to the generally accepted notion that common stockholders have a residual claim to their company's resources.

d. Measure 4:

$$R4_{it} = \frac{I_{it} + T_{it} - PD_{it} - AFUDC_{it}}{TA_{it} - LIQPF_{it} - LTD_{it} - CL_{it} - CWIP_{it}}$$

$R4_{it}$ = Accounting Rate of Return on Common Shareholders' Productive Assets

Measure 4 defines the common shareholders' pre-tax rate of return on their share of the company's productive assets. This rate of return is based on the assumption that partially completed, specifically designed assets (i.e., CWIP) are the least desirable in any liquidation settlement and are therefore left in their entirety to the common shareholders.[38] Also, just as with Measures 1 and 2, a nonregulated company with no CWIP will have identical Measures 3 and 4. If such a firm has CWIP, its Measure 4 will always exceed its Measure 3.

B. Nonregulated "Industries": The Three Barrier-to-Entry Groups

The utility rates of return are compared with corresponding measures for seventy-one nonregulated companies partitioned into three groups according to relative difficulty of entry. Each group contains leading representatives from several relatively concentrated industries. Thus, each firm has the attributes associated with the oligopolistic form of market structure.

Relative difficulty of entry is a frequently used surrogate for the degree of competitiveness existing within an industry.[39] The conventional analysis is based on the assumption that difficulty of entry and degree of competition vary inversely. Thus, the most competitive set of firms is the "low barrier-to-entry" group. A lesser degree of competition exists in the "medium barrier-to-entry" category, and the least competitive firms are placed in the "high barrier-to-entry" group.

As mentioned throughout this report, the results of the statistical tests will indicate the "position" of the regulated firms in relation to the barrier-to-entry categories. If regulation removes all opportunity for above normal profit, utility rates of return will be less than the corresponding measures for all three barrier-to-entry groups. Even the low barrier group cannot be considered perfectly competitive. On the other hand, utility returns approximating those in any of the three groups (especially the medium barrier or the high barrier group) indicate that regulated companies are able to achieve profit levels in excess of those existing in the more competitive sectors of the economy.

C. Sample Selection

The firms analyzed in this study were chosen as follows:

1. Initial Requirements

a. Electric Utilities

Inclusion on the Utility COMPUSTAT tape[40] was the first criterion for selection of the electric utilities. This guarantees the availability of data items unique to regulated industry (e.g., AFUDC).

b. Nonregulated Companies

To the greatest extent possible, Mann's sample of firms comprising the three barrier-to-entry groups was replicated.[41] Thus, the first selection of nonregulated businesses was based on two conditions: (1) Availability on the general COMPUSTAT tape; and (2) Membership in Mann's sample. As Sullivan's study[42] demonstrated, some of Mann's firms have been merged out of existence. Further, not all of Mann's "surviving" companies meet the criteria for inclusion on the COMPUSTAT tape. Accordingly, firms available on COMPUSTAT were chosen as replacements for most of these "missing" companies. In each case the substitute firm was selected from the same industry as the company it replaced.

2. Further Requirements

After the original selection of company names as above, the following additional information was necessary for inclusion in the final sample: (1) Availability on the COMPUSTAT tape of all data items being analyzed for the entire ten-year period 1967-1976; and (2) Existence of stock price data for at least sixty consecutive months during this ten-year period, a requirement for the estimation of shareholder risk.

For the rate of return comparisons the following number of firms were actually used:

	Number
Normalized Electric Utilities	82
Flow-through Electric Utilities	30
Low Barrier-to-Entry Companies	28
Medium Barrier-to-Entry Companies	24
High Barrier-to-Entry Companies	19

D. Ten-Year Time Period

To provide useful, unbiased results, each company's rate of return measures are examined over the ten-year period 1967-1976. This is a long enough period to ensure that one- or two-year aberrations in the data caused by economic factors (i.e., inflation) or company-specific timing differences (i.e., regulatory lag) do not have an undue influence on the rates of return.[43] Conversely, a ten-year period is of short enough duration to allow the study's data and comparisons to reflect permanent economic changes. In addition to the 1973-74 oil embargo, the specific time period studied contains periods of peace and war, inflation and stable prices, expensive and inexpensive energy. This diversity should greatly enhance the generalizability of the study's conclusions.

In order to perform the statistical tests, the ten-year average rates of return for every firm in each of the five classifications (e.g., flow-through utilities, medium barrier-to-entry companies, etc.) are further combined into unweighted means. The "average" rate of return on total assets, then, for any group of regulated or nonregulated firms is:

$$\overline{R1} = \frac{1}{n} \sum_{i=1}^{n} \frac{1}{10} \sum_{t=1}^{10} R1_{it};$$

where all variables are defined as before and n = the number of firms in this particular category. Thus, each group of companies has four "overall average" rates of return. Each of these measures is the unweighted mean of the appropriate series of ten-year averages for every firm in the group. Each group's four rates of return are then statistically compared with the corresponding measures of one or more of the four other sets of companies.

E. Testing Hypotheses: Statistical Comparisons of the Rates of Return

Beginning with an examination of profitability measures for normalized and flow-through utilities, the statistical comparisons proceed to test hypotheses concerning rates of return for regulated and nonregulated entities. These hypotheses are directed toward determining whether or not a statistically significant difference exists between one or more of the overall average rates of return for one group of firms and the corresponding measure(s) for another category of companies. As mentioned at the conclusion of Section II,[44] three assumptions underly this analysis: (1) risk levels for investments in regulated and nonregulated businesses are the same; (2) utilities employ average cost pricing; and (3) rate base inflation does not exist. The effects of relaxing these assumptions are discussed in Section IV.

1. Normalized and Flow-Through Electric Utilities

As mentioned previously,[45] in some regulatory jurisdictions, (i.e., the "Normalized" States) a utility is allowed to recover through cost-of-service the entire income tax expense (including the amount deferred due to the use of accelerated depreciation for tax purposes) that would arise by applying the set of statutory rates to its reported pre-tax net income. Conversely, other authorities (e.g., the "Flow-Through" States) determine a utility's rate structure including only those income taxes currently paid. Since these two views on the amount of recoverable costs naturally lead to different allowable revenues,[46] accounting rates of return within the utility industry could easily be affected by this philosophical split over income tax expense. To determine if tax recovery policy has a significant impact on utility profit levels and, in fact, to determine if all subsequent statistical tests must consider the two views of regulation separately (thereby partitioning the sample of regulated firms into the normalized and the flow-through groups), the following hypotheses were tested:

> H_0: Rates of return within the electric utility industry are the same regardless of the income tax recovery policy used by the regulator; and
>
> H_A: Rates of return within the electric utility industry differ significantly according to the income tax recovery policy used by the regulator.

These hypotheses can be stated in a more formal, mathematical manner as follows:

$$H_0: \overline{U_1} = \overline{U_2}; \quad \text{and}$$
$$H_A: \overline{U_1} \neq U_2;$$

where $\overline{U_1}$ = vector of the four overall average rates of return for normalized utilities; and

$\overline{U_2}$ = vector of the four overall average rates of return for flow-through utilities.

To overcome the problems inherent with repeated pair-wise comparisons of the profitability measures, the above hypotheses advocate a simultaneous test of all the rates of return. Thus, the Hotelling T^2 test[47] is used. Conceptually, this is a simultaneous comparison of the significance of the Student T test[48] for each rate of return measure. Rejection of the null hypothesis is interpreted as meaning that the two vectors of profitability measures differ (at the prespecified level of significance). In other words, one or more of the rates of return in one vector differ significantly (in a statistical sense) from the corresponding measure(s) in the other vector.

The complete results of the above test as applied to rates of return for normalized and flow-through utilities are presented in Table 4. The null hypotheses was rejected at the .01 level of significance. An interpretation of this result is that there is only one chance in one hundred (on the average) that the return measures examined come from the same

TABLE 4

COMPARISON OF RISK AND RETURN FOR NORMALIZED
ELECTRIC UTILITIES AND FLOW-THROUGH ELECTRIC
UTILITIES (1967-1976)

Flow-Through Utility — Return Measure

COMPANY NAME	1	2	3	4	5	RISK
ALLEGHENY POWER SYSTEM	0.093	0.089	0.170	0.164	0.154	0.525
CENTRAL VERMONT PUB SERV	0.067	0.063	0.093	0.083	0.078	0.766
COLUMBUS & SOUTHERN OHIO	0.085	0.082	0.143	0.225	0.121	0.603
CONCORD ELECTRIC CO	0.083	0.082	0.140	0.139	0.133	[illegible]
GREEN MOUNTAIN POWER CORP	0.073	0.067	0.114	0.096	0.093	1.063
NEVADA POWER CO	0.085	0.080	0.127	0.129	0.092	0.650
NORTHEAST UTILITIES	0.076	0.069	0.120	0.108	0.091	0.582
OHIO EDISON CO	0.099	0.096	0.172	0.206	0.147	0.432
PENNSYLVANIA POWER & LIGHT	0.086	0.082	0.159	0.199	0.133	0.441
PORTLAND GENERAL ELECTRIC CO	0.086	0.086	0.131	0.187	0.110	0.444
PUBLIC SERVICE CO OF N H	0.083	0.080	0.146	0.144	0.129	0.564
PUGET SOUND POWER & LIGHT	0.073	0.072	0.113	0.126	0.103	0.476
SOUTHERN CALIF EDISON CO	0.078	0.077	0.129	0.138	0.122	0.382
UNITED ILLUMINATING CO	0.082	0.080	0.156	0.394	0.138	0.412
ARIZONA PUBLIC SERVICE CO	0.075	0.075	0.125	0.166	0.111	0.491
CENTRAL HUDSON GAS & ELEC	0.080	0.077	0.143	0.138	0.125	0.480
CINCINNATI GAS & ELECTRIC	0.101	0.097	0.193	0.200	0.176	0.284
CONSOLIDATED EDISON OF N.Y.	0.064	0.061	0.093	0.088	0.080	0.802
DAYTON POWER & LIGHT	0.092	0.088	0.171	0.178	0.153	0.479
DELMARVA POWER & LIGHT	0.085	0.079	0.143	0.134	0.118	0.472
LONG ISLAND LIGHTING	0.085	0.084	0.156	0.187	0.135	0.530
NEW YORK STATE ELEC & GAS	0.078	0.076	0.131	0.140	0.119	0.534
NIAGARA MOHAWK POWER	0.068	0.064	0.109	0.107	0.091	0.490
ORANGE & ROCKLAND UTILITIES	0.076	0.073	0.128	0.119	0.113	0.637
PACIFIC GAS & ELECTRIC	0.080	0.078	0.133	0.132	0.118	0.240
PACIFIC POWER & LIGHT	0.074	0.070	0.117	0.115	0.099	0.487
ROCHESTER GAS & ELECTRIC	0.077	0.075	0.126	0.122	0.114	0.606
SAN DIEGO GAS & ELECTRIC	0.079	0.078	0.124	0.127	0.113	0.511
TUCSON GAS & ELECTRIC	0.090	0.087	0.152	0.155	0.128	0.532
WASHINGTON WATER POWER	0.083	0.081	0.147	0.145	0.142	0.282
AVERAGE	0.081	0.078	0.137	0.153	0.119	0.524

Normalized Utility — Return Measure

	1	2	3	4	5	Risk
AMERICAN ELECTRIC POWER	0.083	0.076	0.135	0.131	0.099	0.516
ATLANTIC CITY ELECTRIC	0.085	0.081	0.157	0.182	0.133	0.555
BANGOR HYDRO-ELEC CO	0.079	0.078	0.148	0.147	0.143	0.524
BLACK HILLS POWER & LIGHT CO	0.092	0.094	0.155	0.191	0.153	0.428
BOSTON EDISON CO	0.084	0.075	0.123	0.102	0.093	0.525
BRASCAN LTD-CL A	0.078	0.073	0.073	0.065	0.065	0.614
CAROLINA POWER & LIGHT	0.091	0.086	0.151	0.139	0.112	0.609
CENTRAL & SOUTH WEST CORP	0.121	0.122	0.211	0.222	0.209	0.383
CENTRAL MAINE POWER CO	0.090	0.090	0.160	0.164	0.156	0.310
CLEVELAND ELECTRIC ILLUM	0.103	0.101	0.183	0.503	0.166	0.384
COMMONWEALTH EDISON	0.096	0.091	0.168	0.168	0.150	0.307
COMMUNITY PUBLIC SERVICE	0.099	0.099	0.177	0.176	0.175	0.425
DETROIT EDISON CO	0.078	0.072	0.118	0.102	0.093	0.714
DUKE POWER CO	0.088	0.080	0.148	0.160	0.106	0.612
DUQUESNE LIGHT CO	0.092	0.089	0.169	0.197	0.146	0.504
EASTERN UTILITIES ASSOC	0.086	0.085	0.139	0.236	0.122	0.761

TABLE 4 (CONTINUED)

Normalized Utility

NEW ENGLAND ELECTRIC SYSTEM	0.083	0.080	0.150	0.146	0.135	0.533
OKLAHOMA GAS & ELECTRIC	0.110	0.110	0.216	0.239	0.210	0.342
OTTER TAIL POWER CO	0.093	0.096	0.174	0.614	0.170	0.231
POTOMAC ELECTRIC POWER	0.076	0.081	0.120	0.168	0.130	0.440
PUBLIC SERVICE CO OF IND	0.112	0.113	0.203	0.233	0.198	0.423
PUBLIC SERVICE CO OF N MEX	0.103	0.103	0.180	0.201	0.171	0.592
SAVANNAH ELEC & POWER	0.085	0.082	0.132	0.144	0.106	0.537
SOUTHERN CO	0.089	0.086	0.146	0.191	0.124	0.504
SOUTHWESTERN ELEC SERVICE	0.097	0.096	0.203	0.202	0.201	0.371
SOUTHWESTERN PUBLIC SERV CO	0.109	0.109	0.226	0.248	0.222	0.374
TAMPA ELECTRIC CO	0.097	0.094	0.174	0.182	0.161	0.773
TEXAS UTILITIES CO	0.120	0.120	0.229	0.261	0.222	0.199
TOLEDO EDISON COMPANY	0.096	0.098	0.199	0.228	0.169	0.418
UNION ELECTRIC CO	0.080	0.077	0.140	0.150	0.122	0.400
UPPER PENINSULA POWER	0.085	0.084	0.147	0.146	0.144	0.440
UTAH POWER & LIGHT	0.081	0.080	0.135	0.145	0.123	0.344
VIRGINIA ELECTRIC & POWER	0.085	0.077	0.135	0.175	0.097	0.617
BALTIMORE GAS & ELECTRIC	0.096	0.094	0.175	0.368	0.157	0.420
CENTRAL ILLINOIS LIGHT	0.095	0.094	0.165	0.201	0.152	0.487
CENTRAL ILL PUBLIC SERVICE	0.101	0.100	0.189	0.203	0.179	0.567
CONSUMERS POWER CO	0.085	0.081	0.137	0.136	0.122	0.711
FITCHBURG GAS & ELEC LIGHT	0.083	0.082	0.119	0.117	0.110	0.387
ILLINOIS POWER CO	0.108	0.106	0.205	0.209	0.195	0.497
INTERSTATE POWER CO	0.089	0.089	0.190	0.239	0.185	0.436
IOWA ELECTRIC LIGHT & PWR	0.084	0.078	0.140	0.118	0.112	0.713
IOWA-ILLINOIS GAS & ELEC	0.100	0.094	0.180	0.169	0.160	0.734
IOWA POWER & LIGHT	0.092	0.092	0.177	0.191	0.175	0.353
IOWA PUBLIC SERVICE CO	0.098	0.095	0.175	0.178	0.166	0.304
IOWA SOUTHERN UTILITIES CO	0.118	0.118	0.206	0.217	0.202	0.571
KANSAS POWER & LIGHT	0.108	0.107	0.187	0.192	0.182	0.281
LAKE SUPERIOR DIST POWER CO	0.085	0.086	0.153	0.160	0.155	0.315
LOUISVILLE GAS & ELECTRIC	0.120	0.125	0.216	0.244	0.225	0.436
MADISON GAS & ELECTRIC CO	0.088	0.086	0.141	0.207	0.127	0.367
MISSOURI PUBLIC SERVICE CO	0.090	0.086	0.187	0.171	0.168	0.631
MONTANA POWER CO	0.111	0.111	0.179	0.184	0.176	0.311
NEW ENGLAND GAS & ELECTRIC	0.087	0.085	0.146	0.147	0.135	0.529
NORTHERN INDIANA PUBLIC SERV	0.106	0.105	0.203	0.225	0.190	0.337
NORTHERN STATES POWER	0.093	0.087	0.182	0.184	0.158	0.477
NORTHWESTERN PUBLIC SERV CO	0.093	0.093	0.169	0.337	0.154	0.392
PHILADELPHIA ELECTRIC CO	0.085	0.081	0.135	0.180	0.107	0.438
PUBLIC SERVICE CO OF COLO	0.080	0.077	0.142	0.146	0.129	0.365
PUBLIC SERVICE ELEC & GAS	0.079	0.075	0.125	0.136	0.106	0.609
ST JOSEPH LIGHT & POWER	0.095	0.094	0.179	0.187	0.172	0.599
SIERRA PACIFIC POWER CO	0.079	0.076	0.120	0.116	0.110	0.502
SOUTH CAROLINA ELEC & GAS	0.088	0.085	0.145	0.163	0.127	0.841
SOUTHERN INDIANA GAS & ELEC	0.120	0.117	0.220	0.215	0.210	0.445
WISCONSIN ELECTRIC POWER	0.100	0.099	0.185	0.185	0.181	0.140
WISCONSIN POWER & LIGHT	0.108	0.108	0.209	0.236	0.201	0.419
WISCONSIN PUBLIC SERVICE	0.106	0.105	0.210	0.232	0.200	0.291
MONTANA-DAKOTA UTILITIES	0.092	0.090	0.156	0.150	0.150	0.262
AVERAGE	0.095	0.093	0.167	0.195	0.154	0.473

T^2 Statistic All Measures Simultaneously	35.714 √
T Statistic Risk Level	1.351
√ Significant at .01 Level	

population of companies. Thus, at least with respect to the rates of return calculated in this study, the electric utility industry must be viewed as consisting of two distinct types of firms. The statistical comparisons of rates of return for regulated and nonregulated entities must be performed separately for the normalized and the flow-through utilities.

2. Generalized Hypotheses

All other statistical comparisons discussed in this section involve testing the following sets of hypotheses.

a. One

H_0: $\overline{U_1} = \overline{U_2}$; and

H_A: $\overline{U_1} \neq \overline{U_2}$;

where $\overline{U_1}$ = vector of the four overall average rates of return for one set of firms in the electric utility industry (i.e., either normalized or flow-through); and

$\overline{U_2}$ = vector of the four overall average rates of return for one group of nonregulated companies (i.e., either low, medium or high barrier-to-entry).

b. Two

H_0: $\overline{\gamma_1} = \overline{\gamma_2}$; and

H_A: $\overline{\gamma_1} \neq \overline{\gamma_2}$;

where $\overline{\gamma_1}$ = vector of the two overall average rates of return on common shareholders' assets (Measures 3 and 4) for one set of firms in the electric utility industry; and

$\overline{\gamma_2}$ = vector of the two overall average rates of return on common shareholders' assets (Measures 3 and 4) for one group of nonregulated companies.

c. Three

H_0: $\rho_1 = \rho_2$; and

H_A: $\rho_1 \neq \rho_2$;

where ρ_1 = overall average rate of return on common shareholders' total assets (Measure 3) for one set of firms in the electric utility industry; and

ρ_2 = overall average rate of return on common shareholders' total assets (Measure 3) for one group of nonregulated companies.

To ensure simultaneous comparison of the rates of return, the Hotelling T^2 test is used for the first two sets of hypotheses described above. Because it considers the differences between utilities and non-utilities for only one of the overall average return measures, the third set of hypotheses requires no simultaneous testing. Accordingly, the Student T test suffices in this situation.

3. Comparing Rates of Return for Regulated and Nonregulated Companies

Each of the six regulated/nonregulated comparisons involves a separate set of tests of the three generalized hypotheses. For each test, primary attention is focused on the null hypothesis (i.e., the one designated as H_0). If it is rejected (i.e., if the related T^2 or T statistic is significant), then the two rate of return vectors (or, with the third set of hypotheses, the two rates of return) under analysis are considered to be different. If the null hypothesis is not rejected (i.e., if the related T^2 of T statistic is insignificant), then the two rate of return vectors (or the two rates of return) are not considered to be different (i.e., in a statistical sense the two rate of return series likely come from the same population of firms).

a. Normalized Utilities and Low Barrier-to-Entry Companies

The detailed numerical results of this comparison are presented in Part A of Table 5. Test of null hypothesis one yields a T^2 statistic which is significant at the .01 level, while the T^2 statistic for the test of null hypothesis two is insignificant. The T statistic for the test of null hypothesis three is almost zero and, of course, is insignificant. Thus, since the results from testing hypotheses two and three demonstrate that rates of return on shareholders' assets for the two groups are not statistically different, the rejection of null hypothesis one implies that the normalized utilities' rates of return on total assets and on total productive assets are significantly less than corresponding measures for the low barrier-to-entry firms.[49]

TABLE 5

Comparison of Risk and Return for Normalized Electric Utilities and Barrier-to-Entry Groups (1967-1976)

Electric Utility	Return Measure				
COMPANY NAME	1	2	3	4	RISK
AMERICAN ELECTRIC POWER	0.083	0.076	0.135	0.131	0.516
ATLANTIC CITY ELECTRIC	0.085	0.081	0.157	0.182	0.555
BANGOR HYDRO-ELEC CO	0.079	0.078	0.148	0.147	0.524
BLACK HILLS POWER & LIGHT CO	0.092	0.094	0.155	0.191	0.428
BOSTON EDISON CO	0.084	0.075	0.123	0.102	0.525
BRASCAN LTD-CL A	0.078	0.073	0.073	0.065	0.614
CAROLINA POWER & LIGHT	0.091	0.096	0.151	0.189	0.609
CENTRAL & SOUTH WEST CORP	0.121	0.122	0.211	0.222	0.388
CENTRAL MAINE POWER CO	0.090	0.090	0.160	0.164	0.310
CLEVELAND ELECTRIC ILLUM	0.103	0.101	0.183	0.503	0.384
COMMONWEALTH EDISON	0.096	0.091	0.168	0.168	0.307
COMMUNITY PUBLIC SERVICE	0.099	0.099	0.177	0.176	0.435
DETROIT EDISON CO	0.078	0.072	0.118	0.102	0.714
DUKE POWER CO	0.088	0.080	0.148	0.160	0.612
DUQUESNE LIGHT CO	0.092	0.089	0.169	0.197	0.504
EASTERN UTILITIES ASSOC	0.086	0.085	0.139	0.236	0.761
EDISON SAULT ELECTRIC	0.095	0.094	0.169	0.168	~~0.0~~
EL PASO ELECTRIC CO	0.121	0.120	0.220	0.232	0.358
EMPIRE DISTRICT ELECTRIC CO	0.102	0.099	0.180	0.174	0.326
FLORIDA POWER & LIGHT	0.106	0.106	0.175	0.236	0.575
FLORIDA POWER CORP	0.099	0.096	0.170	0.212	0.636
GENERAL PUBLIC UTILITIES	0.076	0.071	0.112	0.123	0.629
GULF STATES UTILITIES CO	0.099	0.096	0.181	0.203	0.484
HAWAIIAN ELECTRIC CO	0.091	0.088	0.146	0.143	0.477
IDAHO POWER CO	0.088	0.086	0.151	0.153	0.363
INDIANAPOLIS POWER & LIGHT	0.105	0.103	0.207	0.267	0.694
KANSAS CITY POWER & LIGHT	0.090	0.089	0.159	0.167	0.481
KANSAS GAS & ELECTRIC	0.103	0.100	0.190	0.284	0.558
KENTUCKY UTILITIES CO	0.105	0.104	0.169	0.180	0.465
MAINE PUBLIC SERVICE	0.091	0.090	0.158	0.155	0.491
MIDDLE SOUTH UTILITIES	0.092	0.089	0.163	0.195	0.417
MINNESOTA POWER & LIGHT	0.089	0.086	0.174	0.169	0.390
NEW ENGLAND ELECTRIC SYSTEM	0.083	0.080	0.150	0.146	0.533
OKLAHOMA GAS & ELECTRIC	0.110	0.110	0.216	0.239	0.342
OTTER TAIL POWER CO	0.093	0.096	0.174	0.614	0.281
POTOMAC ELECTRIC POWER	0.076	0.081	0.120	0.168	0.460
PUBLIC SERVICE CO OF IND	0.112	0.113	0.203	0.233	0.423
PUBLIC SERVICE CO OF N MEX	0.103	0.103	0.180	0.201	0.592
SAVANNAH ELEC & POWER	0.085	0.082	0.132	0.144	0.537
SOUTHERN CO	0.089	0.086	0.146	0.191	0.504
SOUTHWESTERN ELEC SERVICE	0.097	0.096	0.203	0.202	0.371
SOUTHWESTERN PUBLIC SERV CO	0.109	0.109	0.226	0.248	0.374
TAMPA ELECTRIC CO	0.097	0.094	0.174	0.182	0.773
TEXAS UTILITIES CO	0.120	0.120	0.229	0.261	0.199
TOLEDO EDISON COMPANY	0.096	0.098	0.199	0.228	0.418
UNION ELECTRIC CO	0.080	0.077	0.140	0.150	0.400
UPPER PENINSULA POWER	0.085	0.084	0.147	0.146	0.440
UTAH POWER & LIGHT	0.081	0.080	0.135	0.145	0.344
VIRGINIA ELECTRIC & POWER	0.085	0.077	0.135	0.175	0.617

TABLE 5 (CONTINUED)

Electric Utility	Return Measure				
BALTIMORE GAS & ELECTRIC	0.096	0.094	0.175	0.268	0.420
CENTRAL ILLINOIS LIGHT	0.095	0.094	0.165	0.201	0.487
CENTRAL ILL PUBLIC SERVICE	0.101	0.100	0.189	0.203	0.567
CONSUMERS POWER CO	0.085	0.081	0.137	0.136	0.711
FITCHBURG GAS & ELEC LIGHT	0.083	0.082	0.119	0.117	0.287
ILLINOIS POWER CO	0.108	0.106	0.205	0.209	0.497
INTERSTATE POWER CO	0.089	0.089	0.190	0.239	0.436
IOWA ELECTRIC LIGHT & PWR	0.084	0.078	0.140	0.118	0.713
IOWA-ILLINOIS GAS & ELEC	0.100	0.094	0.180	0.169	0.734
IOWA POWER & LIGHT	0.092	0.092	0.177	0.191	0.353
IOWA PUBLIC SERVICE CO	0.098	0.095	0.175	0.178	0.304
IOWA SOUTHERN UTILITIES CO	0.118	0.118	0.206	0.217	0.571
KANSAS POWER & LIGHT	0.108	0.107	0.187	0.192	0.281
LAKE SUPERIOR DIST POWER CO	0.085	0.086	0.153	0.160	0.315
LOUISVILLE GAS & ELECTRIC	0.120	0.125	0.216	0.244	0.436
MADISON GAS & ELECTRIC CO	0.088	0.086	0.141	0.207	0.367
MISSOURI PUBLIC SERVICE CO	0.090	0.086	0.187	0.171	0.631
MONTANA POWER CO	0.111	0.111	0.179	0.184	0.311
NEW ENGLAND GAS & ELECTRIC	0.087	0.085	0.146	0.147	0.529
NORTHERN INDIANA PUBLIC SERV	0.106	0.105	0.202	0.225	0.337
NORTHERN STATES POWER	0.093	0.087	0.182	0.184	0.477
NORTHWESTERN PUBLIC SERV CO	0.093	0.093	0.169	0.337	0.392
PHILADELPHIA ELECTRIC CO	0.085	0.081	0.135	0.180	0.438
PUBLIC SERVICE CO OF COLO	0.080	0.077	0.142	0.146	0.365
PUBLIC SERVICE ELEC & GAS	0.079	0.075	0.125	0.136	0.609
ST JOSEPH LIGHT & POWER	0.095	0.094	0.179	0.187	0.599
SIERRA PACIFIC POWER CO	0.079	0.076	0.120	0.116	0.502
SOUTH CAROLINA ELEC & GAS	0.088	0.085	0.145	0.163	0.841
SOUTHERN INDIANA GAS & ELEC	0.120	0.117	0.220	0.215	0.445
WISCONSIN ELECTRIC POWER	0.100	0.099	0.185	0.185	0.140
WISCONSIN POWER & LIGHT	0.108	0.108	0.209	0.236	0.419
WISCONSIN PUBLIC SERVICE	0.106	0.105	0.210	0.232	0.291
MONTANA-DAKOTA UTILITIES	0.092	0.090	0.156	0.150	0.262
AVERAGE	0.095	0.093	0.167	0.195	0.473

TABLE 5 (CONTINUED)

PART A

COMPARISON WITH LOW BARRIER-TO-ENTRY GROUP (1967-1976)

Company Name	Return Measure 1	2	3	4	RISK
OWENS-ILLINOIS INC	0.103	0.106	0.162	0.171	0.618
ANCHOR HOCKING CORP	0.177	0.177	0.244	0.244	0.736
GOODYEAR TIRE & RUBBER CO	0.121	0.125	0.192	0.207	0.703
FIRESTONE TIRE & RUBBER CO	0.119	0.119	0.182	0.182	0.734
UNITED BANKS OF COLORADO	0.037	0.037	0.010	0.010	0.572
GOODRICH (B.F.) CO	0.076	0.077	0.093	0.095	0.793
INTERCO INC	0.172	0.172	0.273	0.274	0.953
BROWN GROUP INC	0.173	0.173	0.240	0.240	0.735
U S SHOE CORP	0.151	0.152	0.251	0.252	0.942
GENESCO INC	0.108	0.108	0.174	0.177	1.373
CELANESE CORP	0.090	0.094	0.155	0.171	0.561
U S GYPSUM CO	0.110	0.112	0.139	0.142	0.630
NATIONAL GYPSUM CO	0.101	0.101	0.122	0.122	0.839
CPC INTL INC	0.154	0.160	0.235	0.251	0.517
STOKELY-VAN CAMP INC	0.105	0.105	0.135	0.137	0.634
ESMARK INC	0.091	0.093	0.142	0.147	0.473
GENERAL MILLS INC	0.166	0.168	0.364	0.370	0.603
PILLSBURY CO	0.127	0.127	0.231	0.231	0.717
AMERICAN CAN CO	0.109	0.110	0.164	0.169	0.313
CONTINENTAL GROUP	0.134	0.140	0.195	0.211	0.317
ANHEUSER-BUSCH INC	0.185	0.198	0.262	0.291	0.534
PABST BREWING CO	0.182	0.188	0.221	0.229	0.562
SCHLITZ (JOSEPH) BREWING	0.202	0.216	0.277	0.312	0.841
AMERICAN BAKERIES CO	0.036	0.037	0.045	0.046	0.871
BURLINGTON INDUSTRIES INC	0.119	0.121	0.182	0.186	0.889
STEVENS (J.P.) & CO	0.083	0.084	0.112	0.114	0.740
CONE MILLS CORP	0.103	0.103	0.129	0.129	0.744
DAN RIVER INC	0.054	0.054	0.044	0.044	0.912
AVERAGE	0.121	0.124	0.177	0.184	0.717

T^2	Statistic Normalized Utilities Vs. Low Barrier Group	
	(1) All Measures Simultaneously	136.193 √
	(2) Return Measures 3 & 4	3.767
T	Statistic Return Measure 3	0.503
T	Statistic Risk Level	33.523 √
√	Significant at .01 Level	

TABLE 5 (CONTINUED)

PART B

COMPARISON WITH MEDIUM BARRIER-TO-ENTRY GROUP (1967-1976)

Company Name	Return Measure 1	2	3	4	RISK
ALUMINUM CO OF AMERICA	0.087	0.090	0.121	0.130	0.516
REYNOLDS METALS CO	0.062	0.064	0.081	0.089	1.017
KAISER ALUMINUM & CHEM CORP	0.079	0.080	0.122	0.127	1.182
NABISCO INC	0.176	0.176	0.283	0.283	0.760
UNITED BRANDS	0.066	0.066	0.058	0.058	1.319
EXXON CORP	0.220	0.220	0.331	0.331	0.276
TEXACO INC	0.143	0.143	0.193	0.193	0.553
MOBIL CORP	0.180	0.180	0.294	0.294	0.478
STANDARD OIL CO (INDIANA)	0.139	0.139	0.197	0.197	0.104
U S STEEL CORP	0.073	0.073	0.101	0.101	0.646
BETHLEHEM STEEL CORP	0.081	0.081	0.109	0.109	0.899
JORGENSEN (EARLE M.) CO	0.176	0.178	0.263	0.267	0.589
PROCTER & GAMBLE CO	0.227	0.227	0.311	0.311	0.377
COLGATE-PALMOLIVE CO	0.169	0.169	0.260	0.260	0.552
INTL HARVESTER CO	0.084	0.084	0.113	0.113	0.538
ALLIS-CHALMERS CORP	0.059	0.059	0.053	0.053	0.893
DEERE & CO	0.135	0.135	0.211	0.211	0.413
KENNECOTT COPPER CORP	0.098	0.098	0.110	0.110	0.325
PHELPS DODGE CORP	0.134	0.134	0.162	0.162	0.472
IDEAL BASIC INDUSTRIES INC	0.123	0.128	0.156	0.166	0.882
LONE STAR INDUSTRIES	0.093	0.093	0.125	0.126	0.678
GENERAL PORTLAND INC	0.085	0.095	0.101	0.101	0.940
U S SHOE CORP	0.151	0.152	0.251	0.252	0.942
COMPO INDS	0.080	0.080	0.098	0.098	0.678
AVERAGE	0.122	0.122	0.171	0.173	0.664

T^2 Statistic Normalized Utilities Vs. Medium Barrier Group	
(1) All Return Measures Simultaneously	226.317 √
(2) Return Measures 3 & 4	4.079
T Statistic Return Measure 3	0.126
T Statistic Risk Level	19.919 √
√ Significant at .01 Level	

TABLE 5 (CONTINUED)

PART C

COMPARISON WITH HIGH BARRIER-TO-ENTRY GROUP (1967-1976)

Company Name	Return Measure 1	2	3	4	RISK
GENERAL MOTORS CORP	0.197	0.200	0.279	0.286	0.619
FORD MOTOR CO	0.111	0.113	0.165	0.170	0.576
CHRYSLER CORP	0.064	0.066	0.097	0.100	1.316
WRIGLEY (WILLIAM) JR CO	0.240	0.242	0.298	0.302	0.475
REYNOLDS (R.J.) INDS	0.253	0.258	0.363	0.373	0.468
AMERICAN BRANDS INC	0.158	0.158	0.270	0.272	0.516
LIGGETT GROUP	0.129	0.129	0.191	0.191	0.618
PHILIP MORRIS INC	0.166	0.172	0.330	0.359	0.273
MERCK & CO	0.349	0.358	0.472	0.492	0.264
PFIZER INC	0.169	0.174	0.250	0.264	0.211
SCHERING-PLOUGH	0.320	0.332	0.433	0.456	0.274
ABBOTT LABORATORIES	0.163	0.165	0.242	0.247	0.590
SEAGRAM CO LTD	0.101	0.102	0.134	0.135	0.565
NATIONAL DISTILLERS &CHEMICL	0.117	0.119	0.181	0.187	0.654
WALKER(HIRAM) GOODRHM & WORT	0.187	0.189	0.240	0.242	0.341
TEXASGULF INC	0.168	0.168	0.225	0.225	0.695
REEPORT MINERALS CO	0.130	0.130	0.147	0.147	0.465
PPG INDUSTRIES INC	0.107	0.112	0.143	0.154	0.701
LIBBEY-OWENS-FORD CO.	0.183	0.187	0.310	0.329	0.216
AVERAGE	0.174	0.178	0.251	0.260	0.549

T^2	Statistic Normalized Utilities Vs. High Barrier Group	
	(1) All Return Measures Simultaneously	157.007 √
	(2) Return Measures 3 & 4	45.042 √
T	Statistic Return Measure 3	41.378 √
T	Statistic Risk Measure	3.536
√	Significant at .01 Level	

b. Normalized Utilities and Medium Barrier-to-Entry Companies

The results of this comparison are reported in Part B of Table 5. The T^2 and T statistics for this set of tests have exactly the same significant/insignificant labels as they had in the previous comparison. Thus, the statistical relationships are identical to the ones existing between rates of return for normalized utilities and the low barrier-to-entry group. Even though the utility profitability measures are significantly lower when the four overall average rates of return are compared simultaneously, the common shareholders of the normalized utilities earn a rate of return on their ownership claims which does not differ from that enjoyed by the common shareholders of the medium barrier-to-entry firms.

c. Normalized Utilities and High Barrier-to-Entry Companies

The results of this comparison are contained in Part C of Table 5. The T^2 statistics for the tests of both null hypothesis one and null hypothesis two are significant at the .01 level. Further, the T test rejected null hypothesis three at the .01 level. Thus, the rates of return for normalized utilities are all significantly less than the corresponding measures for the high barrier-to-entry group. Since this set of nonregulated firms represents the most "monopolistic" companies analyzed in this study, the results of these tests provide evidence that regulation removes the potential for monopoly profits.

d. Flow-Through Utilities and Low Barrier-to-Entry Companies

Part A of Table 6 presents the results for this comparison. The T^2 statistic for the test of null hypothesis one is significant at the .01 level. However, the T^2 for the test of null hypothesis two and the T for the test of null hypothesis three are also significant but only at the .05 level. Depending upon the significance level required to reject the null hypothesis (an issue upon which statisticians differ), two interpretations of these results are possible. First, with strict adherence to the .01 level, the rate of return relationships between flow-through utilities and low barrier companies are exactly the same as those between normalized utilities and the low barrier-to-entry group.

TABLE 6

COMPARISON OF RISK AND RETURN FOR FLOW-THROUGH ELECTRIC UTILITIES
AND BARRIER-TO-ENTRY GROUPS (1967-1976)

Company Name	Return Measure				
	1	2	3	4	RISK
ALLEGHENY POWER SYSTEM	0.093	0.089	0.170	0.164	0.525
CENTRAL VERMONT PUB SERV	0.067	0.063	0.093	0.083	0.766
COLUMBUS & SOUTHERN OHIO	0.085	0.082	0.143	0.225	0.603
CONCORD ELECTRIC CO	0.083	0.082	0.140	0.139	
GREEN MOUNTAIN POWER CORP	0.073	0.067	0.114	0.096	1.063
NEVADA POWER CO	0.085	0.080	0.127	0.129	0.650
NORTHEAST UTILITIES	0.076	0.069	0.120	0.108	0.582
OHIO EDISON CO	0.099	0.095	0.172	0.206	0.432
PENNSYLVANIA POWER & LIGHT	0.086	0.082	0.159	0.199	0.441
PORTLAND GENERAL ELECTRIC CO	0.086	0.086	0.131	0.187	0.444
PUBLIC SERVICE CO OF N H	0.083	0.080	0.146	0.144	0.564
PUGET SOUND POWER & LIGHT	0.073	0.072	0.113	0.126	0.476
SOUTHERN CALIF EDISON CO	0.078	0.077	0.129	0.138	0.322
UNITED ILLUMINATING CO	0.082	0.080	0.156	0.394	0.412
ARIZONA PUBLIC SERVICE CO	0.075	0.075	0.125	0.166	0.491
CENTRAL HUDSON GAS & ELEC	0.080	0.077	0.143	0.138	0.480
CINCINNATI GAS & ELECTRIC	0.101	0.097	0.193	0.200	0.284
CONSOLIDATED EDISON OF N.Y.	0.064	0.061	0.093	0.088	0.802
DAYTON POWER & LIGHT	0.092	0.088	0.171	0.178	0.479
DELMARVA POWER & LIGHT	0.085	0.079	0.143	0.134	0.472
LONG ISLAND LIGHTING	0.085	0.084	0.156	0.187	0.530
NEW YORK STATE ELEC & GAS	0.078	0.076	0.131	0.140	0.524
NIAGARA MOHAWK POWER	0.068	0.064	0.109	0.107	0.490
ORANGE & ROCKLAND UTILITIES	0.076	0.073	0.128	0.119	0.637
PACIFIC GAS & ELECTRIC	0.080	0.078	0.133	0.132	0.240
PACIFIC POWER & LIGHT	0.074	0.070	0.117	0.115	0.487
ROCHESTER GAS & ELECTRIC	0.077	0.075	0.126	0.122	0.609
SAN DIEGO GAS & ELECTRIC	0.079	0.078	0.124	0.127	0.511
TUCSON GAS & ELECTRIC	0.090	0.087	0.152	0.155	0.532
WASHINGTON WATER POWER	0.083	0.081	0.147	0.145	0.282
AVERAGE	0.081	0.078	0.137	0.153	0.524

TABLE 6 (CONTINUED)

PART A

COMPARISON WITH LOW BARRIER-TO-ENTRY GROUP (1967-1976)

Company Name	Return Measure 1	2	3	4	RISK
OWENS-ILLINOIS INC	0.103	0.106	0.162	0.171	0.618
ANCHOR HOCKING CORP	0.177	0.177	0.244	0.244	0.736
GOODYEAR TIRE & RUBBER CO	0.121	0.125	0.192	0.207	0.703
FIRESTONE TIRE & RUBBER CO	0.119	0.119	0.182	0.182	0.734
UNITED BANKS OF COLORADO	0.037	0.037	0.010	0.010	0.572
GOODRICH (B.F.) CO	0.076	0.077	0.093	0.095	0.793
INTERCO INC	0.172	0.172	0.273	0.274	0.953
BROWN GROUP INC	0.173	0.173	0.240	0.240	0.735
U S SHOE CORP	0.151	0.152	0.251	0.252	0.942
GENESCO INC	0.108	0.108	0.174	0.177	1.373
CELANESE CORP	0.090	0.094	0.155	0.171	0.561
U S GYPSUM CO	0.110	0.112	0.139	0.142	0.830
NATIONAL GYPSUM CO	0.101	0.101	0.122	0.122	0.839
CPC INTL INC	0.154	0.160	0.235	0.251	0.517
STOKELY-VAN CAMP INC	0.105	0.105	0.135	0.137	0.634
ESMARK INC	0.091	0.093	0.142	0.147	0.473
GENERAL MILLS INC	0.166	0.168	0.364	0.370	0.603
PILLSBURY CO	0.127	0.127	0.231	0.231	0.717
AMERICAN CAN CO	0.109	0.110	0.164	0.169	0.313
CONTINENTAL GROUP	0.134	0.140	0.195	0.211	0.317
ANHEUSER-BUSCH INC	0.185	0.198	0.262	0.291	0.534
PABST BREWING CO	0.182	0.188	0.221	0.229	0.562
SCHLITZ (JOSEPH) BREWING	0.202	0.216	0.277	0.312	0.841
AMERICAN BAKERIES CO	0.035	0.037	0.045	0.046	0.871
BURLINGTON INDUSTRIES INC	0.119	0.121	0.182	0.186	0.889
STEVENS (J.P.) & CO	0.083	0.084	0.112	0.114	0.740
CONE MILLS CORP	0.103	0.103	0.129	0.129	0.744
DAN RIVER INC	0.054	0.054	0.044	0.044	0.912
AVERAGE	0.121	0.124	0.177	0.184	0.717

T^2	Statistic Flow-through Utilities Vs. Low Barrier Group	
	(1) All Return Measures Simultaneously	76.241√
	(2) Return Measure 3 & 4	8.125*
T	Statistic Return Measure 3	6.152*
T	Statistic Risk Measure	10.529√
√	Significant at .01 Level	
*	Significant at .05 Level	

TABLE 6 (CONTINUED)

PART B

COMPARISON WITH MEDIUM BARRIER-TO-ENTRY GROUP (1967-1976)

Company Name	Return Measure 1	2	3	4	RISK
ALUMINUM CO OF AMERICA	0.087	0.090	0.121	0.130	0.516
REYNOLDS METALS CO	0.062	0.064	0.081	0.089	1.017
KAISER ALUMINUM & CHEM CORP	0.079	0.080	0.122	0.127	1.182
NABISCO INC	0.176	0.176	0.283	0.283	0.760
UNITED BRANDS	0.066	0.066	0.058	0.058	1.319
EXXON CORP	0.220	0.220	0.331	0.331	0.276
TEXACO INC	0.143	0.143	0.193	0.193	0.553
MOBIL CORP	0.180	0.180	0.294	0.294	0.478
STANDARD OIL CO (INDIANA)	0.139	0.139	0.197	0.197	0.104
U S STEEL CORP	0.073	0.073	0.101	0.101	0.646
BETHLEHEM STEEL CORP	0.081	0.081	0.109	0.109	0.800
JORGENSEN (EARLE M.) CO	0.176	0.178	0.263	0.267	0.589
PROCTER & GAMBLE CO	0.227	0.227	0.311	0.311	0.377
COLGATE-PALMOLIVE CO	0.169	0.169	0.260	0.260	0.552
INTL HARVESTER CO	0.084	0.084	0.113	0.113	0.538
ALLIS-CHALMERS CORP	0.059	0.059	0.053	0.053	0.893
DEERE & CO	0.135	0.135	0.211	0.211	0.413
KENNECOTT COPPER CORP	0.098	0.098	0.110	0.110	0.325
PHELPS DODGE CORP	0.134	0.134	0.162	0.162	0.472
IDEAL BASIC INDUSTRIES INC	0.123	0.128	0.156	0.166	0.882
LONE STAR INDUSTRIES	0.093	0.093	0.125	0.126	0.678
GENERAL PORTLAND INC	0.085	0.085	0.101	0.101	0.940
U S SHOE CORP	0.151	0.152	0.251	0.252	0.942
COMPO INDS	0.080	0.080	0.098	0.098	0.678
AVERAGE	0.122	0.122	0.171	0.173	0.664

T^2	Statistic Flow-through Utilities Vs. Medium Barrier Group	
	(1) All Return Measures Simultaneously	179.621√
	(2) Return Measures 3 & 4	7.169*
T	Statistic Return Measure 3	4.452*
T	Statistic Risk Level	5.766*
√	Significant at .01 Level	
*	Significant at .05 Level	

TABLE 6 (CONTINUED)

PART C

COMPARISON WITH HIGH BARRIER-TO-ENTRY GROUP (1967-1976)

Company Name	Return Measure 1	2	3	4	RISK
GENERAL MOTORS CORP	0.197	0.200	0.279	0.286	0.619
FORD MOTOR CO	0.111	0.113	0.165	0.170	0.576
CHRYSLER CORP	0.064	0.066	0.097	0.100	1.316
WRIGLEY (WILLIAM) JR CO	0.240	0.242	0.298	0.302	0.475
REYNOLDS (R.J.) INDS	0.253	0.258	0.363	0.373	0.468
AMERICAN BRANDS INC	0.158	0.158	0.270	0.272	0.516
LIGGETT GROUP	0.129	0.129	0.191	0.191	0.613
PHILIP MORRIS INC	0.166	0.172	0.330	0.359	0.273
MERCK & CO	0.349	0.358	0.472	0.492	0.264
PFIZER INC	0.169	0.174	0.250	0.264	0.211
SCHERING-PLOUGH	0.320	0.332	0.433	0.456	0.274
ABBOTT LABORATORIES	0.163	0.165	0.242	0.247	0.590
SEAGRAM CO LTD	0.101	0.102	0.134	0.135	0.565
NATIONAL DISTILLERS &CHEMICL	0.117	0.119	0.181	0.187	0.654
WALKER(HIRAM) GOODRHM & WORT	0.187	0.189	0.240	0.242	0.341
TEXASGULF INC	0.168	0.168	0.225	0.225	0.695
FREEPORT MINERALS CO	0.130	0.130	0.147	0.147	0.465
PPG INDUSTRIES INC	0.107	0.112	0.143	0.154	0.701
LIBBEY-OWENS-FORD CO	0.183	0.187	0.310	0.329	0.816
AVERAGE	0.174	0.178	0.251	0.260	0.549

T^2	Statistic Flow-through Utilities Vs. High Barrier Group	
	(1) All Return Measures Simultaneously	94.987√
	(2) Return Measures 3 & 4	38.675√
T	Statistic Return Measure 3	35.721√
T	Statistic Risk Level	0.467
√	Significant at .01 Level	

The rates of return on common shareholders' assets do not differ significantly. However, a significant difference occurs when all four profitability measures are analyzed at the same time, thereby implying that flow-through rates of return on total assets and on total productive assets are less than the related low barrier-to-entry rates of return.[50]

Alternatively, if .05 is the "proper" significance level, the rates of return for flow-through utilities are significantly lower in each statistical comparison. Flow-through companies' common shareholders are unable to achieve the same rate of return on their ownership claims as that earned by the residual equity holders of low barrier-to-entry firms. Since the comparison of normalized utilities with the low barrier-to-entry group does not permit such a statement (at any level of significance), flow-through accounting, with its stricter definition of recoverable income taxes, results in lower rates of return than does normalization.[51]

e. Flow-Through Utilities and Medium Barrier-to-Entry Companies

Part B of Table 6 reports the results of this comparison. They are identical to those obtained when flow-through firms are compared with the low barrier-to-entry group. The T^2 statistic from testing null hypothesis one is significant at the .01 level. Null hypotheses two and three are also rejected but only at the .05 level. Thus, the entire discussion of the preceding comparison could be repeated here.

f. Flow-Through Utilities and High Barrier-to-Entry Companies

Part C of Table 6 contains the detailed results of this comparison. The test statistics for all three null hypotheses are significant at the .01 level. In accord with the results of the earlier comparison involving the normalized utilities, the high barrier-to-entry group is able to achieve rates of return which significantly exceed those earned by the flow-through companies.

F. Summary

All profitability measures analyzed in this study are rates of return on assets. To promote comparability, reported after-tax net income is subjected to a few adjustments in deriving the four rate of return series. Adding back interest charges makes the rates of return on total assets and on total productive assets more congruent with regulatory practice. Adding back reported income taxes incorporates the differences between flow-through and normalized utilities. Removing the allowance for funds used during construction and construction work in progress permits the computation of rates of return on common shareholders' productive assets and on total productive assets, this study's closest approximation to the utility concept of rate of return on rate base. A residual claims/liquidation settlement approach forms the basis for determining rates of return on common shareholders' assets.

Whether or not utilities are able to earn above normal profits is assessed through rate of return comparisons with nonregulated companies. Oligopolistic in nature and leaders in their respective industries, the nonregulated companies are partitioned into three categories according to relative difficulty of entry, a surrogate for profit levels ranging from nearly monopolistic (the high barrier-to-entry group) to almost competitive (the set of low barrier-to-entry firms). The sample of nonregulated businesses is selected so as to coincide as closely as possible with companies analyzed in previous industrial concentration/barrier-to-entry research. Electric utilities with financial data available on the Utility COMPUSTAT tape form the sample of regulated firms. Average annual rates of return for the ten-year period 1967-76 constitute the data for the statistical comparisons.

Table 7 summarizes the results from testing a series of hypotheses which point toward four conclusions. First, there is no statistical evidence that utilities achieve the "monopolistic" rates of return of the high barrier-to-entry companies. Regulation removes the opportunity for monopoly profits. Second, utility rates of return on total assets

TABLE 7

SUMMARY OF TESTS PERFORMED IN SECTION III

Groups Compared	Hypothesis		
	U_1 Vs U_2	γ_1 Vs γ_2	ρ_1 Vs ρ_2
Normalized Electric Utilities Vs. High Barrier-to-Entry Companies	√	√	√
Normalized Electric Utilities Vs. Medium Barrier-to-Entry Companies	√	I	I
Normalized Electric Utilities Vs. Low Barrier-to-Entry Companies	√	I	I
Flow-Through Electric Utilities Vs. High Barrier-to-Entry Companies	√	√	√
Flow-Through Electric Utilities Vs. Medium Barrier-to-Entry Companies	√	*	*
Flow-Through Electric Utilities Vs. Low Barrier-to-Entry Companies	√	*	*

√ difference significant at .01 level
* difference significant at .05 level
I difference is not statistically significant at either .01 or .05 level

and on total productive assets are significantly lower than corresponding measures for the low barrier-to-entry group. This conclusion implies that regulation permits something close to a competitive rate of return on total productive assets (i.e., "rate base"). Third, at least for the normalized utilities (and, if the .05 significance level is unsatisfactory, for the flow-through utilities as well), rates of return on common shareholders' assets do not differ significantly from corresponding measures for both the low barrier and the medium barrier companies. One explanation for this result has already been offered. Utilities obtain higher than competitive earnings for their owners through financial leverage.[52] On the other hand, comparable levels of investor risk may explain the similarity between utility and nonutility rates of return on common shareholders' assets. This is examined in the next section. Finally, at the .05 significance level, flow-through utilities have lower rates of return on common stockholders' assets than do the medium barrier and the low barrier firms.

IV. RELAXING THE ASSUMPTIONS

A. Risk and Rates of Return

The preceding rate of return comparisons between regulated and non-regulated businesses are based on the assumption that no difference exists between the levels of risk borne by each group's owners. However, as discussed previously,[53] regulation may consider relative risk in the ratemaking process. In accord with the postulated relationship between risk and return, relative risk levels should be commensurate with anticipated profits. Rates of return on common shareholders' assets are the most appropriate profitability measures to contrast with the market-based estimates of investor risk used in this analysis. If regulation does incorporate risk, the lack of a significant difference between rates of return on common shareholders' assets for all utilities (or, with the .05 significance level, just for the normalized utilities) and for two of the three sets of nonregulated companies (i.e., low barrier and medium barrier firms) means that no significant investor risk level differences exist among these groups. If the results of an empirical test indicate that risk levels are indeed different, then the regulatory process either fails to consider risk or does so imperfectly. Further, the owners of the firms with lower investment are able to enjoy above normal profits--earnings which are "excessive" for the degree of risk they bear.

1. Measuring Risk

Risk is empirically estimated using the following equation:

$$R_{it} = \alpha_0 + \beta_i R_{mt};$$

where R_{it} = market based rate of return for company i in period t (Rate of return here is defined as the sum of period t's percentage change in price and dividend yield on the common stock of company i);

α_0 = the intercept term for the linear representation of the equation, the value of R_{it} when R_{mt} equals zero;

R_{mt} = rate of return on the market index in period t; and

B_i = relative risk measure for company i;

$$= \frac{\text{Covariance } (R_{it}, R_{mt})}{\text{Variance } (R_{mt})} .$$

Conceptually, to the investor β, or risk, reflects the variability in the rate of return of company i's stock in relation to the market. A high risk stock historically has higher rates of return than the market during "booms" and larger negative rates of return in "down" markets. Its rate of return fluctuates more widely than the "average" market rate of return. A stock whose return moves in exactly the same direction and in the same amount as the market return has an average β equal to one. High risk stocks are defined as those with β's above 1.2, and low risk are those whose β's are less than .8. "Average" risk is the most prevalent because the majority of stocks have β's between .8 and 1.2.[54] Listed in a separate column, the estimates of investor risk are presented by firm and for each group of firms in Tables 4, 5, and 6, and in the additional information provided in the Appendices.

2. Comparing Risk Levels

To determine the relationships between levels of investor risk for the five groups of companies analyzed in this study, a fourth set of hypotheses is tested for each of the comparisons performed in the preceding section:

H_0: $\beta_1 = \beta_2$; and

H_A: $\beta_1 \neq \beta_2$;

where β_1 = average investor risk estimated by the market model attributable to one of the five sets of companies; and

β_2 = average investor risk estimated by the market model attributable to a second set of companies.

Since the hypotheses involve a comparison of only one datum for each of the two groups of firms, the Student's T test is appropriate. Table 8 summarizes the test results, which, in terms of significant statistics, are completely converse to those obtained when rates of return on common shareholders' assets are similarly analyzed. When compared to the high barrier to entry group, utilities have no significant risk differences. However, their risk levels are significantly lower than those for the other two sets of nonregulated companies. With the flow-through utilities the .05 significance level must again be employed--this time in only one instance--to derive these results.

TABLE 8

STUDENT T STATISTICS FOR RISK COMPARISONS

Groups Compared	T Statistic
Normalized Utilities and Flow-Through Utilities	1.351
Normalized Utilities and Low Barrier-to-Entry Companies	33.523 √
Normalized Utilities and Medium Barrier-to-Entry Companies	19.919 √
Normalized Utilities and High Barrier-to-Entry Companies	3.536
Flow Through Utilities and Low Barrier-to-Entry Companies	10.529 √
Flow Through Utilities and Medium Barrier-to-Entry Companies	5.766*
Flow Through Utilities and High Barrier-to-Entry Companies	0.467

√ Significant at the .01 level
* Significant at the .05 level

3. <u>Using Risk as an Explanation of the Results of the Rate of Return Comparisons</u>

When the risk level and the rate of return comparisons are considered together, their combined results are consistent with the risk-return relationship in one case and inconsistent with it in two others. The situations where the conceptual relationship between risk and return is violated offer evidence that the regulatory process does not "appropriately" incorporate risk into rate-setting.

First, the comparisons between utilities and high barrier-to-entry companies provide results for the regulated firms in accord with the risk-return relationship. Even though risk levels do not differ (i.e., the risk associated with investment in utility stock is not significantly different from that existing for equity ownership in the most "monopolistic" firms analyzed in this report), rates of return on common shareholders' assets are significantly lower for the regulated companies than for the high barrier to entry group. Thus, regulation prevents monopoly profits by keeping rates of return more in line with the low levels of risk borne by utility investors.[55]

But the absence of monopoly rates of return does not ensure competitive or normal profits. The comparisons between normalized utilities (or, at the .01 significance level, all utilities) and the medium and low barrier-to-entry firms illustrate a situation which is not consistent with the risk-return relationship. Although investor risk for the utilities is significantly lower, the rates of return on common stockholders' assets are not significantly different. Thus, with regard to risk, regulation does not go far enough. For the level of risk borne by their owners, regulated businesses are able to earn "above normal" rates of return on shareholders' assets.

The second violation of the risk-return relationship arises solely within the utility sector. The two groups of regulated firms are analyzed separately because, per the first set of statistical tests, flow-through rates of return are significantly lower than normalized profitability measures. But this result cannot be justified on risk grounds since there is no significant difference in investor risk between the two sets of utility companies.

B. MARGINAL COST PRICING

None of the statistical evidence supports the existence of a marginal cost pricing policy in the regulated sector. With costs increasing throughout this study's ten-year period, pricing based on marginal cost would likely result in relatively high utility profit levels. The high rates of return on total assets and especially on total productive assets associated with such earnings are not reflected in the data. Regulation places its primary emphasis on preventing monopoly profits through average cost pricing. Besides adding new dimensions to the regulatory process, the advent of marginal cost pricing would probably cause substantial changes in the pre-tax rate of return relationships between regulated and nonregulated firms.

C. Rate Base Inflation

As mentioned earlier,[56] rate base inflation is unobservable with the rates of return computed in this study. If it exists due to regulator unwillingness to permit an increase in the utility's allowable rate of return, profitability measures for shareholders' productive assets are either overstated (if the rate base increase is financed through additional borrowing) or understated (if no increase in borrowing occurs, as when a cost-of-service expenditure is capitalized). If it is truly a substitute for successfully securing a higher allowable rate of return, rate base inflation understates profitability measures on total productive assets. To assess rate base inflation, research must focus directly on the rate base, not on rates of return.

Reliance must be placed on the regulatory authority for the prevention of rate base inflation. However, the political nature of the rate-making process raises questions concerning the wisdom of such reliance. The fact that a utility can augment its total profits by increasing either its allowable rate of return or its rate base is obvious but by no means trivial. The self-interest of both the utility and its regulator may best be served by higher aggregate earnings through rate base increases. Neither side in the regulatory process has much motivation for attempting to raise the utility's allowable rate of return. Increasing the base is much easier, less observable and consequently less susceptible to public criticism. Of course, even if tacitly approved by the regulator, rate base inflation creates distortions in utility rate of return data, thereby weakening the validity of this report's statistical comparisons.

D. Summary

Although investor risk may be a factor in the determination of a utility's allowable rate of return, regulation does not force profitability measures on common shareholders' assets to be commensurate with the low risk levels borne by the utility's owners. Monopoly profits are prevented but above normal profits (i.e., rates of return equivalent to those attainable in the nonregulated sector only by accepting a higher degree of risk) do exist. Large amounts of financial leverage (made possible at least in part by the absence of substantial amounts of risk) permit utilities to achieve such profit levels for their stockholders.

The rate of return data in this study offer no discernable evidence that utilities practice marginal cost pricing.

Research is needed to identify and measure rate base inflation. The effects of this tactic to increase total profits, if it does exist, are impounded in the utility rate of return data. Thus, regardless of whether or not it receives regulator approval, a substantial amount of rate base inflation would likely alter some of this study's conclusions.

V. RATES OF RETURN BY REGULATORY JURISDICTION

A. Comparisons Solely Within the Regulated Sector

Using the utility profitability measures already discussed as well as those for another group of regulated companies (the airline industry), this section attempts to discern the impact of differing regulatory practices on rates of return. One such comparison (i.e., "Normalized" states and "Flow-Through" states) has already been performed. A further breakdown of utilities into a state-by-state grouping is also presented. Even though state sovereignty prevails, these types of analyses may be useful to federal officials seeking some degree of national uniformity in the regulatory process. In addition, a state commission is able to determine "where it stands" in relation to its counterparts throughout the country. Finally, the utilities are compared with a sample of firms from the airline industry. Here the analysis crosses not only jurisdictional boundaries but also levels of government and market structures (since the federally regulated airlines operate in a much more competitive environment than the public utilities). In all cases, rates of return are determined in exactly the same manner as described in Section III.

1. "Normalized" States and "Flow-Through" States

The numerical results of this comparison are found elsewhere in this report.[57] Although risk levels are not significantly different, rates of return for normalized companies are higher than those for flow-through utilities. Thus, regulation in flow-through states generally is "stricter" than that existing in normalized jurisdictions.

2. State-by-State

Appendix 5 arrays the sample of electric utilities on a state-by-state basis. Companies subject to regulation in more than one state are listed at the end of the appendix. In many cases a state is represented by only one utility. Thus, the data are provided strictly for information purposes. An expanded sample of regulated businesses is needed to perform any statistical comparisons by state.

3. Electric Utilities and Airlines

Tables 9 and 10 present the comparisons between airlines and normalized utilities and flow-through utilities respectively. The results of the two sets of statistical tests are similar. The utilities have significantly lower risk levels and significantly higher (at the .01 level) rates of return.

At least two explanations exist for the relatively low profitability measures and the high amounts of investor risk existing in the airline industry. First, the federal government may be a much more stringent regulator than the state commissions. Second, intense competition, rather than federal regulation, may cause the airlines' financial results. Regardless of which explanation is "correct," the statistical comparisons offer additional evidence for two of the previous conclusions. Utilities are able to achieve profit levels which are both higher than those in more competitive industries and "excessive" for the level of risk borne by their owners.

B. Summary

The comparisons discussed in this section illustrate three ways in which the rate of return data for regulated businesses can be analyzed. As demonstrated previously, utilities fare better in normalized states than in flow-through jurisdictions. Electric companies also compare very favorably with airlines, thereby offering further support for the conclusion that utility regulation by the state commissions does not result in perfectly competitive profit levels. Additional statistical comparisons of utility rates of return by state are not performed in this study because of data limitations. Instead, a state-by-state grouping of profitability measures is presented for information purposes.

TABLE 9

COMPARISON OF RISK AND RETURNS FOR NORMALIZED ELECTRIC UTILITIES AND AIRLINES (1967-1976)

Electric Utility	Return Measure 1	2	3	4	RISK
AMERICAN ELECTRIC POWER	0.083	0.076	0.135	0.131	0.516
ATLANTIC CITY ELECTRIC	0.085	0.081	0.157	0.182	0.555
BANGOR HYDRO-ELEC CO	0.079	0.078	0.149	0.147	0.524
BLACK HILLS POWER & LIGHT CO	0.092	0.094	0.155	0.191	0.428
BOSTON EDISON CO	0.084	0.075	0.123	0.102	0.525
BRASCAN LTD-CL A	0.078	0.073	0.073	0.065	0.614
CAROLINA POWER & LIGHT	0.091	0.086	0.151	0.189	0.609
CENTRAL & SOUTH WEST CORP	0.121	0.122	0.211	0.222	0.398
CENTRAL MAINE POWER CO	0.090	0.090	0.160	0.164	0.310
CLEVELAND ELECTRIC ILLUM	0.103	0.101	0.183	0.503	0.384
COMMONWEALTH EDISON	0.096	0.091	0.168	0.168	0.307
COMMUNITY PUBLIC SERVICE	0.099	0.099	0.177	0.176	0.435
DETROIT EDISON CO	0.078	0.072	0.118	0.102	0.714
DUKE POWER CO	0.088	0.080	0.148	0.160	0.612
DUQUESNE LIGHT CO	0.092	0.089	0.169	0.197	0.504
EASTERN UTILITIES ASSOC	0.086	0.085	0.139	0.226	0.761
EDISON SAULT ELECTRIC	0.095	0.094	0.169	0.168	~~0.9~~
EL PASO ELECTRIC CO	0.121	0.120	0.220	0.232	0.358
EMPIRE DISTRICT ELECTRIC CO	0.102	0.099	0.180	0.174	0.326
FLORIDA POWER & LIGHT	0.106	0.105	0.175	0.236	0.575
FLORIDA POWER CORP	0.099	0.096	0.170	0.212	0.636
GENERAL PUBLIC UTILITIES	0.076	0.071	0.112	0.123	0.629
GULF STATES UTILITIES CO	0.099	0.096	0.181	0.203	0.484
HAWAIIAN ELECTRIC CO	0.091	0.088	0.146	0.143	0.477
IDAHO POWER CO	0.088	0.086	0.151	0.153	0.363
INDIANAPOLIS POWER & LIGHT	0.105	0.103	0.207	0.267	0.694
KANSAS CITY POWER & LIGHT	0.090	0.089	0.159	0.167	0.481
KANSAS GAS & ELECTRIC	0.103	0.100	0.190	0.284	0.558
KENTUCKY UTILITIES CO	0.105	0.104	0.169	0.180	0.465
MAINE PUBLIC SERVICE	0.091	0.090	0.158	0.155	0.491
MIDDLE SOUTH UTILITIES	0.092	0.089	0.163	0.195	0.417
MINNESOTA POWER & LIGHT	0.089	0.086	0.174	0.169	0.390
NEW ENGLAND ELECTRIC SYSTEM	0.083	0.080	0.150	0.146	0.533
OKLAHOMA GAS & ELECTRIC	0.110	0.110	0.216	0.239	0.342
OTTER TAIL POWER CO	0.093	0.096	0.174	0.614	0.281
POTOMAC ELECTRIC POWER	0.076	0.081	0.120	0.168	0.460
PUBLIC SERVICE CO OF IND	0.112	0.113	0.203	0.233	0.423
PUBLIC SERVICE CO OF N MEX	0.103	0.103	0.180	0.201	0.592
SAVANNAH ELEC & POWER	0.085	0.082	0.132	0.144	0.537
SOUTHERN CO	0.089	0.086	0.146	0.191	0.504
SOUTHWESTERN ELEC SERVICE	0.097	0.096	0.203	0.202	0.371
SOUTHWESTERN PUBLIC SERV CO	0.109	0.109	0.226	0.248	0.374
TAMPA ELECTRIC CO	0.097	0.094	0.174	0.182	0.773
TEXAS UTILITIES CO	0.120	0.120	0.229	0.261	0.199
TOLEDO EDISON COMPANY	0.096	0.098	0.199	0.228	0.418
UNION ELECTRIC CO	0.080	0.077	0.140	0.150	0.400
UPPER PENINSULA POWER	0.085	0.084	0.147	0.146	0.440
UTAH POWER & LIGHT	0.081	0.080	0.135	0.145	0.344
VIRGINIA ELECTRIC & POWER	0.085	0.077	0.135	0.175	0.617

TABLE 9 (CONTINUED)

Electric Utility	Return Measure				
BALTIMORE GAS & ELECTRIC	0.096	0.094	0.175	0.368	0.420
CENTRAL ILLINOIS LIGHT	0.095	0.094	0.165	0.201	0.487
CENTRAL ILL PUBLIC SERVICE	0.101	0.100	0.189	0.203	0.567
CONSUMERS POWER CO	0.085	0.081	0.137	0.136	0.711
FITCHBURG GAS & ELEC LIGHT	0.083	0.082	0.119	0.117	0.387
ILLINOIS POWER CO	0.108	0.106	0.205	0.209	0.497
INTERSTATE POWER CO	0.089	0.089	0.190	0.239	0.436
IOWA ELECTRIC LIGHT & PWR	0.084	0.078	0.140	0.118	0.713
IOWA-ILLINOIS GAS & ELEC	0.100	0.094	0.180	0.169	0.734
IOWA POWER & LIGHT	0.092	0.092	0.177	0.191	0.353
IOWA PUBLIC SERVICE CO	0.098	0.095	0.175	0.178	0.304
IOWA SOUTHERN UTILITIES CO	0.118	0.118	0.206	0.217	0.571
KANSAS POWER & LIGHT	0.108	0.107	0.187	0.192	0.281
LAKE SUPERIOR DIST POWER CO	0.085	0.086	0.153	0.160	0.315
LOUISVILLE GAS & ELECTRIC	0.120	0.125	0.216	0.244	0.436
MADISON GAS & ELECTRIC CO	0.088	0.086	0.141	0.207	0.367
MISSOURI PUBLIC SERVICE CO	0.090	0.086	0.187	0.171	0.631
MONTANA POWER CO	0.111	0.111	0.179	0.184	0.311
NEW ENGLAND GAS & ELECTRIC	0.087	0.085	0.146	0.147	0.529
NORTHERN INDIANA PUBLIC SERV	0.106	0.105	0.203	0.225	0.337
NORTHERN STATES POWER	0.093	0.087	0.132	0.184	0.477
NORTHWESTERN PUBLIC SERV CO	0.093	0.093	0.169	0.337	0.392
PHILADELPHIA ELECTRIC CO	0.085	0.081	0.135	0.180	0.428
PUBLIC SERVICE CO OF COLO	0.080	0.077	0.142	0.146	0.265
PUBLIC SERVICE ELEC & GAS	0.079	0.075	0.125	0.136	0.609
ST JOSEPH LIGHT & POWER	0.095	0.094	0.179	0.187	0.599
SIERRA PACIFIC POWER CO	0.079	0.076	0.120	0.116	0.502
SOUTH CAROLINA ELEC & GAS	0.088	0.085	0.145	0.163	0.841
SOUTHERN INDIANA GAS & ELEC	0.120	0.117	0.220	0.215	0.445
WISCONSIN ELECTRIC POWER	0.100	0.099	0.185	0.185	0.140
WISCONSIN POWER & LIGHT	0.108	0.108	0.209	0.236	0.419
WISCONSIN PUBLIC SERVICE	0.106	0.105	0.210	0.232	0.291
MONTANA-DAKOTA UTILITIES	0.092	0.090	0.156	0.150	0.262
AVERAGE	0.095	0.093	0.167	0.195	0.473

TABLE 9 (CONTINUED)

Airlines	Return Measure 1	2	3	4	RISK
ALLEGHENY AIRLINES INC	0.044	0.044	-0.051	-0.051	1.564
AMERICAN AIRLINES INC	0.032	0.032	0.030	0.030	1.196
BRANIFF INTL CORP	0.080	0.080	0.130	0.132	1.276
CAPITOL INTL AIRWAYS	0.072	0.072	0.092	0.092	1.599
CONTINENTAL AIR LINES INC	0.060	0.061	0.064	0.064	1.511
DELTA AIR LINES INC	0.147	0.148	0.211	0.214	0.726
EASTERN AIR LINES	0.039	0.039	0.004	0.003	1.587
HAWAIIAN AIRLINES INC	0.061	0.062	0.062	0.063	0.626
KLM ROYAL DUTCH AIRLINES	0.038	0.038	0.022	0.022	0.997
NATIONAL AIRLINES INC	0.092	0.093	0.130	0.133	1.415
NORTH CENTRAL AIRLINES INC	0.084	0.084	0.110	0.108	1.210
NORTHWEST AIRLINES INC	0.100	0.100	0.131	0.133	1.113
OVERSEAS NATIONAL AIRWAYS	0.032	0.032	0.019	0.019	0.328
OZARK AIR LINES INC	0.062	0.062	0.061	0.061	0.985
PSA INC	0.064	0.064	0.070	0.070	1.394
PAN AMERICAN WORLD AIRWAYS	0.017	0.017	-0.068	-0.076	1.503
PIEDMONT AVIATION INC	0.063	0.063	0.091	0.091	1.731
SEABOARD WORLD AIRLINES	0.057	0.057	0.059	0.059	1.469
TIGER INTERNATIONAL	0.091	0.091	0.151	0.153	1.050
TRANS WORLD AIRLINES	0.032	0.032	0.008	0.007	1.597
UAL INC	0.054	0.054	0.072	0.072	0.940
WESTERN AIR LINES INC	0.071	0.072	0.090	0.092	1.238
WIEN AIR ALASKA	0.076	0.077	0.101	0.105	0.617
WORLD AIRWAYS INC	0.071	0.071	0.124	0.124	1.428
AVERAGE	0.065	0.065	0.066	0.066	1.184

T^2	Statistic Normalized Utilities Vs. Airlines	
	(1) All Return Measures Simultaneously	143.457 √
	(2) Return Measures 3 & 4	31.188 √
T	Statistic Return Measure 3	27.567 √
T	Statistic Risk Level	160.887 √
√	Significant at the .01 Level	

TABLE 10

COMPARISON OF RISK AND RETURN FOR FLOW-THROUGH ELECTRIC UTILITIES AND AIRLINES

Electric Utility	Return Measure 1	2	3	4	RISK
ALLEGHENY POWER SYSTEM	0.093	0.089	0.170	0.164	0.525
CENTRAL VERMONT PUB SERV	0.067	0.063	0.093	0.083	0.766
COLUMBUS & SOUTHERN OHIO	0.085	0.082	0.143	0.225	0.693
CONCORD ELECTRIC CO	0.083	0.082	0.140	0.139	~~0.0~~
GREEN MOUNTAIN POWER CORP	0.073	0.067	0.114	0.096	1.063
NEVADA POWER CO	0.085	0.080	0.127	0.129	0.650
NORTHEAST UTILITIES	0.076	0.069	0.120	0.108	0.582
OHIO EDISON CO	0.099	0.096	0.172	0.206	0.432
PENNSYLVANIA POWER & LIGHT	0.086	0.082	0.159	0.199	0.441
PORTLAND GENERAL ELECTRIC CO	0.086	0.086	0.131	0.187	0.444
PUBLIC SERVICE CO OF N H	0.083	0.080	0.146	0.144	0.564
PUGET SOUND POWER & LIGHT	0.073	0.072	0.113	0.126	0.476
SOUTHERN CALIF EDISON CO	0.078	0.077	0.129	0.133	0.382
UNITED ILLUMINATING CO	0.082	0.080	0.156	0.394	0.412
ARIZONA PUBLIC SERVICE CO	0.075	0.075	0.125	0.166	0.491
CENTRAL HUDSON GAS & ELEC	0.080	0.077	0.143	0.138	0.480
CINCINNATI GAS & ELECTRIC	0.101	0.097	0.193	0.200	0.284
CONSOLIDATED EDISON OF N.Y.	0.064	0.061	0.093	0.088	0.802
DAYTON POWER & LIGHT	0.092	0.088	0.171	0.178	0.479
DELMARVA POWER & LIGHT	0.085	0.079	0.143	0.134	0.472
LONG ISLAND LIGHTING	0.085	0.084	0.156	0.187	0.530
NEW YORK STATE ELEC & GAS	0.078	0.076	0.131	0.140	0.534
NIAGARA MOHAWK POWER	0.068	0.064	0.109	0.107	0.490
ORANGE & ROCKLAND UTILITIES	0.076	0.073	0.128	0.119	0.637
PACIFIC GAS & ELECTRIC	0.080	0.078	0.133	0.132	0.240
PACIFIC POWER & LIGHT	0.074	0.070	0.117	0.115	0.487
ROCHESTER GAS & ELECTRIC	0.077	0.075	0.126	0.122	0.606
SAN DIEGO GAS & ELECTRIC	0.079	0.078	0.124	0.127	0.511
TUCSON GAS & ELECTRIC	0.090	0.087	0.152	0.155	0.532
WASHINGTON WATER POWER	0.083	0.081	0.147	0.145	0.282
AVERAGE	0.081	0.078	0.137	0.153	0.527

TABLE 10 (CONTINUED)

Airlines	Return Measure 1	2	3	4	RISK
ALLEGHENY AIRLINES INC	0.044	0.044	-0.051	-0.051	1.564
AMERICAN AIRLINES INC	0.032	0.032	0.030	0.030	1.196
BRANIFF INTL CORP	0.080	0.080	0.130	0.132	1.276
CAPITOL INTL AIRWAYS	0.072	0.072	0.092	0.092	1.599
CONTINENTAL AIR LINES INC	0.060	0.061	0.064	0.064	1.511
DELTA AIR LINES INC	0.147	0.148	0.211	0.214	0.726
EASTERN AIR LINES	0.039	0.039	0.004	0.003	1.587
HAWAIIAN AIRLINES INC	0.061	0.062	0.062	0.063	0.626
KLM ROYAL DUTCH AIRLINES	0.038	0.038	0.022	0.022	0.997
NATIONAL AIRLINES INC	0.092	0.093	0.130	0.133	1.415
NORTH CENTRAL AIRLINES INC	0.084	0.084	0.110	0.108	1.210
NORTHWEST AIRLINES INC	0.100	0.100	0.131	0.133	1.113
OVERSEAS NATIONAL AIRWAYS	0.032	0.032	0.019	0.019	0.328
OZARK AIR LINES INC	0.062	0.062	0.061	0.061	0.985
PSA INC	0.064	0.064	0.070	0.070	1.394
PAN AMERICAN WORLD AIRWAYS	0.017	0.017	-0.068	-0.076	1.503
PIEDMONT AVIATION INC	0.063	0.063	0.091	0.091	1.731
SEABOARD WORLD AIRLINES	0.057	0.057	0.059	0.059	1.469
TIGER INTERNATIONAL	0.091	0.091	0.151	0.153	1.050
TRANS WORLD AIRLINES	0.032	0.032	0.008	0.007	1.597
UAL INC	0.054	0.054	0.072	0.072	0.940
WESTERN AIR LINES INC	0.071	0.072	0.090	0.092	1.233
WIEN AIR ALASKA	0.076	0.077	0.101	0.105	0.617
WORLD AIRWAYS INC	0.071	0.071	0.124	0.124	1.423
AVERAGE	0.065	0.065	0.066	0.066	1.12[illegible]

T^2	Statistic Flow-through Utilities Vs. Airlines	
	(1) All Return Measures Simultaneously	107.878√
	(2) Return Measures 3 & 4	29.956√
T	Statistic Return Measure 3	28.847√
T	Statistic Risk Level	58.328√
√	Significant at .01 Level	

FOOTNOTES

1. Additional complications exist for those public utilities which capitalize interest on funds used during construction. See Section III, Part A, for a complete discussion.

2. In an opportunity cost context, "normal profit" is the amount foregone by not pursuing the best available alternate course of action.

3. Much of this discussion can be drawn from any microeconomic treatment of regulation. See, for example, Jack Hirshleifer, Price Theory and Applications (Englewood Cliffs, N.J.: Prentice-Hall, 1976), pp. 288-290.

4. The estimation of demand plays a critical role in the rate-setting process. If it is underestimated, the utility will recover its original projected amounts for cost-of-service and allowable profit. But, in an increasing cost situation, the excess revenues generated by the difference between actual and expected demand will fall short of the rise in costs, thereby necessitating a rate increase to achieve normal profit.

   If demand is overestimated, the utility will not recover the total of its cost of service and allowable profit. To the extent that they are variable, some costs will be lower than projected (due to smaller output). But in all likelihood, since many of its costs are fixed, the utility will be forced to seek a rate increase to arrive at normal profit. Hence, a regulatory anomaly is that overly effective energy conservation causing lower demand than anticipated pushes rates up even more.

5. See the following discussion of the risk-return relationship.

6. Thus, some evidence may be found that at least for this attribute, a regulated public utility is able to retain a characteristic of an unregulated monopolist. See footnote 10.

7. For the 113 electric utilities analyzed in this report, the average (unweighted mean) ratio of total long-term debt to total equity is .43. The same statistic for the 73 unregulated firms is .19.

8. See Irwin Friend and James L. Bicksler (eds.), Risk and Return in Finance, Volumes I and II (Cambridge, Mass.: Ballinger Publishing Company, 1977).

9. Of course, utility investments would not be very "risky" even in the absence of regulation. See footnote 10.

10. One exception to the risk-return relationship occurs for an unregulated monopoly (or for the firms in an oligopolistic industry with substantial entry barriers). Although the risk level is very low, profits may still be high. The lack of competition in the product market provides the investor with the opportunity to enjoy a high rate of return while bearing only a minimal amount of risk. Regulation's function in this context can be viewed as reducing the rate of return so as to make it "appropriate" for the level of risk assumed.

11. Because a single price or rate usually prevails in a market, a consumer is able to reap a "surplus" on all those units purchased whose incremental value exceeds price. The last unit bought will have its marginal value equal to price.

12. When the demand curve intersects the average total cost curve at its low point.

13. Hirshleifer, op. cit. The analysis points in a different direction if the utility is confronted with continually decreasing average total cost as output expands.

14. The principal policy trade-off between these two alternatives is apparent. Optimal resource allocation with marginal cost pricing enables a utility to enjoy an "above normal profit." In Figure 1 this amounts to the area of R_1R_3CD. In accord with President Carter's proposal which accompanies the deregulation of oil prices, an excess profits tax could be applied to a public utility practicing marginal cost pricing.

15. Only in the perfectly competitive model do marginal cost pricing and average cost pricing have identical results.

16. Of course, if utility rates of return (especially on total assets and on total productive assets) are substantially below corresponding measures in each of the industrial groups, strong (but not conclusive) evidence would exist that utilities employ average cost pricing.

17. The concept of marginal cost pricing may be difficult to operationalize in a rate-making setting. A substitute such as "replacement cost pricing" may be easier to implement in a practical situation.

18. H. Averch, and L.L. Johnson, "Behavior of the Firm Under Regulatory Constraint, "The American Economic Review, Vol. 52, No. 5 (December 1962), pp. 1053-1069.

19. See, for example, W.J. Baumol and A.K. Klevorick, "Input Choices and Rate of Return Regulation: An Overview of the Discussion," The Bell Journal of Economics and Management Science, Vol. 1, No.2 (Autumn 1970), pp. 162-190; Courville, L., "Regulation and Efficiency in the Electric Utility Industry," The Bell Journal of Economics and Management Science, Vol. 5, No. 1 (Spring 1974), pp. 53-74; and Spann, R.M., "Rate of Return Regulation and Efficiency in Production: An Empirical Test of the Averch-Johnson Thesis," The Bell Journal of Economics and Management Science, Vol. 5, No. 1 (Spring 1974), pp. 38-52.

20. Besides including resources that the utility will never really need, "unnecessary" is also given a time dimension here. A temporary, more subtle form of rate base inflation occurs whenever a utility acquires assets which, although needed at some future date, end up included in the rate base prior to that time. Obviously, some value judgments are required to resolve this issue in the regulatory setting. The competitive nature of their environment (and the fact that, unlike utilities, they are not able to earn a return on "unnecessary" assets) virtually precludes this type of behavior for most nonregulated firms.

21. See the previous discussion of the effects of financial leverage, pages 9-10.

22. See the example in the next section.

23 Utility B may still be concerned about the advisability of this strategy because of lower dividend distributions in Years 1, 2, and 3 (i.e., during the period when most of the rate base inflation occurs). To overcome this, an obvious tactic would be short-term borrowing to pay dividends. Although the interest on such debt would slightly reduce the total return to shareholders for a few years, the need to borrow for dividend payments would likely evoke public sympathy for the utility's financial plight and constitute further evidence that its profits are not excessive.

24. The problem, of course, is the inability to distinguish Situation 3 from Situation 1 and Situation 4 from Situation 2. Although its effects are impounded in the reported financial data, rate base inflation is essentially unobservable in this study's profitability measures.

25. See footnote 7.

26. In this case the "inefficiency" which inflates the rate base is strictly an accounting phenomenon.

27. See page 5.

28. For an in-depth treatment of normalization and flow-through, see D.W. Kiefer, "Accelerated Depreciation and the Investment Tax Credit in the Public Utility Industry: A Background Analysis," (Columbus, Ohio: National Regulatory Research Institute, 1979).

29. Accounting Principles Board, "Accounting for Income Taxes," Opinion Number 11 (New York: American Institute of Certified Public Accountants, Inc., 1967).

30. A provision in the Revenue Act of 1971 stipulates that no taxpayer is required to use any particular method of accounting for the investment tax credit in reports subject to the jurisdiction of any federal agency. Rules regarding the accounting for the credit by public utilities contain additional complications. See Kiefer, op. cit.

31. Here the transformation of F into a normalized utility stops with the adjustment to income tax expense. However, if F were truly subject to normalization, the dynamics of the rate-setting process would likely continue. With taxes at $10.5 the results indicate that regulation did not permit F to earn its allowable return on rate base. Accordingly, F would seek some sort of "emergency" rate increase. A $15 increase in revenue would, after the application of the 50% tax, bring F's reported operating income back up to $30, thus allowing F to achieve reported results identical to N.

32. The data in the example can illustrate a potential incongruous result from flow-through accounting. Since Company F cannot "keep" any of the tax savings, it has little motivation for using accelerated depreciation on its tax return. Thus, it switches to the straight-line method, thereby increasing current tax expense and revenue requirements by $15. F's income statement is now exactly the same as N's. Both companies have the same rate of return measures. N still has the advantage of deferring $7.5 of its income taxes while F must pay the full $18 currently. The switch to straight-line depreciation for tax purposes simply makes F's customers pay $15 more to the utility which it then remits to the Internal Revenue Service. Utility F's action would undoubtedly be censured by its Regulatory Authority.

33. See pages 5-6.

34. For an in-depth treatment of this issue, see Lawrence S. Pomerantz and James E. Suelflow, Allowance for Funds Used During Construction (East Lansing, Michigan: Michigan State University Institute of Public Utilities, 1975).

35. This treatment of AFUDC has two favorable results. First, once the CWIP is placed in operation, capitalized AFUDC is recoverable as depreciation over the asset's useful life. Although not increasing profits, this augments cash flow and permits, contrary to the typical rate-making process, recovery of interest and "earnings" on equity funds as part of cost-of-service.

    Second, AFUDC allows the rate base to exceed actual out-of-pocket costs, thereby increasing total profits. This is another example of "rate base inflation" discussed earlier to the extent that the total amount placed in the rate base exceeds the price which the utility would have paid to acquire a similar asset, fully constructed and financed (prior to its completion) with nonutility funds.

36. The "shareholders" on whose assets rates of return are calculated are defined as the owners of the majority interests of the corporations analyzed in this study. Accordingly, an adjustment not discussed in the body of the report is the removal from all consolidated financial statements of the income and assets attributed to any minority interest.

37. Another way of deriving rates of return on common shareholders' productive assets is based on the assumption (perhaps more congruent with the regulatory environment) that each class of utility creditor and owner has a claim on CWIP in proportion to its share of total capitalization. Thus, starting with the rate of return on total common shareholders' assets, AFUDC would be entirely removed from the numerator but only a portion of CWIP (based on the ratio of common equity to total capitalization) would be subtracted from the denominator. Included as a fifth rate of return series for utilities in Table 4, this set of profitability measures has lower values than the rates of return on common shareholders' productive assets used in the statistical tests discussed later in this report.

38. The alternative approach to Measure 4 discussed in footnote 37 is expressed as:

$$R4'_{it} = \frac{I_{it} + T_{it} - PD_{it} - AFUDC_{it}}{TA_{it} - LIQPF_{it} - LTD_{it} - CL_{it} - \left(\frac{CEQ_{it}}{CAP_{it}}\right) CWIP_{it}}$$

where

CEQ_{it} = Average common shareholders' equity;

CAP_{it} = Average total capitalization; and all the other variables are defined as in the text.

$R4'_{it}$ = Alternative Accounting Rate of Return on Common Shareholders' Productive Assets

Since $CAP_{it} > CEQ_{it}$, $R4_{it} > R4'_{it}$.

39. See H. Michael Mann, "Seller Concentration, Barriers to Entry, and Rates of Return in Thirty Industries, 1950-60," Review of Economics and Statistics, 48 (August, 1966), pp. 296-307, and Timothy L. Sullivan, "Market Power, Profitability, and Financial Leverage," The Journal of Finance, 29 (December, 1974) pp. 1407-1414.

40. The COMPUSTAT tape is a magnetic computer tape service offered by Standard and Poor's. Providing additional information for regulated companies, the Utility COMPUSTAT also contains most of the data items reported to the Securities and Exchange Commission.

41. Mann, op. cit., pp. 306-307.

42. Sullivan, op cit., pp. 1408-1409.

43. In a very few instances obvious outliers were removed, thereby creating eight or nine-year averages for some companies. These occur in the computation of Measure 4 where the subtraction of CWIP makes the denominator very small (causing the annual rate of return to exceed 100%) or slightly negative (making the return measure a very large negative number).

44. See page 21.

45. See pages 22-24.

46. See the numerical example on page 23.

47. For a full explanation of Hotelling T^2 test, see Bolch, Ben W. and Cliff J. Huang, Multivariate Statistical Methods for Business and Economics (Prentice Hall; International Series in Management, Englewood Cliffs, New Jersey, 1974)

48. C.E. Weatherburn, A First Course in Mathematical Statistics (Cambridge University Press, London, 1968)

49. This conclusion is confirmed in a separate T^2 test involving vectors comprised of the rates of return on total assets and on total productive assets (i.e., Measures 1 and 2). The null hypothesis is rejected at the .01 level.

50. Using data for flow-through rather than normalized utilities, the test described in footnote 49 also results in rejection of the null hypothesis at the .01 level.

51. The previous comparison involving flow-through and normalized utilities also reflects this. See pages 31-35 and Table 4.

52. See pages 9-10.

53. See pages 10-11.

54. A listing of risk measures in large U.S. firms may be found in Security Risk Evaluation (Merril, Lynch, Pierce Fenner & Smith, New York, August 1978).

55. See footnote 10.

56. See pages 12-18.

57. See pages 31-35.

APPENDIX 1

Ten-Year Returns for All Electric Utilities In Study

TABLE NO. 1.1

RATE OF RETURN MEASURE 1

A11

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
ALLEGHENY POWER SYSTEM	0.525	0.098	0.095	0.088	0.086	0.083	0.091	0.090	0.080	0.103	0.110	0.093
AMERICAN ELECTRIC POWER	0.516	0.091	0.090	0.084	0.081	0.077	0.075	0.080	0.077	0.084	0.091	0.083
ATLANTIC CITY ELECTRIC	0.555	0.086	0.087	0.083	0.076	0.072	0.085	0.082	0.082	0.096	0.100	0.085
BANGOR HYDRO-ELEC CC	0.524	0.102	0.095	0.087	0.078	0.066	0.085	0.061	0.069	0.089	0.064	0.079
BLACK HILLS POWER & LIGHT CO	0.428	0.083	0.084	0.081	0.077	0.098	0.102	0.104	0.099	0.101	0.091	0.092
BOSTON EDISON CC	0.525	0.093	0.093	0.089	0.078	0.075	0.069	0.073	0.084	0.089	0.091	0.084
BRASCAN LTD-CL A	0.614	0.072	0.072	0.072	0.074	0.085	0.092	0.100	0.084	0.069	0.066	0.078
CAROLINA POWER & LIGHT	0.609	0.096	0.099	0.091	0.066	0.078	0.099	0.082	0.075	0.102	0.118	0.091
CENTRAL & SOUTH WEST CORP	0.388	0.117	0.123	0.129	0.123	0.119	0.125	0.125	0.120	0.117	0.110	0.121
CENTRAL MAINE POWER CC	0.310	0.098	0.096	0.091	0.094	0.084	0.096	0.090	0.077	0.084	0.093	0.090
CENTRAL VERMONT PLE SERV	0.766	0.076	0.070	0.067	0.062	0.051	0.064	0.032	0.064	0.091	0.091	0.067
CLEVELAND ELECTRIC ILLUM	0.384	0.128	0.129	0.117	0.103	0.097	0.093	0.086	0.096	0.088	0.092	0.103
COLUMBUS & SOUTHERN OHIO	0.603	0.101	0.097	0.090	0.077	0.069	0.076	0.081	0.063	0.101	0.083	0.085
COMMONWEALTH EDISON	0.307	0.114	0.113	0.102	0.091	0.084	0.090	0.092	0.085	0.092	0.094	0.096
COMMUNITY PUBLIC SERVICE	0.435	0.085	0.089	0.097	0.102	0.104	0.109	0.107	0.096	0.096	0.107	0.099
CONCORD ELECTRIC CC	0.000	0.064	0.080	0.077	0.076	0.075	0.094	0.073	0.087	0.110	0.106	0.083
DETROIT EDISON CO	0.714	0.091	0.087	0.085	0.073	0.072	0.079	0.076	0.072	0.074	0.076	0.076
DUKE POWER CO	0.612	0.108	0.105	0.094	0.066	0.071	0.069	0.077	0.085	0.098	0.111	0.088
DUQUESNE LIGHT CO	0.504	0.105	0.102	0.093	0.082	0.091	0.089	0.086	0.086	0.097	0.088	0.092
EASTERN UTILITIES ASSCC	0.761	0.106	0.097	0.083	0.078	0.086	0.086	0.058	0.085	0.080	0.097	0.086
EDISON SAULT ELECTRIC	0.000	0.114	0.114	0.101	0.090	0.078	0.080	0.094	0.108	0.088	0.082	0.095
EL PASO ELECTRIC CC	0.358	0.125	0.130	0.133	0.127	0.122	0.125	0.118	0.108	0.107	0.113	0.121
EMPIRE DISTRICT ELECTRIC CO	0.326	0.111	0.115	0.104	0.109	0.097	0.094	0.094	0.094	0.098	0.102	0.102
FLORIDA POWER & LIGHT	0.575	0.110	0.116	0.114	0.103	0.108	0.099	0.105	0.091	0.116	0.094	0.106
FLORIDA POWER CORP	0.636	0.103	0.108	0.110	0.102	0.095	0.100	0.090	0.075	0.103	0.100	0.099
GENERAL PUBLIC UTILITIES	0.629	0.075	0.072	0.062	0.058	0.069	0.078	0.078	0.084	0.087	0.099	0.076
GREEN MOUNTAIN POWER CORP	1.063	0.076	0.075	0.074	0.075	0.039	0.060	0.061	0.087	0.090	0.089	0.073
GULF STATES UTILITIES CO	0.484	0.103	0.105	0.103	0.098	0.095	0.099	0.097	0.102	0.093	0.092	0.099
HAWAIIAN ELECTRIC CC	0.477	0.082	0.091	0.092	0.088	0.086	0.086	0.089	0.091	0.100	0.100	0.091
IDAHO POWER CC	0.363	0.074	0.081	0.087	0.092	0.096	0.094	0.066	0.096	0.081	0.093	0.088
INDIANAPOLIS POWER & LIGHT	0.694	0.116	0.114	0.109	0.103	0.104	0.118	0.103	0.086	0.097	0.105	0.105
KANSAS CITY POWER & LIGHT	0.481	0.096	0.099	0.094	0.088	0.088	0.087	0.081	0.086	0.091	0.094	0.090
KANSAS GAS & ELECTRIC	0.558	0.110	0.111	0.118	0.113	0.103	0.098	0.086	0.085	0.105	0.102	0.103
KENTUCKY UTILITIES CC	0.465	0.121	0.123	0.122	0.107	0.098	0.093	0.099	0.076	0.109	0.099	0.105
MAINE PUBLIC SERVICE	0.491	0.079	0.078	0.086	0.091	0.079	0.083	0.097	0.108	0.094	0.110	0.091
MIDDLE SOUTH UTILITIES	0.417	0.088	0.094	0.098	0.097	0.094	0.095	0.092	0.088	0.084	0.088	0.092
MINNESOTA POWER & LIGHT	0.390	0.085	0.096	0.090	0.082	0.084	0.080	0.085	0.085	0.100	0.104	0.089
NEVADA POWER CC	0.650	0.087	0.093	0.091	0.087	0.084	0.090	0.078	0.082	0.070	0.085	0.085
NEW ENGLAND ELECTRIC SYSTEM	0.533	0.081	0.078	0.073	0.074	0.075	0.084	0.079	0.089	0.097	0.100	0.083
NORTHEAST UTILITIES	0.582	0.086	0.081	0.079	0.063	0.069	0.076	0.076	0.073	0.072	0.082	0.076
OHIO EDISON CC	0.432	0.124	0.124	0.118	0.102	0.091	0.089	0.091	0.074	0.065	0.089	0.099
OKLAHOMA GAS & ELECTRIC	0.342	0.105	0.105	0.116	0.120	0.115	0.118	0.117	0.108	0.101	0.092	0.110
OTTER TAIL POWER CC	0.281	0.086	0.079	0.087	0.090	0.105	0.103	0.099	0.086	0.091	0.105	0.093
PENNSYLVANIA POWER & LIGHT	0.441	0.088	0.084	0.078	0.065	0.076	0.086	0.091	0.098	0.098	0.095	0.086
PORTLAND GENERAL ELECTRIC CO	0.444	0.080	0.075	0.084	0.081	0.096	0.092	0.085	0.080	0.090	0.092	0.086
POTOMAC ELECTRIC POWER	0.460	0.076	0.074	0.063	0.066	0.067	0.077	0.083	0.088	0.067	0.094	0.076
PUBLIC SERVICE CC CF IND	0.423	0.115	0.119	0.116	0.109	0.093	0.108	0.116	0.110	0.106	0.131	0.112
PUBLIC SERVICE CC CF N H	0.564	0.083	0.088	0.089	0.084	0.072	0.070	0.072	0.082	0.100	0.093	0.083
PUBLIC SERVICE CO CF N MEX	0.592	0.112	0.104	0.104	0.105	0.100	0.113	0.115	0.091	0.101	0.089	0.103
PUGET SOUND POWER & LIGHT	0.476	0.060	0.063	0.061	0.063	0.066	0.073	0.072	0.091	0.092	0.091	0.073
SAVANNAH ELEC & POWER	0.537	0.085	0.093	0.091	0.086	0.075	0.070	0.073	0.085	0.098	0.098	0.085
SOUTHERN CALIF EDISON CC	0.382	0.079	0.073	0.072	0.075	0.071	0.073	0.073	0.105	0.079	0.063	0.078
SOUTHERN CC	0.504	0.088	0.092	0.096	0.091	0.080	0.082	0.089	0.071	0.104	0.093	0.089
SOUTHWESTERN ELEC SERVICE	0.371	0.081	0.083	0.091	0.097	0.099	0.100	0.103	0.105	0.104	0.103	0.097
SOUTHWESTERN PUBLIC SERV CO	0.374	0.093	0.102	0.106	0.110	0.116	0.108	0.108	0.120	0.109	0.119	0.109
TAMPA ELECTRIC CC	0.773	0.106	0.101	0.104	0.098	0.075	0.098	0.096	0.079	0.104	0.105	0.097
TEXAS UTILITIES CC	0.199	0.125	0.128	0.134	0.129	0.118	0.121	0.115	0.113	0.105	0.110	0.120
TOLEDO EDISON COMPANY	0.418	0.107	0.110	0.109	0.100	0.093	0.093	0.091	0.078	0.094	0.089	0.096
UNION ELECTRIC CC	0.400	0.081	0.082	0.083	0.087	0.072	0.065	0.074	0.069	0.090	0.099	0.080
UNITED ILLUMINATING CC	0.412	0.096	0.089	0.094	0.085	0.063	0.095	0.068	0.083	0.076	0.074	0.082
UPPER PENINSULA POWER	0.440	0.087	0.087	0.086	0.075	0.073	0.095	0.099	0.070	0.076	0.093	0.085
UTAH POWER & LIGHT	0.344	0.080	0.080	0.076	0.075	0.076	0.082	0.077	0.074	0.085	0.107	0.081
VIRGINIA ELECTRIC & POWER	0.617	0.096	0.097	0.093	0.084	0.076	0.074	0.079	0.069	0.088	0.090	0.085
ARIZONA PUBLIC SERVICE CO	0.491	0.061	0.067	0.073	0.076	0.069	0.074	0.081	0.076	0.089	0.086	0.075
BALTIMORE GAS & ELECTRIC	0.420	0.112	0.113	0.112	0.102	0.095	0.089	0.089	0.074	0.083	0.090	0.096
CENTRAL HUDSON GAS & ELEC	0.480	0.081	0.082	0.078	0.061	0.083	0.090	0.083	0.065	0.086	0.092	0.080
CENTRAL ILLINOIS LIGHT	0.487	0.100	0.099	0.101	0.105	0.102	0.099	0.087	0.079	0.078	0.094	0.095
CENTRAL ILL PUBLIC SERVICE	0.567	0.113	0.115	0.114	0.107	0.105	0.092	0.097	0.089	0.094	0.091	0.101
CINCINNATI GAS & ELECTRIC	0.264	0.123	0.123	0.118	0.104	0.096	0.102	0.099	0.082	0.082	0.083	0.101
CONSOLIDATED EDISON CF N.Y.	0.802	0.059	0.061	0.058	0.051	0.055	0.055	0.059	0.071	0.082	0.092	0.064
CONSUMERS POWER CC	0.711	0.105	0.099	0.093	0.089	0.077	0.076	0.073	0.058	0.080	0.095	0.085
DAYTON POWER & LIGHT	0.479	0.127	0.109	0.097	0.086	0.083	0.081	0.070	0.071	0.096	0.097	0.092
DELMARVA POWER & LIGHT	0.472	0.100	0.103	0.097	0.079	0.080	0.082	0.082	0.083	0.074	0.070	0.085
FITCHBURG GAS & ELEC LIGHT	0.387	0.079	0.087	0.084	0.084	0.083	0.086	0.077	0.074	0.086	0.095	0.083
ILLINOIS POWER CC	0.497	0.128	0.126	0.125	0.118	0.100	0.095	0.096	0.089	0.104	0.099	0.108
INTERSTATE POWER CC	0.436	0.090	0.091	0.093	0.088	0.088	0.089	0.087	0.086	0.088	0.083	0.089
IOWA ELECTRIC LIGHT & PWR	0.713	0.091	0.090	0.088	0.085	0.075	0.069	0.086	0.064	0.082	0.093	0.084
IOWA-ILLINOIS GAS & ELEC	0.734	0.113	0.105	0.099	0.088	0.075	0.110	0.095	0.098	0.105	0.112	0.100
IOWA POWER & LIGHT	0.353	0.095	0.093	0.090	0.078	0.084	0.083	0.097	0.090	0.106	0.102	0.092
IOWA PUBLIC SERVICE CC	0.304	0.103	0.110	0.103	0.093	0.100	0.087	0.084	0.087	0.102	0.106	0.098
IOWA SOUTHERN UTILITIES CO	0.571	0.116	0.119	0.129	0.128	0.124	0.128	0.111	0.106	0.107	0.109	0.118
KANSAS POWER & LIGHT	0.281	0.103	0.111	0.118	0.119	0.118	0.113	0.113	0.095	0.099	0.095	0.108
LAKE SUPERIOR DIST POWER CO	0.315	0.080	0.088	0.077	0.073	0.082	0.092	0.085	0.089	0.097	0.088	0.085
LONG ISLAND LIGHTING	0.530	0.085	0.084	0.090	0.086	0.086	0.081	0.078	0.077	0.090	0.096	0.085
LOUISVILLE GAS & ELECTRIC	0.436	0.132	0.140	0.142	0.132	0.123	0.112	0.109	0.093	0.110	0.106	0.120
MADISON GAS & ELECTRIC CO	0.367	0.077	0.079	0.088	0.077	0.080	0.077	0.094	0.089	0.113	0.108	0.088
MISSOURI PUBLIC SERVICE CO	0.631	0.092	0.084	0.088	0.091	0.079	0.085	0.081	0.094	0.099	0.110	0.090
MONTANA POWER CC	0.311	0.119	0.114	0.129	0.127	0.123	0.120	0.116	0.100	0.090	0.075	0.111
NEW ENGLAND GAS & ELECTRIC	0.523	0.094	0.085	0.085	0.086	0.091	0.084	0.081	0.036	0.080	0.097	0.087
NEW YORK STATE ELEC & GAS	0.534	0.089	0.083	0.077	0.072	0.065	0.074	0.076	0.081	0.078	0.083	0.078
NIAGARA MOHAWK POWER	0.490	0.076	0.064	0.064	0.059	0.062	0.069	0.058	0.067	0.084	0.075	0.068
NORTHERN INDIANA PUBLIC SERV	0.337	0.117	0.116	0.114	0.120	0.104	0.104	0.098	0.085	0.098	0.107	0.106
NORTHERN STATES POWER	0.477	0.089	0.089	0.089	0.088	0.089	0.095	0.086	0.097	0.105	0.110	0.093
NORTHWESTERN PUBLIC SERV CO	0.392	0.089	0.088	0.093	0.097	0.103	0.099	0.090	0.086	0.083	0.096	0.093
ORANGE & ROCKLAND UTILITIES	0.637	0.079	0.076	0.072	0.077	0.055	0.067	0.075	0.070	0.092	0.099	0.076
PACIFIC GAS & ELECTRIC	0.240	0.084	0.084	0.083	0.077	0.086	0.084	0.083	0.080	0.070	0.073	0.080
PACIFIC POWER & LIGHT	0.487	0.065	0.067	0.068	0.070	0.078	0.081	0.077	0.071	0.078	0.082	0.074
PHILADELPHIA ELECTRIC CO	0.438	0.091	0.084	0.082	0.074	0.083	0.084	0.083	0.083	0.089	0.093	0.085
PUBLIC SERVICE CC CF CCLO	0.365	0.082	0.085	0.084	0.082	0.075	0.076	0.076	0.068	0.087	0.082	0.080
PUBLIC SERVICE ELEC & GAS	0.609	0.085	0.086	0.082	0.070	0.082	0.070	0.067	0.074	0.079	0.094	0.079
ROCHESTER GAS & ELECTRIC	0.606	0.085	0.078	0.074	0.070	0.069	0.071	0.069	0.069	0.082	0.096	0.077
ST JOSEPH LIGHT & POWER	0.599	0.083	0.094	0.089	0.095	0.106	0.105	0.094	0.089	0.092	0.097	0.095
SAN DIEGO GAS & ELECTRIC	0.511	0.087	0.088	0.092	0.084	0.078	0.069	0.069	0.081	0.059	0.084	0.079
SIERRA PACIFIC POWER CC	0.502	0.068	0.070	0.068	0.073	0.074	0.078	0.083	0.089	0.085	0.101	0.079
SOUTH CAROLINA ELEC & GAS	0.841	0.098	0.102	0.094	0.081	0.075	0.081	0.076	0.080	0.099	0.095	0.088
SOUTHERN INDIANA GAS & ELEC	0.445	0.113	0.117	0.119	0.120	0.114	0.126	0.130	0.115	0.119	0.128	0.120
TUCSON GAS & ELECTRIC	0.532	0.096	0.096	0.099	0.100	0.084	0.083	0.078	0.071	0.093	0.100	0.090
WASHINGTON WATER POWER	0.282	0.073	0.080	0.080	0.081	0.082	0.080	0.081	0.085	0.087	0.098	0.083
WISCONSIN ELECTRIC POWER	0.140	0.097	0.095	0.092	0.084	0.088	0.105	0.118	0.108	0.106	0.116	0.100
WISCONSIN POWER & LIGHT	0.419	0.111	0.112	0.107	0.103	0.093	0.095	0.101	0.098	0.123	0.140	0.108
WISCONSIN PUBLIC SERVICE	0.291	0.106	0.097	0.091	0.091	0.086	0.099	0.105	0.106	0.127	0.147	0.106
MONTANA-DAKOTA UTILITIES	0.262	0.083	0.091	0.094	0.099	0.095	0.093	0.080	0.084	0.094	0.105	0.092

TABLE NO.12

RATE OF RETURN MEASURE 2

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
ALLEGHENY POWER SYSTEM	0.525	0.093	0.088	0.080	0.078	0.074	0.080	0.065	0.080	0.111	0.117	0.089
AMERICAN ELECTRIC POWER	0.516	0.088	0.083	0.072	0.066	0.061	0.060	0.071	0.072	0.089	0.098	0.076
ATLANTIC CITY ELECTRIC	0.555	0.084	0.085	0.077	0.067	0.060	0.070	0.076	0.081	0.103	0.111	0.081
BANGOR HYDRO-ELEC CO	0.524	0.100	0.093	0.083	0.072	0.066	0.085	0.061	0.070	0.090	0.063	0.078
BLACK HILLS POWER & LIGHT CO	0.428	0.033	0.083	0.076	0.077	0.098	0.102	0.105	0.107	0.105	0.102	0.094
BOSTON EDISON CO	0.525	0.089	0.089	0.080	0.063	0.056	0.046	0.069	0.083	0.090	0.091	0.075
BRASCAN LTD-CL A	0.614	0.069	0.070	0.069	0.072	0.082	0.086	0.092	0.072	0.061	0.059	0.073
CAROLINA POWER & LIGHT	0.609	0.090	0.094	0.085	0.053	0.064	0.080	0.072	0.073	0.112	0.137	0.086
CENTRAL & SOUTH WEST CORP	0.398	0.115	0.121	0.125	0.119	0.116	0.122	0.123	0.126	0.124	0.118	0.122
CENTRAL MAINE POWER CO	0.310	0.097	0.095	0.090	0.091	0.082	0.096	0.090	0.078	0.086	0.094	0.090
CENTRAL VERMONT PUB SERV	0.766	0.074	0.064	0.057	0.052	0.040	0.055	0.031	0.065	0.094	0.095	0.063
CLEVELAND ELECTRIC ILLUM	0.384	0.126	0.123	0.107	0.092	0.090	0.084	0.065	0.107	0.090	0.103	0.101
COLUMBUS & SOUTHERN OHIO	0.603	0.099	0.092	0.083	0.067	0.061	0.066	0.077	0.063	0.113	0.102	0.082
COMMONWEALTH EDISON	0.307	0.111	0.108	0.094	0.081	0.071	0.078	0.087	0.087	0.095	0.102	0.091
COMMUNITY PUBLIC SERVICE	0.435	0.083	0.089	0.096	0.101	0.103	0.108	0.107	0.095	0.096	0.108	0.099
CONCORD ELECTRIC CO	0.000	0.063	0.079	0.076	0.075	0.073	0.082	0.073	0.086	0.110	0.105	0.082
DETROIT EDISON CO	0.714	0.086	0.081	0.081	0.064	0.060	0.063	0.068	0.065	0.065	0.075	0.072
DUKE POWER CO	0.512	0.104	0.096	0.082	0.050	0.052	0.047	0.065	0.034	0.101	0.123	0.080
DUQUESNE LIGHT CO	0.504	0.101	0.098	0.083	0.067	0.080	0.075	0.063	0.097	0.112	0.095	0.089
EASTERN UTILITIES ASSOC	0.761	0.104	0.095	0.079	0.072	0.080	0.082	0.054	0.085	0.079	0.119	0.085
EDISON SAULT ELECTRIC	[illegible]	0.113	0.114	0.101	0.089	0.078	0.080	0.094	0.105	0.093	0.082	0.094
EL PASO ELECTRIC CO	0.353	0.123	0.123	0.128	0.124	0.118	0.120	0.120	0.116	0.111	0.117	0.120
EMPIRE DISTRICT ELECTRIC CO	0.326	0.110	0.113	0.091	0.101	0.096	0.093	0.093	0.094	0.098	0.103	0.099
FLORIDA POWER & LIGHT	0.575	0.110	0.116	0.114	0.103	0.097	0.083	0.103	0.097	0.138	0.097	0.106
FLORIDA POWER CORP	0.636	0.101	0.105	0.103	0.096	0.089	0.094	0.080	0.073	0.112	0.119	0.096
GENERAL PUBLIC UTILITIES	0.629	0.069	0.064	0.052	0.050	0.059	0.065	0.070	0.084	0.091	0.108	0.071
GREEN MOUNTAIN POWER CORP	1.063	0.074	0.068	0.063	0.064	0.027	0.050	0.061	0.088	0.091	0.090	0.067
GULF STATES UTILITIES CO	0.484	0.100	0.098	0.095	0.088	0.087	0.090	0.095	0.109	0.100	0.100	0.096
HAWAIIAN ELECTRIC CO	0.477	0.081	0.088	0.090	0.084	0.084	0.082	0.097	0.086	0.101	0.100	0.088
IDAHO POWER CO	0.363	0.068	0.061	0.087	0.091	0.095	0.090	0.084	0.090	0.085	0.095	0.086
INDIANAPOLIS POWER & LIGHT	0.694	0.110	0.107	0.099	0.100	0.099	0.107	0.098	0.089	0.105	0.120	0.103
KANSAS CITY POWER & LIGHT	0.431	0.094	0.092	0.090	0.085	0.082	0.077	0.076	0.089	0.095	0.104	0.087
KANSAS GAS & ELECTRIC	0.553	0.105	0.110	0.116	0.107	0.092	0.091	0.079	0.086	0.111	0.116	0.100
KENTUCKY UTILITIES CO	0.465	0.121	0.121	0.117	0.097	0.090	0.035	0.099	0.085	0.116	0.107	0.104
MAINE PUBLIC SERVICE	0.491	0.079	0.077	0.085	0.090	0.078	0.083	0.097	0.107	0.093	0.106	0.090
MIDDLE SOUTH UTILITIES	0.417	0.083	0.090	0.094	0.091	0.087	0.085	0.090	0.089	0.087	0.097	0.089
MINNESOTA POWER & LIGHT	0.390	0.084	0.094	0.088	0.079	0.075	0.064	0.076	0.084	0.102	0.108	0.086
NEVADA POWER CO	0.650	0.082	0.087	0.085	0.074	0.075	0.082	0.073	0.085	0.067	0.086	0.080
NEW ENGLAND ELECTRIC SYSTEM	0.533	0.079	0.073	0.067	0.071	0.070	0.077	0.076	0.085	0.098	0.103	0.080
NORTHEAST UTILITIES	0.582	0.083	0.075	0.070	0.051	0.058	0.062	0.070	0.075	0.065	0.082	0.069
OHIO EDISON CO	0.432	0.115	0.118	0.115	0.097	0.083	0.090	0.090	0.071	0.091	0.095	0.096
OKLAHOMA GAS & ELECTRIC	0.342	0.103	0.101	0.112	0.114	0.111	0.114	0.119	0.117	0.111	0.101	0.110
OTTER TAIL POWER CO	0.281	0.085	0.079	0.086	0.090	0.103	0.097	0.102	0.103	0.104	0.108	0.096
PENNSYLVANIA POWER & LIGHT	0.441	0.083	0.077	0.071	0.056	0.063	0.076	0.087	0.105	0.101	0.100	0.082
PORTLAND GENERAL ELECTRIC CO	0.444	0.077	0.077	0.083	0.079	0.092	0.083	0.082	0.094	0.101	0.105	0.086
POTOMAC ELECTRIC POWER	0.460	0.076	0.074	0.063	0.066	0.067	0.077	0.090	0.107	0.081	0.110	0.081
PUBLIC SERVICE CO OF IND	0.423	0.112	0.115	0.110	0.102	0.088	0.103	0.119	0.122	0.119	0.142	0.113
PUBLIC SERVICE CO OF N H	0.564	0.077	0.064	0.086	0.078	0.068	0.062	0.066	0.084	0.101	0.094	0.080
PUBLIC SERVICE CO OF N MEX	0.592	0.108	0.098	0.055	0.102	0.097	0.103	0.107	0.097	0.114	0.102	0.103
PUGET SOUND POWER & LIGHT	0.476	0.058	0.061	0.060	0.061	0.062	0.070	0.071	0.096	0.092	0.092	0.072
SAVANNAH ELEC & POWER	0.537	0.085	0.093	0.087	0.078	0.061	0.060	0.067	0.087	0.103	0.103	0.082
SOUTHERN CALIF EDISON CO	0.382	0.076	0.069	0.066	0.070	0.066	0.071	0.073	0.111	0.083	0.087	0.077
SOUTHERN CO	0.504	0.085	0.089	0.092	0.084	0.070	0.070	0.085	0.072	0.117	0.101	0.086
SOUTHWESTERN ELEC SERVICE	0.371	0.060	0.082	0.091	0.096	0.098	0.099	0.103	0.105	0.104	0.103	0.096
SOUTHWESTERN PUBLIC SERV CO	0.374	0.092	0.098	0.106	0.107	0.111	0.107	0.110	0.124	0.116	0.121	0.109
TAMPA ELECTRIC CO	0.773	0.100	0.098	0.096	0.087	0.072	0.092	0.094	0.079	0.113	0.113	0.094
TEXAS UTILITIES CO	0.199	0.123	0.125	0.130	0.125	0.110	0.115	0.115	0.119	0.112	0.126	0.120
TOLEDO EDISON COMPANY	0.418	0.103	0.106	0.107	0.096	0.085	0.082	0.086	0.084	0.115	0.111	0.098
UNION ELECTRIC CO	0.400	0.076	0.077	0.075	0.077	0.062	0.056	0.072	0.069	0.093	0.109	0.077
UNITED ILLUMINATING CO	0.412	0.088	0.079	0.093	0.085	0.063	0.092	0.067	0.088	0.074	0.074	0.080
UPPER PENINSULA POWER	0.440	0.086	0.086	0.086	0.074	0.072	0.094	0.097	0.065	0.074	0.098	0.084
UTAH POWER & LIGHT	0.344	0.078	0.076	0.075	0.069	0.069	0.077	0.075	0.073	0.087	0.114	0.080
VIRGINIA ELECTRIC & POWER	0.617	0.095	0.091	0.083	0.070	0.056	0.049	0.068	0.066	0.096	0.101	0.077
ARIZONA PUBLIC SERVICE CO	0.491	0.060	0.062	0.070	0.075	0.066	0.068	0.081	0.078	0.096	0.092	0.075
BALTIMORE GAS & ELECTRIC	0.421	0.112	0.111	0.107	0.094	0.081	0.069	0.084	0.075	0.103	0.103	0.094
CENTRAL HUDSON GAS & ELEC	0.480	0.074	0.080	0.076	0.057	0.075	0.077	0.080	0.062	0.089	0.094	0.077
CENTRAL ILLINOIS LIGHT	0.437	0.095	0.096	0.099	0.100	0.091	0.091	0.089	0.086	0.088	0.101	0.094
CENTRAL ILL PUBLIC SERVICE	0.567	0.112	0.115	0.113	0.102	0.095	0.082	0.087	0.093	0.099	0.098	0.100
CINCINNATI GAS & ELECTRIC	0.234	0.120	0.118	0.110	0.094	0.087	0.092	0.097	0.085	0.085	0.096	0.097
CONSOLIDATED EDISON CF N.Y.	0.302	0.057	0.057	0.054	0.045	0.048	0.046	0.056	0.073	0.083	0.095	0.061
CONSUMERS POWER CO	0.711	0.104	0.096	0.088	0.082	0.066	0.065	0.069	0.058	0.084	0.100	0.081
DAYTON POWER & LIGHT	0.479	0.124	0.102	0.088	0.077	0.077	0.074	0.067	0.071	0.100	0.102	0.088
DELMARVA POWER & LIGHT	0.472	0.099	0.099	0.090	0.070	0.064	0.065	0.074	0.087	0.075	0.071	0.079
FITCHBURG GAS & ELEC LIGHT	0.387	0.078	0.087	0.083	0.083	0.082	0.083	0.074	0.074	0.082	0.096	0.082
ILLINOIS POWER CO	0.497	0.126	0.123	0.117	0.110	0.095	0.087	0.093	0.093	0.110	0.106	0.106
INTERSTATE POWER CO	0.436	0.086	0.090	0.093	0.086	0.088	0.088	0.088	0.090	0.093	0.093	0.089
IOWA ELECTRIC LIGHT & PWR	0.713	0.084	0.087	0.087	0.080	0.065	0.071	0.071	0.062	0.092	0.093	0.078
IOWA-ILLINOIS GAS & ELEC	0.734	0.108	0.098	0.088	0.074	0.063	0.098	0.095	0.098	0.104	0.114	0.094
IOWA POWER & LIGHT	0.353	0.094	0.091	0.087	0.076	0.084	0.082	0.100	0.093	0.108	0.109	0.092
IOWA PUBLIC SERVICE CO	0.304	0.102	0.109	0.100	0.087	0.090	0.080	0.085	0.099	0.102	0.110	0.095
IOWA SOUTHERN UTILITIES CO	0.571	0.106	0.112	0.125	0.127	0.123	0.127	0.115	0.117	0.107	0.112	0.118
KANSAS POWER & LIGHT	0.281	0.102	0.110	0.114	0.110	0.113	0.113	0.112	0.093	0.101	0.102	0.107
LAKE SUPERIOR DIST POWER CO	0.315	0.080	0.087	0.075	0.072	0.082	0.091	0.089	0.097	0.099	0.089	0.086
LONG ISLAND LIGHTING	0.530	0.082	0.081	0.088	0.081	0.079	0.073	0.077	0.079	0.094	0.107	0.084
LOUISVILLE GAS & ELECTRIC	0.436	0.132	0.140	0.142	0.132	0.123	0.112	0.115	0.105	0.122	0.129	0.125
MADISON GAS & ELECTRIC CO	0.367	0.076	0.077	0.084	0.070	0.066	0.061	0.091	0.100	0.124	0.116	0.086
MISSOURI PUBLIC SERVICE CO	0.631	0.083	0.068	0.073	0.089	0.077	0.082	0.080	0.094	0.100	0.111	0.086
MONTANA POWER CO	0.311	0.116	0.111	0.128	0.127	0.122	0.118	0.118	0.104	0.091	0.074	0.111
NEW ENGLAND GAS & ELECTRIC	0.529	0.083	0.081	0.083	0.093	0.099	0.081	0.081	0.086	0.079	0.103	0.085
NEW YORK STATE ELEC & GAS	0.534	0.086	0.077	0.067	0.067	0.063	0.071	0.076	0.084	0.080	0.089	0.076
NIAGARA MOHAWK POWER	0.490	0.071	0.057	0.057	0.054	0.058	0.062	0.054	0.066	0.086	0.073	0.064
NORTHERN INDIANA PUBLIC SERV	0.337	0.113	0.112	0.112	0.116	0.101	0.096	0.096	0.090	0.103	0.107	0.105
NORTHERN STATES POWER	0.477	0.083	0.085	0.082	0.078	0.076	0.080	0.075	0.087	0.111	0.117	0.087
NORTHWESTERN PUBLIC SERV CO	0.392	0.088	0.087	0.092	0.096	0.100	0.091	0.091	0.099	0.091	0.099	0.093
ORANGE & ROCKLAND UTILITIES	0.637	0.078	0.071	0.065	0.073	0.046	0.056	0.074	0.072	0.092	0.100	0.073
PACIFIC GAS & ELECTRIC	0.240	0.080	0.081	0.081	0.072	0.080	0.076	0.080	0.082	0.070	0.073	0.078
PACIFIC POWER & LIGHT	0.437	0.064	0.065	0.066	0.063	0.067	0.069	0.076	0.071	0.075	0.083	0.070
PHILADELPHIA ELECTRIC CO	0.438	0.086	0.082	0.078	0.064	0.069	0.068	0.077	0.086	0.096	0.102	0.081
PUBLIC SERVICE CO OF COLO	0.365	0.079	0.080	0.082	0.078	0.065	0.068	0.070	0.070	0.089	0.086	0.077
PUBLIC SERVICE ELEC & GAS	0.609	0.083	0.082	0.077	0.062	0.070	0.056	0.058	0.074	0.084	0.107	0.075
ROCHESTER GAS & ELECTRIC	0.606	0.081	0.069	0.062	0.063	0.069	0.070	0.090	0.070	0.085	0.088	0.075
ST JOSEPH LIGHT & POWER	0.599	0.080	0.089	0.085	0.095	0.106	0.102	0.093	0.094	0.096	0.101	0.094
SAN DIEGO GAS & ELECTRIC	0.511	0.086	0.087	0.091	0.082	0.074	0.065	0.066	0.083	0.059	0.088	0.078
SIERRA PACIFIC POWER CO	0.502	0.065	0.065	0.067	0.069	0.069	0.076	0.082	0.085	0.084	0.101	0.076
SOUTH CAROLINA ELEC & GAS	0.641	0.095	0.099	0.086	0.069	0.065	0.071	0.070	0.082	0.106	0.106	0.085
SOUTHERN INDIANA GAS & ELEC	0.445	0.113	0.116	0.113	0.112	0.108	0.111	0.122	0.118	0.122	0.133	0.117
TUCSON GAS & ELECTRIC	0.532	0.092	0.094	0.094	0.096	0.077	0.070	0.069	0.063	0.101	0.112	0.087
WASHINGTON WATER POWER	0.282	0.073	0.078	0.079	0.078	0.077	0.074	0.081	0.084	0.088	0.098	0.081
WISCONSIN ELECTRIC POWER	0.140	0.097	0.085	0.086	0.076	0.083	0.101	0.113	0.110	0.110	0.121	0.099
WISCONSIN POWER & LIGHT	0.419	0.110	0.109	0.099	0.098	0.083	0.083	0.100	0.107	0.136	0.151	0.108
WISCONSIN PUBLIC SERVICE	0.291	0.105	0.094	0.084	0.085	0.076	0.086	0.105	0.118	0.138	0.156	0.105
MONTANA-DAKOTA UTILITIES	0.262	0.062	0.090	0.094	0.097	0.094	0.091	0.077	0.078	0.091	0.104	0.090

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
ALLEGHENY POWER SYSTEM	0.525	0.204	0.197	0.176	0.151	0.136	0.156	0.151	0.122	0.201	0.203	0.170
AMERICAN ELECTRIC POWER	0.516	0.183	0.177	0.153	0.133	0.123	0.119	0.120	0.082	0.118	0.141	0.135
ATLANTIC CITY ELECTRIC	0.555	0.190	0.197	0.176	0.139	0.120	0.148	0.137	0.122	0.167	0.169	0.157
BANGOR HYDRO-ELEC CO	0.524	0.213	0.192	0.176	0.145	0.111	0.169	0.100	0.118	0.178	0.079	0.148
BLACK HILLS POWER & LIGHT CO	0.428	0.143	0.147	0.136	0.122	0.172	0.170	0.170	0.165	0.162	0.154	0.155
BOSTON EDISON CO	0.525	0.167	0.168	0.157	0.126	0.109	0.091	0.069	0.096	0.115	0.110	0.123
BRASCAN LTD-CL A	0.614	0.071	0.071	0.069	0.068	0.077	0.080	0.097	0.079	0.056	0.060	0.073
CAROLINA POWER & LIGHT	0.609	0.186	0.201	0.165	0.091	0.124	0.182	0.115	0.086	0.167	0.195	0.151
CENTRAL & SOUTH WEST CORP	0.383	0.217	0.228	0.243	0.222	0.207	0.219	0.217	0.200	0.151	0.165	0.211
CENTRAL MAINE POWER CO	0.310	0.191	0.186	0.176	0.174	0.144	0.174	0.153	0.117	0.136	0.145	0.160
CENTRAL VERMONT PUB SERV	0.766	0.164	0.131	0.110	0.060	0.051	0.086	-0.004	0.069	0.131	0.135	0.093
CLEVELAND ELECTRIC ILLUM	0.384	0.228	0.238	0.221	0.190	0.172	0.169	0.145	0.175	0.141	0.153	0.183
COLUMBUS & SOUTHERN OHIO	0.603	0.201	0.193	0.175	0.128	0.097	0.122	0.126	0.055	0.181	0.134	0.143
COMMONWEALTH EDISON	0.307	0.219	0.215	0.191	0.164	0.144	0.161	0.154	0.134	0.148	0.147	0.163
COMMUNITY PUBLIC SERVICE	0.435	0.162	0.174	0.188	0.185	0.187	0.202	0.193	0.144	0.151	0.179	0.177
CONCORD ELECTRIC CO	0.000	0.100	0.139	0.128	0.122	0.126	0.142	0.103	0.133	0.220	0.185	0.140
DETROIT EDISON CO	0.714	0.160	0.155	0.153	0.118	0.107	0.121	0.103	0.084	0.088	[illegible]	0.118
DUKE POWER CO	0.612	0.216	0.216	0.186	0.093	0.109	0.091	0.113	0.121	0.152	0.186	0.148
DUQUESNE LIGHT CO	0.504	0.244	0.236	0.208	0.154	0.173	0.156	0.132	0.126	0.148	0.116	0.169
EASTERN UTILITIES ASSOC	0.761	0.209	0.186	0.146	0.130	0.159	0.164	0.052	0.081	0.097	0.164	0.139
EDISON SAULT ELECTRIC	0.000	0.232	0.225	0.192	0.160	0.130	0.136	0.166	0.157	0.138	0.116	0.169
EL PASO ELECTRIC CO	0.358	0.232	0.246	0.254	0.233	0.223	0.230	0.212	0.196	0.166	0.190	0.220
EMPIRE DISTRICT ELECTRIC CO	0.326	0.209	0.221	0.209	0.209	0.170	0.161	0.153	0.147	0.156	0.165	0.180
FLORIDA POWER & LIGHT	0.575	0.187	0.203	0.194	0.171	0.183	0.164	0.178	0.135	0.205	0.134	0.175
FLORIDA POWER CORP	0.636	0.152	0.206	0.210	0.183	0.171	0.174	0.147	0.091	0.169	0.155	0.173
GENERAL PUBLIC UTILITIES	0.629	0.135	0.124	0.089	0.064	0.096	0.117	0.111	0.116	0.122	0.148	0.112
GREEN MOUNTAIN POWER CORP	1.063	0.163	0.150	0.136	0.095	0.003	0.068	0.049	0.135	0.155	0.166	0.114
GULF STATES UTILITIES CO	0.484	0.216	0.221	0.205	0.188	0.163	0.178	0.172	0.176	0.152	0.145	0.181
HAWAIIAN ELECTRIC CO	0.477	0.142	0.163	0.162	0.147	0.135	0.129	0.132	0.135	0.158	0.155	0.146
IDAHO POWER CO	0.363	0.131	0.148	0.160	0.169	0.180	0.174	0.147	0.147	0.112	0.143	0.151
INDIANAPOLIS POWER & LIGHT	0.694	0.247	0.246	0.238	0.213	0.209	0.239	0.194	0.136	0.168	0.180	0.207
KANSAS CITY POWER & LIGHT	0.481	0.182	0.190	0.178	0.156	0.155	0.148	0.131	0.143	0.152	0.151	0.159
KANSAS GAS & ELECTRIC	0.558	0.222	0.221	0.236	0.214	0.185	0.170	0.143	0.134	0.153	0.183	0.190
KENTUCKY UTILITIES CO	0.465	0.203	0.204	0.207	0.178	0.160	0.149	0.155	0.100	0.182	0.148	0.169
MAINE PUBLIC SERVICE	0.491	0.144	0.135	0.154	0.155	0.124	0.137	0.173	0.202	0.162	0.190	0.158
MIDDLE SOUTH UTILITIES	0.417	0.169	0.185	0.194	0.185	0.169	0.174	0.165	0.136	0.124	0.133	0.163
MINNESOTA POWER & LIGHT	0.390	0.170	0.196	0.184	0.166	0.175	0.161	0.156	0.150	0.155	0.184	0.174
NEVADA POWER CO	0.550	0.157	0.166	0.162	0.137	0.128	0.153	0.106	0.096	0.058	0.111	0.127
NEW ENGLAND ELECTRIC SYSTEM	0.533	0.160	0.148	0.128	0.128	0.138	0.169	0.133	0.143	0.173	0.177	0.150
NORTHEAST UTILITIES	0.582	0.171	0.155	0.144	0.086	0.105	0.125	0.110	0.091	0.096	0.121	0.120
OHIO EDISON CO	0.432	0.241	0.236	0.225	0.185	0.158	0.153	0.154	0.103	0.127	0.131	0.172
OKLAHOMA GAS & ELECTRIC	0.342	0.226	0.230	0.259	0.260	0.237	0.229	0.221	0.186	0.169	0.144	0.216
OTTER TAIL POWER CO	0.281	0.173	0.152	0.168	0.173	0.212	0.203	0.184	0.138	0.152	0.187	0.174
PENNSYLVANIA POWER & LIGHT	0.441	0.199	0.181	0.154	0.099	0.130	0.156	0.160	0.180	0.177	0.153	0.159
PORTLAND GENERAL ELECTRIC CO	0.444	0.129	0.125	0.135	0.121	0.153	0.141	0.118	0.112	0.130	0.133	0.131
POTOMAC ELECTRIC POWER	0.460	0.144	0.133	0.095	0.094	0.095	0.127	0.140	0.143	0.071	0.159	0.120
PUBLIC SERVICE CO OF IND	0.423	0.210	0.223	0.217	0.205	0.165	0.196	0.205	0.193	0.180	0.232	0.203
PUBLIC SERVICE CO OF N H	0.564	0.165	0.185	0.192	0.166	0.118	0.116	0.104	0.105	0.172	0.142	0.146
PUBLIC SERVICE CO OF N MEX	0.592	0.216	0.203	0.197	0.192	0.176	0.155	0.155	0.131	0.160	0.129	0.180
PUGET SOUND POWER & LIGHT	0.476	0.096	0.101	0.090	0.087	0.095	0.115	0.105	0.151	0.151	0.142	0.113
SAVANNAH ELEC & POWER	0.537	0.162	0.183	0.173	0.153	0.119	0.099	0.078	0.093	0.137	0.118	0.132
SOUTHERN CALIF EDISON CO	0.382	0.143	0.125	0.120	0.123	0.109	0.112	0.111	0.157	0.123	0.127	0.129
SOUTHERN CO	0.504	0.175	0.175	0.189	0.161	0.121	0.123	0.132	0.078	0.175	0.131	0.146
SOUTHWESTERN ELEC SERVICE	0.371	0.180	0.183	0.208	0.218	0.212	0.210	0.213	0.210	0.205	0.190	0.203
SOUTHWESTERN PUBLIC SERV CO	0.374	0.199	0.219	0.230	0.238	0.239	0.209	0.215	0.248	0.217	0.245	0.226
TAMPA ELECTRIC CO	0.773	0.228	0.203	0.198	0.180	0.118	0.179	0.170	0.109	0.179	0.177	0.174
TEXAS UTILITIES CO	0.199	0.257	0.265	0.277	0.261	0.225	0.233	0.212	0.151	0.177	0.186	0.229
TOLEDO EDISON COMPANY	0.418	0.247	0.257	0.250	0.221	0.202	0.202	0.178	0.117	0.167	0.147	0.199
UNION ELECTRIC CO	0.400	0.171	0.163	0.164	0.167	0.110	0.086	0.110	0.086	0.156	0.187	0.140
UNITED ILLUMINATING CO	0.412	0.205	0.186	0.203	0.174	0.107	0.213	0.118	0.145	0.111	0.102	0.156
UPPER PENINSULA POWER	0.440	0.168	0.164	0.157	0.123	0.121	0.176	0.175	0.086	0.115	0.182	0.147
UTAH POWER & LIGHT	0.344	0.153	0.151	0.138	0.129	0.127	0.143	0.115	0.096	0.125	0.172	0.135
VIRGINIA ELECTRIC & POWER	0.617	0.193	0.189	0.175	0.150	0.114	0.106	0.111	0.072	0.120	0.124	0.135
ARIZONA PUBLIC SERVICE CO	0.491	0.102	0.120	0.134	0.143	0.124	0.124	0.131	0.105	0.146	0.117	0.125
BALTIMORE GAS & ELECTRIC	0.420	0.240	0.247	0.238	0.196	0.173	0.150	0.140	0.095	0.123	0.140	0.175
CENTRAL HUDSON GAS & ELEC	0.480	0.170	0.171	0.152	0.089	0.163	0.183	0.142	0.068	0.136	0.154	0.143
CENTRAL ILLINOIS LIGHT	0.487	0.187	0.186	0.192	0.203	0.187	0.175	0.141	0.112	0.111	0.153	0.165
CENTRAL ILL PUBLIC SERVICE	0.567	0.245	0.245	0.238	0.208	0.198	0.158	0.145	0.145	0.159	0.145	0.189
CINCINNATI GAS & ELECTRIC	0.284	0.255	0.258	0.246	0.214	0.184	0.201	0.189	0.134	0.127	0.125	0.193
CONSOLIDATED EDISON OF N.Y.	0.802	0.099	0.102	0.090	0.059	0.069	0.063	0.072	0.097	0.130	0.150	0.093
CONSUMERS POWER CO	0.711	0.198	0.186	0.170	0.157	0.121	0.115	0.107	0.055	0.114	0.150	0.137
DAYTON POWER & LIGHT	0.479	0.277	0.236	0.212	0.161	0.154	0.142	0.103	0.096	0.166	0.160	0.171
DELMARVA POWER & LIGHT	0.472	0.203	0.216	0.194	0.138	0.133	0.130	0.124	0.117	0.050	0.082	0.143
FITCHBURG GAS & ELEC LIGHT	0.387	0.133	0.151	0.126	0.116	0.112	0.125	0.099	0.071	0.115	0.141	0.119
ILLINOIS POWER CO	0.497	0.274	0.274	0.270	0.244	0.186	0.165	0.164	0.143	0.179	0.151	0.205
INTERSTATE POWER CO	0.436	0.204	0.201	0.209	0.189	0.190	0.193	0.194	0.186	0.179	0.156	0.190
IOWA ELECTRIC LIGHT & PWR	0.713	0.176	0.174	0.167	0.156	0.126	0.163	0.130	0.045	0.116	0.148	0.140
IOWA-ILLINOIS GAS & ELEC	0.734	0.215	0.207	0.196	0.157	0.120	0.214	0.156	0.162	0.181	0.187	0.180
IOWA POWER & LIGHT	0.353	0.208	0.202	0.190	0.145	0.160	0.150	0.185	0.154	0.159	0.178	0.177
IOWA PUBLIC SERVICE CO	0.304	0.200	0.213	0.157	0.169	0.188	0.147	0.139	0.153	0.180	0.168	0.175
IOWA SOUTHERN UTILITIES CO	0.571	0.222	0.230	0.245	0.230	0.218	0.222	0.136	0.171	0.174	0.163	0.206
KANSAS POWER & LIGHT	0.281	0.190	0.202	0.211	0.217	0.211	0.194	0.186	0.148	0.160	0.151	0.187
LAKE SUPERIOR DIST POWER CO	0.315	0.149	0.169	0.140	0.124	0.147	0.174	0.155	0.156	0.175	0.141	0.153
LONG ISLAND LIGHTING	0.530	0.178	0.171	0.188	0.168	0.167	0.143	0.129	0.115	0.146	0.154	0.156
LOUISVILLE GAS & ELECTRIC	0.436	0.247	0.263	0.267	0.240	0.223	0.198	0.183	0.155	0.155	0.184	0.216
MADISON GAS & ELECTRIC CO	0.367	0.118	0.122	0.140	0.117	0.128	0.119	0.160	0.138	0.157	0.171	0.141
MISSOURI PUBLIC SERVICE CO	0.631	0.215	0.194	0.194	0.201	0.161	0.186	0.144	0.173	0.190	0.216	0.187
MONTANA POWER CO	0.311	0.200	0.190	0.221	0.213	0.203	0.194	0.187	0.154	0.139	0.094	0.179
NEW ENGLAND GAS & ELECTRIC	0.529	0.178	0.160	0.146	0.138	0.158	0.144	0.126	0.121	0.116	0.172	0.146
NEW YORK STATE ELEC & GAS	0.534	0.178	0.168	0.140	0.120	0.094	0.117	0.123	0.124	0.114	0.127	0.131
NIAGARA MOHAWK POWER	0.490	0.153	0.115	0.115	0.094	0.100	0.120	0.074	0.091	0.130	0.098	0.109
NORTHERN INDIANA PUBLIC SERV	0.337	0.247	0.241	0.231	0.240	0.197	0.200	0.181	0.136	0.164	0.191	0.203
NORTHERN STATES POWER	0.477	0.199	0.202	0.157	0.179	0.176	0.190	0.151	0.144	0.152	0.192	0.182
NORTHWESTERN PUBLIC SERV CO	0.392	0.176	0.173	0.181	0.192	0.208	0.196	0.157	0.137	0.107	0.168	0.169
ORANGE & ROCKLAND UTILITIES	0.637	0.177	0.169	0.139	0.158	0.050	0.082	0.108	0.082	0.147	0.169	0.128
PACIFIC GAS & ELECTRIC	0.240	0.161	0.158	0.154	0.131	0.149	0.142	0.135	0.120	0.086	0.090	0.133
PACIFIC POWER & LIGHT	0.437	0.108	0.113	0.114	0.112	0.137	0.142	0.125	0.090	0.112	0.117	0.117
PHILADELPHIA ELECTRIC CO	0.438	0.175	0.154	0.143	0.113	0.137	0.134	0.125	0.114	0.127	0.130	0.135
PUBLIC SERVICE CO OF COLO	0.365	0.158	0.165	0.161	0.150	0.128	0.134	0.129	0.094	0.158	0.141	0.142
PUBLIC SERVICE ELEC & GAS	0.609	0.159	0.160	0.142	0.104	0.130	0.089	0.083	0.103	0.120	0.161	0.125
ROCHESTER GAS & ELECTRIC	0.606	0.170	0.143	0.128	0.109	0.106	0.112	0.151	0.087	0.120	0.127	0.126
ST JOSEPH LIGHT & POWER	0.599	0.179	0.209	0.175	0.187	0.220	0.205	0.158	0.148	0.154	0.153	0.179
SAN DIEGO GAS & ELECTRIC	0.511	0.165	0.169	0.178	0.147	0.129	0.090	0.081	0.110	0.042	0.125	0.124
SIERRA PACIFIC POWER CO	0.502	0.114	0.113	0.104	0.103	0.110	0.121	0.126	0.128	0.118	0.163	0.120
SOUTH CAROLINA ELEC & GAS	0.841	0.194	0.206	0.180	0.135	0.106	0.115	0.101	0.108	0.165	0.144	0.145
SOUTHERN INDIANA GAS & ELEC	0.445	0.218	0.231	0.232	0.227	0.214	0.236	0.236	0.197	0.158	0.213	0.220
TUCSON GAS & ELECTRIC	0.532	0.180	0.179	0.183	0.185	0.144	0.139	0.122	0.063	0.158	0.166	0.152
WASHINGTON WATER POWER	0.292	0.135	0.156	0.156	0.146	0.144	0.137	0.137	0.142	0.149	0.173	0.147
WISCONSIN ELECTRIC POWER	0.140	0.197	0.155	0.170	0.146	0.158	0.209	0.239	0.199	0.193	0.197	0.185
WISCONSIN POWER & LIGHT	0.419	0.225	0.234	0.224	0.213	0.177	0.178	0.180	0.163	0.233	0.264	0.209
WISCONSIN PUBLIC SERVICE	0.291	0.232	0.213	0.196	0.199	0.154	0.185	0.194	0.183	0.248	0.295	0.210
MONTANA-DAKOTA UTILITIES	0.262	0.150	0.167	0.170	0.174	0.160	0.156	0.119	0.129	0.153	0.179	0.156

TABLE NO. 14

RATE OF RETURN MEASURE 4

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
ALLEGHENY POWER SYSTEM	0.525	0.191	0.177	0.151	0.127	0.110	0.124	0.144	0.126	0.230	0.258	0.164
AMERICAN ELECTRIC POWER	0.516	0.173	0.157	0.118	0.089	0.073	0.067	0.105	0.043	0.237	0.248	0.131
ATLANTIC CITY ELECTRIC	0.555	0.187	0.188	0.160	0.110	0.078	0.101	0.158	0.217	0.303	0.323	0.182
BANGOR HYDRO-ELEC CO	0.524	0.210	0.168	0.165	0.128	0.111	0.169	0.102	0.124	0.193	0.081	0.147
BLACK HILLS POWER & LIGHT CO	0.428	0.143	0.143	0.122	0.122	0.171	0.170	0.179	0.225	0.257	0.372	0.191
BOSTON EDISON CO	0.525	0.156	0.157	0.133	0.095	0.043	0.018	0.078	0.103	0.131	0.114	0.102
BRASCAN LTD-CL A	0.614	0.068	0.068	0.065	0.065	0.073	0.072	0.086	0.061	0.043	0.047	0.065
CAROLINA POWER & LIGHT	0.609	0.173	0.187	0.151	0.052	0.076	0.121	0.098	[illegible]	[illegible]	0.654	[illegible] & 0.189
CENTRAL & SOUTH WEST CORP	0.388	0.212	0.223	0.234	0.213	0.199	0.213	0.239	0.246	0.233	[illegible]	0.222
CENTRAL MAINE POWER CO	0.310	0.191	0.185	0.172	0.166	0.139	0.174	0.156	0.123	0.155	0.182	0.164
CENTRAL VERMONT PUB SERV	0.766	0.158	0.111	0.077	0.030	0.018	0.059	-0.008	0.074	0.149	0.161	0.083
CLEVELAND ELECTRIC ILLUM	0.384	0.224	0.225	0.198	0.164	0.154	0.144	0.168	0.436	0.873	[illegible]	[illegible] 0.293
COLUMBUS & SOUTHERN OHIO	0.603	0.194	0.181	0.156	0.099	0.065	0.068	0.128	0.041	0.889	0.396	0.225
COMMONWEALTH EDISON	0.307	0.212	0.203	0.172	0.136	0.106	0.126	0.154	0.102	0.188	0.223	0.168
COMMUNITY PUBLIC SERVICE	0.435	0.158	0.173	0.186	0.184	0.185	0.200	0.192	0.143	0.151	0.186	0.176
CONCORD ELECTRIC CO	0.000	0.097	0.136	0.127	0.119	0.120	0.138	0.105	0.137	0.223	0.187	0.139
DETROIT EDISON CO	0.714	0.149	0.141	0.142	0.094	0.073	0.078	0.085	0.030	0.075	0.394	0.102
DUKE POWER CO	0.612	0.204	0.191	0.146	0.038	0.040	0.017	0.077	0.210	0.246	0.429	0.160
DUQUESNE LIGHT CO	0.504	0.231	0.222	0.174	0.103	0.139	0.116	0.150	0.276	0.275	0.184	0.197
EASTERN UTILITIES ASSOC	0.761	0.204	0.180	0.136	0.110	0.139	0.151	0.034	0.078	0.191	1.132	0.236
EDISON SAULT ELECTRIC	0.000	0.229	0.224	0.192	0.159	0.125	0.136	0.163	0.202	0.127	0.116	0.168
EL PASO ELECTRIC CO	0.358	0.228	0.230	0.243	0.226	0.213	0.219	0.219	0.270	0.245	0.225	0.232
EMPIRE DISTRICT ELECTRIC CO	0.326	0.207	0.215	0.172	0.186	0.169	0.160	0.152	0.149	0.158	0.171	0.174
FLORIDA POWER & LIGHT	0.575	0.187	0.203	0.194	0.171	0.155	0.124	0.193	0.222	0.658	0.212	0.236
FLORIDA POWER CORP	0.636	0.189	0.197	0.192	0.169	0.144	0.133	0.155	0.061	0.445	0.434	0.212
GENERAL PUBLIC UTILITIES	0.629	0.120	0.102	0.059	0.039	0.063	0.075	0.049	0.177	0.195	0.297	0.123
GREEN MOUNTAIN POWER CORP	1.063	0.155	0.126	0.095	0.055	-0.045	0.039	0.049	0.142	0.168	0.175	0.096
GULF STATES UTILITIES CO	0.434	0.207	0.201	0.183	0.159	0.144	0.156	0.161	0.253	0.261	0.283	0.203
HAWAIIAN ELECTRIC CO	0.477	0.140	0.156	0.157	0.137	0.128	0.118	0.132	0.136	0.166	0.161	0.143
IDAHO POWER CO	0.363	0.113	0.147	0.159	0.169	0.178	0.164	0.170	0.152	0.118	0.155	0.153
INDIANAPOLIS POWER & LIGHT	0.694	0.231	0.225	0.210	0.204	0.192	0.209	0.186	0.172	0.329	0.711	0.267
KANSAS CITY POWER & LIGHT	0.481	0.177	0.171	0.165	0.148	0.140	0.121	0.125	0.160	0.198	0.259	0.167
KANSAS GAS & ELECTRIC	0.556	0.210	0.220	0.231	0.199	0.159	0.120	0.143	0.145	0.317	1.111	0.284
KENTUCKY UTILITIES CO	0.465	0.203	0.201	0.196	0.155	0.141	0.129	0.132	0.146	0.231	0.214	0.180
MAINE PUBLIC SERVICE	0.491	0.143	0.133	0.153	0.153	0.123	0.136	0.171	0.199	0.157	0.181	0.155
MIDDLE SOUTH UTILITIES	0.417	0.156	0.175	0.183	0.168	0.148	0.144	0.198	0.207	0.204	0.368	0.195
MINNESOTA POWER & LIGHT	0.390	0.166	0.190	0.178	0.157	0.148	0.107	0.128	0.157	0.224	0.229	0.162
NEVADA POWER CO	0.650	0.143	0.152	0.146	0.103	0.104	0.129	0.106	[illegible]	[illegible]	0.147	[illegible] 0.129
NEW ENGLAND ELECTRIC SYSTEM	0.533	0.153	0.133	0.108	0.117	0.120	0.143	0.140	0.152	0.193	0.205	0.146
NORTHEAST UTILITIES	0.582	0.164	0.138	0.116	0.046	0.068	0.081	0.096	0.139	0.085	0.143	0.108
OHIO EDISON CO	0.432	0.230	0.224	0.218	0.173	0.136	0.129	0.194	0.344	[illegible]	[illegible]	[illegible] 0.206
OKLAHOMA GAS & ELECTRIC	0.342	0.220	0.218	0.248	0.242	0.226	0.218	0.244	0.251	0.253	0.267	0.239
OTTER TAIL POWER CO	0.281	0.171	0.151	0.166	0.172	0.206	0.186	0.278	4.234	0.362	0.212	0.614
PENNSYLVANIA POWER & LIGHT	0.441	0.181	0.158	0.130	0.068	0.084	0.120	0.167	0.329	0.356	0.391	0.199
PORTLAND GENERAL ELECTRIC CO	0.444	0.120	0.117	0.135	0.115	0.142	0.116	0.134	[illegible]	[illegible]	[illegible]	[illegible] 0.187
POTOMAC ELECTRIC POWER	0.460	0.144	0.133	0.095	0.094	0.095	0.127	0.163	0.337	0.168	0.299	0.168
PUBLIC SERVICE CO OF IND	0.423	0.203	0.214	0.204	0.187	0.152	0.183	0.240	0.320	0.297	0.326	0.233
PUBLIC SERVICE CO OF N H	0.564	0.147	0.173	0.181	0.146	0.104	0.092	0.094	0.127	0.195	0.184	0.144
PUBLIC SERVICE CO OF N MEX	0.592	0.205	0.186	0.181	0.185	0.164	0.171	0.133	0.170	0.274	0.255	0.201
PUGET SOUND POWER & LIGHT	0.476	0.090	0.094	0.087	0.080	0.085	0.105	0.107	0.219	0.216	0.176	0.126
SAVANNAH ELEC & POWER	0.537	0.160	0.181	0.162	0.127	0.075	0.066	0.059	0.140	0.279	0.191	0.144
SOUTHERN CALIF EDISON CO	0.382	0.136	0.115	0.103	0.108	0.096	0.106	0.118	0.253	0.160	0.183	0.138
SOUTHERN CO	0.504	0.167	0.171	0.175	0.142	0.095	0.088	0.145	0.109	0.528	0.286	0.191
SOUTHWESTERN ELEC SERVICE	0.371	0.178	0.181	0.207	0.217	0.210	0.209	0.211	0.209	0.204	0.189	0.202
SOUTHWESTERN PUBLIC SERV CO	0.374	0.194	0.209	0.227	0.230	0.226	0.206	0.234	0.306	0.312	0.333	0.248
TAMPA ELECTRIC CO	0.773	0.210	0.194	0.176	0.149	0.109	0.160	0.178	0.125	0.295	0.229	0.182
TEXAS UTILITIES CO	0.199	0.252	0.258	0.266	0.246	0.239	0.216	0.227	0.253	0.266	0.415	0.261
TOLEDO EDISON COMPANY	0.418	0.237	0.244	0.243	0.210	0.176	0.164	0.319	[illegible]	[illegible]	[illegible]	[illegible] 0.228
UNION ELECTRIC CO	0.400	0.154	0.148	0.138	0.134	0.081	0.059	0.107	0.103	0.257	0.321	0.150
UNITED ILLUMINATING CO	0.412	0.182	0.154	0.201	0.173	0.104	0.202	0.146	2.526	0.143	0.112	0.394
UPPER PENINSULA POWER	0.440	0.165	0.162	0.156	0.121	0.119	0.174	0.172	0.088	0.114	0.185	0.146
UTAH POWER & LIGHT	0.344	0.149	0.141	0.135	0.114	0.106	0.131	0.125	0.105	0.152	0.291	0.145
VIRGINIA ELECTRIC & POWER	0.617	0.189	0.175	0.149	0.108	0.055	0.033	0.086	0.054	0.381	0.515	0.175
ARIZONA PUBLIC SERVICE CO	0.491	0.098	0.104	0.122	0.139	0.115	0.106	0.149	0.164	0.374	0.284	0.166
BALTIMORE GAS & ELECTRIC	0.420	0.240	0.243	0.223	0.174	0.133	0.095	0.180	1.640	0.492	0.261	0.368
CENTRAL HUDSON GAS & ELEC	0.480	0.151	0.165	0.146	0.075	0.134	0.138	0.169	0.060	0.161	0.184	0.138
CENTRAL ILLINOIS LIGHT	0.487	0.174	0.177	0.187	0.191	0.158	0.153	0.163	0.196	0.376	0.231	0.201
CENTRAL ILL PUBLIC SERVICE	0.567	0.242	0.243	0.235	0.197	0.171	0.132	0.149	0.179	0.234	0.251	0.203
CINCINNATI GAS & ELECTRIC	0.284	0.249	0.245	0.225	0.185	0.157	0.172	0.210	0.192	0.177	0.184	0.200
CONSOLIDATED EDISON OF N.Y.	0.302	0.094	0.091	0.077	0.041	0.047	0.036	0.063	0.122	0.143	0.169	0.088
CONSUMERS POWER CO	0.711	0.193	0.178	0.158	0.138	0.095	0.087	0.101	0.055	0.149	0.206	0.136
DAYTON POWER & LIGHT	0.479	0.269	0.218	0.186	0.132	0.135	0.121	0.103	0.118	0.249	0.254	0.178
DELMARVA POWER & LIGHT	0.472	0.201	0.206	0.175	0.111	0.096	0.079	0.112	0.180	0.106	0.089	0.134
FITCHBURG GAS & ELEC LIGHT	0.397	0.131	0.149	0.125	0.114	0.111	0.119	0.096	0.067	0.111	0.150	0.117
ILLINOIS POWER CO	0.497	0.270	0.265	0.248	0.223	0.173	0.145	0.168	0.181	0.225	0.197	0.209
INTERSTATE POWER CO	0.436	0.190	0.198	0.207	0.184	0.189	0.190	0.203	0.213	0.283	0.538	0.239
IOWA ELECTRIC LIGHT & PWR	0.713	0.160	0.166	0.164	0.143	0.055	0.106	0.106	-0.025	0.118	0.148	0.118
IOWA-ILLINOIS GAS & ELEC	0.734	0.205	0.190	0.162	0.115	0.082	0.160	0.163	0.181	0.196	0.211	0.169
IOWA POWER & LIGHT	0.353	0.205	0.195	0.181	0.139	0.159	0.148	0.212	0.187	0.241	0.247	0.191
IOWA PUBLIC SERVICE CO	0.304	0.199	0.210	0.189	0.154	0.162	0.128	0.144	0.181	0.205	0.206	0.178
IOWA SOUTHERN UTILITIES CO	0.571	0.200	0.214	0.243	0.228	0.217	0.218	0.239	0.261	0.204	0.175	0.217
KANSAS POWER & LIGHT	0.281	0.187	0.200	0.204	0.198	0.199	0.194	0.187	0.144	0.174	0.232	0.192
LAKE SUPERIOR DIST POWER CO	0.315	0.149	0.165	0.135	0.123	0.147	0.170	0.181	0.200	0.185	0.147	0.163
LONG ISLAND LIGHTING	0.530	0.166	0.162	0.181	0.152	0.143	0.118	0.142	0.202	0.663	[illegible]	[illegible] 0.187
LOUISVILLE GAS & ELECTRIC	0.436	0.247	0.263	0.267	0.240	0.223	0.198	0.217	0.186	0.261	0.333	0.244
MADISON GAS & ELECTRIC CO	0.367	0.115	0.119	0.131	0.100	0.088	0.070	0.221	0.709	0.300	0.221	0.207
MISSOURI PUBLIC SERVICE CO	0.631	0.184	0.126	0.129	0.192	0.153	0.175	0.142	0.182	0.203	0.226	0.171
MONTANA POWER CO	0.311	0.195	0.183	0.218	0.213	0.201	0.191	0.198	0.184	0.164	0.096	0.184
NEW ENGLAND GAS & ELECTRIC	0.529	0.149	0.139	0.139	0.129	0.145	0.136	0.134	0.141	0.139	0.218	0.147
NEW YORK STATE ELEC & GAS	0.534	0.172	0.149	0.109	0.105	0.087	0.109	0.129	0.154	0.152	0.232	0.140
NIAGARA MOHAWK POWER	0.490	0.140	0.095	0.093	0.077	0.089	0.096	0.063	0.111	0.181	0.122	0.107
NORTHERN INDIANA PUBLIC SERV	0.337	0.237	0.230	0.224	0.230	0.188	0.179	0.216	0.223	0.267	0.254	0.225
NORTHERN STATES POWER	0.477	0.182	0.167	0.173	0.147	0.133	0.143	0.133	0.186	0.291	0.263	0.194
NORTHWESTERN PUBLIC SERV CO	0.392	0.174	0.170	0.179	0.189	0.200	0.175	0.240	1.457	0.380	0.206	0.337
ORANGE & ROCKLAND UTILITIES	0.637	0.171	0.148	0.122	0.141	0.020	0.048	0.112	0.091	0.155	0.183	0.119
PACIFIC GAS & ELECTRIC	0.240	0.149	0.151	0.147	0.119	0.133	0.120	0.138	0.154	0.098	0.108	0.132
PACIFIC POWER & LIGHT	0.487	0.106	0.109	0.108	0.053	0.103	0.137	0.132	0.111	0.135	0.146	0.115
PHILADELPHIA ELECTRIC CO	0.438	0.166	0.146	0.130	0.086	0.095	0.086	0.139	0.303	0.303	0.344	0.180
PUBLIC SERVICE CO OF COLO	0.365	0.149	0.152	0.157	0.139	0.110	0.108	0.118	0.120	0.219	0.191	0.146
PUBLIC SERVICE ELEC & GAS	0.609	0.152	0.149	0.130	0.081	0.096	0.049	0.058	0.146	0.182	0.316	0.136
ROCHESTER GAS & ELECTRIC	0.606	0.159	0.122	0.091	0.089	0.104	0.109	0.159	0.092	0.140	0.160	0.122
ST JOSEPH LIGHT & POWER	0.599	0.168	0.190	0.160	0.184	0.219	0.195	0.170	0.192	0.192	0.199	0.187
SAN DIEGO GAS & ELECTRIC	0.511	0.162	0.166	0.174	0.142	0.117	0.080	0.072	0.125	0.023	0.213	0.127
SIERRA PACIFIC POWER CO	0.502	0.105	0.098	0.100	0.093	0.095	0.114	0.132	0.127	0.119	0.173	0.116
SOUTH CAROLINA ELEC & GAS	0.341	0.186	0.197	0.157	0.098	0.078	0.089	0.083	0.124	0.256	0.361	0.163
SOUTHERN INDIANA GAS & ELEC	0.445	0.217	0.228	0.218	0.209	0.197	0.199	0.222	0.209	0.210	0.240	0.215
TUCSON GAS & ELECTRIC	0.532	0.169	0.172	0.170	0.176	0.124	0.097	0.118	-0.072	0.295	0.304	0.155
WASHINGTON WATER POWER	0.232	0.135	0.151	0.152	0.138	0.131	0.120	0.137	0.145	0.153	0.185	0.145
WISCONSIN ELECTRIC POWER	0.140	0.187	0.155	0.165	0.123	0.144	0.137	0.242	0.212	0.213	0.213	0.185
WISCONSIN POWER & LIGHT	0.419	0.223	0.226	0.200	0.199	0.147	0.138	0.236	0.327	0.329	0.340	0.236
WISCONSIN PUBLIC SERVICE	0.291	0.229	0.203	0.174	0.179	0.119	0.145	0.259	0.348	0.325	0.344	0.232
MONTANA-DAKOTA UTILITIES	0.262	0.149	0.165	0.170	0.170	0.157	0.150	0.110	0.112	0.142	0.176	0.150

TABLE NO. 45

RATE OF RETURN MEASURE 5

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
ALLEGHENY POWER SYSTEM	0.525	0.191	0.177	0.151	0.127	0.110	0.124	0.135	0.113	0.203	0.210	0.154
AMERICAN ELECTRIC POWER	0.516	0.173	0.157	0.118	0.089	0.073	0.067	0.068	0.013	0.094	0.133	0.099
ATLANTIC CITY ELECTRIC	0.555	0.187	0.188	0.160	0.110	0.078	0.101	0.098	0.081	0.160	0.170	0.133
BANGOR HYDRO-ELEC CO	0.524	0.210	0.188	0.165	0.128	0.111	0.169	0.100	0.120	0.175	0.067	0.143
BLACK HILLS POWER & LIGHT CO	0.429	0.143	0.143	0.122	0.122	0.171	0.170	0.172	0.175	0.151	0.154	0.153
BOSTON EDISON CO	0.525	0.156	0.157	0.133	0.085	0.048	0.018	0.068	0.068	0.098	0.099	0.093
BRASCAN LTD-CL A	0.614	0.068	0.068	0.065	0.065	0.073	0.072	0.086	0.061	0.043	0.047	0.065
CAROLINA POWER & LIGHT	0.609	0.173	0.187	0.151	0.052	0.076	0.121	0.054	-0.010	0.122	0.193	0.112
CENTRAL & SOUTH WEST CORP	0.388	0.212	0.223	0.234	0.213	0.199	0.213	0.217	0.209	0.198	0.172	0.209
CENTRAL MAINE POWER CO	0.310	0.191	0.185	0.172	0.166	0.139	0.174	0.153	0.116	0.133	0.133	0.156
CENTRAL VERMONT PUB SERV	0.766	0.158	0.111	0.077	0.030	0.018	0.059	-0.008	0.069	0.133	0.137	0.079
CLEVELAND ELECTRIC ILLUM	0.384	0.224	0.225	0.198	0.164	0.154	0.144	0.132	0.176	0.118	0.128	0.166
COLUMBUS & SOUTHERN OHIO	0.603	0.194	0.181	0.156	0.098	0.069	0.088	0.106	0.024	0.178	0.116	0.121
COMMONWEALTH EDISON	0.307	0.212	0.203	0.172	0.136	0.106	0.126	0.137	0.127	0.141	0.142	0.150
COMMUNITY PUBLIC SERVICE	0.435	0.158	0.173	0.186	0.184	0.185	0.200	0.191	0.142	0.150	0.179	0.175
CONCORD ELECTRIC CO	0.000	0.097	0.136	0.127	0.119	0.120	0.139	0.102	0.132	0.219	0.186	0.138
DETROIT EDISON CO	0.714	0.149	0.141	0.142	0.094	0.073	0.078	0.073	0.057	0.060	0.062	0.093
DUKE POWER CO	0.612	0.204	0.191	0.146	0.038	0.040	0.017	0.047	0.072	0.126	0.181	0.106
DUQUESNE LIGHT CO	0.504	0.231	0.222	0.174	0.103	0.139	0.116	0.107	0.114	0.146	0.106	0.146
EASTERN UTILITIES ASSOC	0.761	0.204	0.180	0.136	0.110	0.139	0.151	0.026	0.036	0.032	0.199	0.122
EDISON SAULT ELECTRIC	0.000	0.229	0.224	0.192	0.159	0.129	0.136	0.166	0.198	0.125	0.116	0.167
EL PASO ELECTRIC CO	0.358	0.228	0.230	0.243	0.226	0.213	0.219	0.213	0.206	0.180	0.193	0.215
EMPIRE DISTRICT ELECTRIC CO	0.326	0.207	0.215	0.172	0.186	0.169	0.160	0.151	0.147	0.156	0.166	0.173
FLORIDA POWER & LIGHT	0.575	0.187	0.203	0.194	0.171	0.155	0.124	0.163	0.120	0.221	0.108	0.165
FLORIDA POWER CORP	0.636	0.189	0.197	0.192	0.165	0.144	0.133	0.094	0.014	0.146	0.157	0.143
GENERAL PUBLIC UTILITIES	0.629	0.120	0.102	0.059	0.039	0.063	0.075	0.067	0.080	0.102	0.133	0.084
GREEN MOUNTAIN POWER CORP	1.063	0.155	0.126	0.095	0.055	-0.045	0.039	0.048	0.134	0.157	0.167	0.093
GULF STATES UTILITIES CO	0.484	0.207	0.201	0.183	0.159	0.144	0.156	0.158	0.174	0.143	0.133	0.166
HAWAIIAN ELECTRIC CO	0.477	0.140	0.156	0.157	0.137	0.128	0.118	0.123	0.122	0.155	0.152	0.139
IDAHO POWER CO	0.363	0.113	0.147	0.159	0.169	0.178	0.164	0.129	0.117	0.112	0.143	0.143
INDIANAPOLIS POWER & LIGHT	0.694	0.231	0.225	0.210	0.204	0.192	0.209	0.176	0.131	0.156	0.171	0.190
KANSAS CITY POWER & LIGHT	0.481	0.177	0.171	0.165	0.148	0.140	0.121	0.121	0.145	0.147	0.151	0.149
KANSAS GAS & ELECTRIC	0.558	0.210	0.220	0.231	0.199	0.158	0.120	0.119	0.140	0.165	0.170	0.174
KENTUCKY UTILITIES CO	0.465	0.203	0.201	0.196	0.155	0.141	0.129	0.142	0.107	0.189	0.148	0.161
MAINE PUBLIC SERVICE	0.491	0.143	0.133	0.153	0.153	0.123	0.136	0.171	0.199	0.157	0.181	0.155
MIDDLE SOUTH UTILITIES	0.417	0.156	0.175	0.183	0.168	0.148	0.144	0.144	0.103	0.100	0.112	0.143
MINNESOTA POWER & LIGHT	0.390	0.166	0.190	0.179	0.157	0.148	0.107	0.125	0.145	0.157	0.183	0.160
NEVADA POWER CO	0.650	0.143	0.152	0.146	0.103	0.104	0.129	0.060	0.033	-0.036	0.088	0.092
NEW ENGLAND ELECTRIC SYSTEM	0.533	0.153	0.133	0.108	0.117	0.120	0.143	0.113	0.116	0.171	0.175	0.135
NORTHEAST UTILITIES	0.582	0.164	0.138	0.116	0.046	0.068	0.081	0.075	0.064	0.051	0.103	0.091
OHIO EDISON CO	0.432	0.230	0.224	0.218	0.173	0.136	0.129	0.140	0.064	0.072	0.095	0.147
OKLAHOMA GAS & ELECTRIC	0.342	0.220	0.213	0.248	0.242	0.226	0.218	0.224	0.195	0.175	0.136	0.210
OTTER TAIL POWER CO	0.281	0.171	0.151	0.166	0.172	0.206	0.186	0.179	0.123	0.159	0.189	0.170
PENNSYLVANIA POWER & LIGHT	0.441	0.181	0.158	0.130	0.068	0.084	0.120	0.140	0.173	0.150	0.122	0.133
PORTLAND GENERAL ELECTRIC CO	0.444	0.120	0.117	0.135	0.115	0.142	0.116	0.075	0.055	0.094	0.124	0.110
POTOMAC ELECTRIC POWER	0.460	0.144	0.133	0.095	0.094	0.095	0.127	0.152	0.179	0.088	0.189	0.130
PUBLIC SERVICE CO OF IND	0.423	0.203	0.214	0.204	0.187	0.152	0.183	0.206	0.200	0.188	0.239	0.198
PUBLIC SERVICE CO OF N H	0.564	0.147	0.173	0.181	0.146	0.104	0.092	0.067	0.087	0.164	0.126	0.129
PUBLIC SERVICE CO OF N MEX	0.592	0.205	0.186	0.181	0.135	0.168	0.171	0.173	0.142	0.172	0.125	0.171
PUGET SOUND POWER & LIGHT	0.476	0.090	0.094	0.087	0.080	0.085	0.105	0.098	0.146	0.122	0.128	0.103
SAVANNAH ELEC & POWER	0.537	0.160	0.181	0.162	0.127	0.075	0.066	0.046	0.055	0.103	0.084	0.106
SOUTHERN CALIF EDISON CO	0.382	0.136	0.115	0.103	0.108	0.096	0.106	0.109	0.207	0.121	0.120	0.122
SOUTHERN CO	0.504	0.167	0.171	0.175	0.142	0.095	0.088	0.102	0.032	0.163	0.106	0.124
SOUTHWESTERN ELEC SERVICE	0.371	0.178	0.181	0.207	0.217	0.210	0.209	0.211	0.208	0.203	0.183	0.201
SOUTHWESTERN PUBLIC SERV CO	0.374	0.194	0.209	0.227	0.230	0.226	0.206	0.212	0.252	0.222	0.237	0.222
TAMPA ELECTRIC CO	0.773	0.210	0.194	0.176	0.149	0.109	0.160	0.158	0.088	0.181	0.187	0.161
TEXAS UTILITIES CO	0.199	0.252	0.258	0.266	0.246	0.208	0.216	0.206	0.200	0.179	0.195	0.222
TOLEDO EDISON COMPANY	0.418	0.237	0.244	0.243	0.210	0.176	0.164	0.135	0.047	0.133	0.103	0.169
UNION ELECTRIC CO	0.400	0.154	0.148	0.138	0.134	0.081	0.059	0.095	0.070	0.141	0.198	0.122
UNITED ILLUMINATING CO	0.412	0.182	0.154	0.201	0.173	0.104	0.202	0.096	0.109	0.074	0.090	0.138
UPPER PENINSULA POWER	0.440	0.165	0.162	0.156	0.121	0.119	0.174	0.170	0.083	0.106	0.180	0.144
UTAH POWER & LIGHT	0.344	0.149	0.141	0.135	0.114	0.106	0.131	0.100	0.080	0.118	0.159	0.123
VIRGINIA ELECTRIC & POWER	0.617	0.189	0.175	0.149	0.108	0.055	0.033	0.060	0.016	0.092	0.094	0.097
ARIZONA PUBLIC SERVICE CO	0.491	0.098	0.104	0.122	0.139	0.115	0.106	0.118	0.083	0.135	0.091	0.111
BALTIMORE GAS & ELECTRIC	0.420	0.240	0.243	0.223	0.174	0.133	0.035	0.115	0.058	0.133	0.149	0.157
CENTRAL HUDSON GAS & ELEC	0.480	0.151	0.165	0.146	0.075	0.134	0.138	0.115	0.038	0.139	0.152	0.125
CENTRAL ILLINOIS LIGHT	0.487	0.174	0.177	0.187	0.191	0.158	0.153	0.137	0.100	0.095	0.148	0.152
CENTRAL ILL PUBLIC SERVICE	0.567	0.242	0.243	0.235	0.197	0.171	0.132	0.141	0.141	0.151	0.135	0.179
CINCINNATI GAS & ELECTRIC	0.234	0.249	0.245	0.225	0.185	0.157	0.172	0.176	0.125	0.115	0.109	0.176
CONSOLIDATED EDISON OF N.Y.	0.802	0.094	0.091	0.077	0.041	0.047	0.036	0.051	0.036	0.122	0.154	0.080
CONSUMERS POWER CO	0.711	0.193	0.178	0.158	0.138	0.095	0.087	0.089	0.039	0.104	0.143	0.122
DAYTON POWER & LIGHT	0.479	0.269	0.218	0.186	0.132	0.135	0.121	0.087	0.078	0.159	0.150	0.153
DELMARVA POWER & LIGHT	0.472	0.201	0.206	0.175	0.111	0.036	0.079	0.086	0.101	0.074	0.066	0.118
FITCHBURG GAS & ELEC LIGHT	0.387	0.131	0.149	0.125	0.114	0.111	0.119	0.083	0.043	0.087	0.137	0.110
ILLINOIS POWER CO	0.497	0.270	0.265	0.248	0.223	0.173	0.145	0.153	0.140	0.182	0.153	0.195
INTERSTATE POWER CO	0.436	0.190	0.198	0.207	0.194	0.189	0.190	0.195	0.197	0.180	0.132	0.185
IOWA ELECTRIC LIGHT & PWR	0.713	0.160	0.166	0.164	0.143	0.095	0.106	0.032	-0.005	0.115	0.146	0.112
IOWA-ILLINOIS GAS & ELEC	0.734	0.205	0.190	0.162	0.115	0.082	0.180	0.154	0.156	0.170	0.181	0.160
IOWA POWER & LIGHT	0.353	0.205	0.195	0.181	0.139	0.159	0.148	0.191	0.150	0.197	0.183	0.175
IOWA PUBLIC SERVICE CO	0.304	0.199	0.210	0.189	0.154	0.162	0.128	0.137	0.150	0.169	0.164	0.166
IOWA SOUTHERN UTILITIES CO	0.571	0.200	0.214	0.243	0.228	0.217	0.218	0.192	0.182	0.161	0.166	0.202
KANSAS POWER & LIGHT	0.281	0.187	0.200	0.204	0.198	0.199	0.194	0.187	0.144	0.159	0.147	0.182
LAKE SUPERIOR DIST POWER CO	0.315	0.149	0.165	0.135	0.123	0.147	0.170	0.162	0.172	0.179	0.143	0.155
LONG ISLAND LIGHTING	0.530	0.166	0.162	0.181	0.152	0.143	0.118	0.117	0.092	0.107	0.117	0.135
LOUISVILLE GAS & ELECTRIC	0.436	0.247	0.263	0.267	0.240	0.223	0.198	0.200	0.167	0.219	0.224	0.225
MADISON GAS & ELECTRIC CO	0.367	0.115	0.119	0.131	0.100	0.088	0.070	0.131	0.124	0.211	0.180	0.127
MISSOURI PUBLIC SERVICE CO	0.631	0.184	0.126	0.129	0.192	0.153	0.175	0.139	0.171	0.191	0.218	0.168
MONTANA POWER CO	0.311	0.195	0.183	0.218	0.213	0.201	0.191	0.189	0.155	0.130	0.087	0.176
NEW ENGLAND GAS & ELECTRIC	0.529	0.149	0.139	0.139	0.129	0.149	0.136	0.121	0.108	0.097	0.181	0.135
NEW YORK STATE ELEC & GAS	0.534	0.172	0.149	0.109	0.105	0.087	0.109	0.119	0.122	0.100	0.115	0.119
NIAGARA MOHAWK POWER	0.490	0.140	0.095	0.093	0.077	0.089	0.096	0.049	0.066	0.115	0.088	0.091
NORTHERN INDIANA PUBLIC SERV	0.337	0.237	0.230	0.224	0.230	0.188	0.179	0.164	0.124	0.152	0.169	0.190
NORTHERN STATES POWER	0.477	0.182	0.187	0.173	0.147	0.133	0.143	0.108	0.124	0.190	0.196	0.158
NORTHWESTERN PUBLIC SERV CO	0.392	0.174	0.170	0.179	0.189	0.200	0.175	0.135	0.080	0.078	0.164	0.154
ORANGE & ROCKLAND UTILITIES	0.637	0.171	0.148	0.122	0.141	0.020	0.048	0.097	0.076	0.142	0.166	0.113
PACIFIC GAS & ELECTRIC	0.240	0.149	0.151	0.147	0.119	0.133	0.120	0.120	0.108	0.065	0.071	0.118
PACIFIC POWER & LIGHT	0.487	0.106	0.109	0.108	0.093	0.103	0.107	0.113	0.066	0.077	0.103	0.099
PHILADELPHIA ELECTRIC CO	0.438	0.166	0.146	0.130	0.086	0.095	0.086	0.084	0.074	0.100	0.106	0.107
PUBLIC SERVICE CO OF COLO	0.365	0.149	0.152	0.157	0.139	0.110	0.108	0.103	0.083	0.151	0.140	0.129
PUBLIC SERVICE ELEC & GAS	0.609	0.152	0.149	0.130	0.081	0.096	0.049	0.043	0.079	0.111	0.171	0.106
ROCHESTER GAS & ELECTRIC	0.606	0.159	0.122	0.091	0.089	0.104	0.109	0.152	0.083	0.116	0.114	0.114
ST JOSEPH LIGHT & POWER	0.599	0.168	0.190	0.160	0.184	0.219	0.195	0.145	0.154	0.157	0.148	0.172
SAN DIEGO GAS & ELECTRIC	0.511	0.162	0.166	0.174	0.142	0.117	0.080	0.067	0.104	0.016	0.105	0.113
SIERRA PACIFIC POWER CO	0.502	0.105	0.098	0.100	0.093	0.095	0.114	0.116	0.106	0.111	0.158	0.110
SOUTH CAROLINA ELEC & GAS	0.841	0.186	0.197	0.157	0.098	0.078	0.089	0.079	0.101	0.160	0.126	0.127
SOUTHERN INDIANA GAS & ELEC	0.445	0.217	0.228	0.218	0.209	0.197	0.199	0.215	0.230	0.201	0.218	0.210
TUCSON GAS & ELECTRIC	0.532	0.169	0.172	0.170	0.176	0.124	0.097	0.064	-0.020	0.159	0.173	0.128
WASHINGTON WATER POWER	0.282	0.135	0.151	0.152	0.138	0.131	0.120	0.135	0.139	0.146	0.170	0.142
WISCONSIN ELECTRIC POWER	0.140	0.137	0.155	0.155	0.123	0.144	0.197	0.238	0.203	0.201	0.206	0.181
WISCONSIN POWER & LIGHT	0.419	0.223	0.226	0.200	0.199	0.147	0.138	0.161	0.163	0.262	0.288	0.201
WISCONSIN PUBLIC SERVICE	0.291	0.229	0.203	0.174	0.179	0.119	0.145	0.175	0.190	0.273	0.314	0.200
MONTANA-DAKOTA UTILITIES	0.262	0.149	0.165	0.170	0.170	0.157	0.150	0.110	0.112	0.142	0.176	0.150

APPENDIX 2

Ten-Year Returns for Low Barrier-To-Entry Group

TABLE NO. 2.1

RATE OF RETURN MEASURE 1

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
~~[illegible]~~	~~0.673~~	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
OWENS-ILLINOIS INC	0.618	0.088	0.107	0.128	0.116	0.097	0.094	0.100	0.103	0.096	0.103	0.103
ANCHOR HOCKING CORP	0.736	0.146	0.220	0.258	0.206	0.189	0.185	0.152	0.122	0.138	0.155	0.177
GOODYEAR TIRE & RUBBER CO	0.703	0.126	0.146	0.138	0.107	0.130	0.129	0.122	0.112	0.106	0.089	0.121
FIRESTONE TIRE & RUBBER CO	0.734	0.138	0.158	0.134	0.102	0.113	0.120	0.124	0.118	0.099	0.092	0.119
UNITED BANKS OF COLORADO	0.572	0.031	0.032	0.034	0.035	0.034	0.035	0.040	0.049	0.039	0.039	0.037
GOODRICH (B.F.) CO	0.793	0.068	0.100	0.085	0.049	0.074	0.093	0.100	0.086	0.055	0.049	0.076
INTERCO INC	0.953	0.132	0.159	0.150	0.150	0.148	0.174	0.185	0.198	0.214	0.209	0.172
BROWN GROUP INC	0.735	0.230	0.242	0.186	0.180	0.180	0.168	0.166	0.125	0.057	0.152	0.173
U S SHOE CORP	0.942	0.160	0.191	0.162	0.134	0.128	0.138	0.127	0.128	0.132	0.212	0.151
GENESCO INC	1.373	0.145	0.164	0.148	0.121	0.111	0.071	0.078	0.105	0.030	0.105	0.108
CELANESE CORP	0.561	0.082	0.103	0.111	0.072	0.089	0.075	0.107	0.116	0.061	0.083	0.090
U S GYPSUM CO	0.830	0.126	0.128	0.108	0.068	0.123	0.148	0.141	0.086	0.077	0.099	0.110
NATIONAL GYPSUM CO	0.839	0.086	0.104	0.101	0.063	0.096	0.132	0.131	0.108	0.082	0.106	0.101
CPC INTL INC	0.517	0.143	0.152	0.151	0.147	0.123	0.141	0.152	0.164	0.166	0.184	0.154
STOKELY-VAN CAMP INC	0.634	0.113	0.091	0.092	0.101	0.097	0.114	0.122	0.131	0.103	0.081	0.105
ESMARK INC	0.473	0.073	0.050	0.069	0.089	0.087	0.084	0.102	0.128	0.129	0.103	0.091
GENERAL MILLS INC	0.603	0.161	0.156	0.158	0.153	0.157	0.177	0.178	0.158	0.181	0.184	0.166
PILLSBURY CO	0.717	0.122	0.125	0.149	0.099	0.112	0.117	0.121	0.127	0.153	0.142	0.127
AMERICAN CAN CO	0.313	0.135	0.129	0.108	0.111	0.092	0.085	0.101	0.126	0.096	0.112	0.109
CONTINENTAL GROUP	0.317	0.155	0.168	0.175	0.148	0.106	0.108	0.122	0.137	0.106	0.113	0.134
ANHEUSER-BUSCH INC	0.534	0.171	0.200	0.186	0.221	0.227	0.226	0.180	0.157	0.176	0.106	0.185
PABST BREWING CO	0.562	0.221	0.247	0.197	0.189	0.209	0.204	0.153	0.104	0.122	0.177	0.182
COORS (ADOLPH) CO	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.433	0.245	0.068
SCHLITZ (JOSEPH) BREWING	0.841	0.179	0.209	0.213	0.214	0.215	0.241	0.263	0.195	0.122	0.162	0.202
AMERICAN BAKERIES CO	0.871	0.093	0.063	-0.019	0.064	0.007	0.017	-0.032	-0.009	0.069	0.090	0.036
BURLINGTON INDUSTRIES INC	0.889	0.122	0.166	0.149	0.129	0.081	0.086	0.125	0.133	0.067	0.133	0.119
STEVENS (J.P.) & CO	0.740	0.079	0.119	0.102	0.037	0.016	0.059	0.107	0.129	0.072	0.115	0.083
CONE MILLS CORP	0.744	0.067	0.045	0.052	0.068	0.081	0.087	0.091	0.140	0.174	0.223	0.103
DAN RIVER INC	0.912	0.069	0.071	0.032	0.020	0.010	0.050	0.095	0.075	0.009	0.106	0.054

TABLE NO. 2.2

RATE OF RETURN MEASURE 2

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
~~[illegible]~~	~~0.673~~	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	-0.007	0.065	0.080
OWENS-ILLINOIS INC	0.618	0.088	0.107	0.130	0.119	0.100	0.097	0.102	0.108	0.101	0.107	0.106
ANCHOR HOCKING CORP	0.736	0.146	0.220	0.258	0.206	0.189	0.185	0.152	0.122	0.138	0.155	0.177
GOODYEAR TIRE & RUBBER CO	0.703	0.126	0.146	0.142	0.113	0.136	0.136	0.128	0.117	0.111	0.093	0.125
FIRESTONE TIRE & RUBBER CO	0.734	0.138	0.158	0.134	0.102	0.113	0.120	0.124	0.118	0.099	0.082	0.119
UNITED BANKS OF COLORADO	0.572	0.031	0.032	0.034	0.035	0.034	0.035	0.040	0.049	0.039	0.039	0.037
GOODRICH (B.F.) CO	0.793	0.068	0.100	0.087	0.051	0.076	0.094	0.100	0.086	0.055	0.049	0.077
INTERCO INC	0.953	0.132	0.159	0.150	0.150	0.148	0.174	0.185	0.198	0.215	0.210	0.172
BROWN GROUP INC	0.735	0.230	0.242	0.186	0.180	0.190	0.169	0.166	0.125	0.057	0.152	0.173
U S SHOE CORP	0.942	0.160	0.191	0.162	0.134	0.129	0.139	0.128	0.128	0.133	0.212	0.152
GENESCO INC	1.373	0.145	0.164	0.148	0.122	0.112	0.072	0.078	0.105	0.030	0.105	0.108
CELANESE CORP	0.561	0.082	0.103	0.114	0.076	0.093	0.079	0.112	0.123	0.065	0.089	0.094
U S GYPSUM CO	0.830	0.126	0.129	0.111	0.071	0.127	0.154	0.144	0.086	0.077	0.099	0.112
NATIONAL GYPSUM CO	0.839	0.086	0.104	0.101	0.063	0.096	0.134	0.132	0.108	0.082	0.106	0.101
CPC INTL INC	0.517	0.143	0.152	0.153	0.153	0.127	0.146	0.157	0.172	0.198	0.196	0.160
STOKELY-VAN CAMP INC	0.634	0.113	0.091	0.093	0.102	0.098	0.115	0.123	0.133	0.104	0.082	0.105
ESMARK INC	0.473	0.073	0.050	0.069	0.089	0.087	0.084	0.103	0.131	0.135	0.107	0.093
GENERAL MILLS INC	0.603	0.161	0.156	0.158	0.153	0.157	0.177	0.178	0.161	0.189	0.191	0.168
PILLSBURY CO	0.717	0.122	0.125	0.149	0.099	0.112	0.117	0.121	0.127	0.153	0.142	0.127
AMERICAN CAN CO	0.313	0.135	0.129	0.109	0.114	0.084	0.086	0.103	0.129	0.099	0.115	0.110
CONTINENTAL GROUP	0.317	0.155	0.168	0.181	0.157	0.113	0.118	0.131	0.144	0.112	0.123	0.140
ANHEUSER-BUSCH INC	0.534	0.171	0.200	0.196	0.243	0.245	0.246	0.199	0.173	0.156	0.114	0.198
PABST BREWING CO	0.562	0.221	0.247	0.214	0.204	0.210	0.208	0.159	0.107	0.125	0.183	0.188
COORS (ADOLPH) CO	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.498	0.273	0.077
SCHLITZ (JOSEPH) BREWING	0.841	0.179	0.209	0.220	0.241	0.234	0.245	0.272	0.228	0.151	0.182	0.216
AMERICAN BAKERIES CO	0.871	0.093	0.063	-0.019	0.065	0.008	0.018	-0.033	-0.009	0.090	0.092	0.037
BURLINGTON INDUSTRIES INC	0.889	0.122	0.166	0.151	0.132	0.082	0.088	0.127	0.135	0.069	0.135	0.121
STEVENS (J.P.) & CO	0.740	0.079	0.119	0.102	0.037	0.016	0.060	0.108	0.131	0.073	0.116	0.084
CONE MILLS CORP	0.744	0.067	0.045	0.052	0.068	0.081	0.087	0.091	0.140	0.174	0.223	0.103
DAN RIVER INC	0.912	0.069	0.071	0.033	0.020	0.010	0.050	0.096	0.077	0.009	0.108	0.054

TABLE NO. 23

RATE OF RETURN MEASURE 3

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
~~[illegible]~~	~~0.678~~	~~0.105~~	~~0.167~~	~~0.215~~	~~[illegible]~~	~~0.152~~	~~[illegible]~~	~~[illegible]~~	~~[illegible]~~	~~[illegible]~~	~~[illegible]~~	~~[illegible]~~
OWENS-ILLINOIS INC	0.613	0.131	0.170	0.213	0.189	0.150	0.146	0.155	0.161	0.145	0.156	0.162
ANCHOR HOCKING CORP	0.736	0.210	0.314	0.365	0.280	0.249	0.242	0.197	0.157	0.193	0.230	0.244
GOODYEAR TIRE & RUBBER CO	0.703	0.204	0.247	0.235	0.171	0.218	0.215	0.190	0.159	0.159	0.126	0.192
FIRESTONE TIRE & RUBBER CO	0.734	0.206	0.247	0.213	0.149	0.130	0.194	0.202	0.178	0.143	[illegible]	0.182
UNITED BANKS OF COLORADO	0.572	0.012	0.014	0.013	0.011	0.010	0.011	0.006	0.007	0.006	0.008	0.010
GOODRICH (B.F.) CO	0.793	0.090	0.139	0.109	0.036	0.095	0.136	0.141	0.110	0.045	0.034	0.093
INTERCO INC	0.953	0.227	0.290	0.279	0.282	0.260	0.269	0.271	0.276	0.255	0.283	0.273
BROWN GROUP INC	0.735	0.308	0.324	0.237	0.237	0.249	0.245	0.249	0.175	0.134	0.240	0.240
U S SHOE CORP	0.942	0.251	0.324	0.272	0.219	0.214	0.236	0.212	0.203	0.208	0.370	0.251
GENESCO INC	1.373	0.219	0.294	0.270	0.206	0.200	0.093	0.138	0.190	-0.054	0.229	0.174
CELANESE CORP	0.561	0.154	0.192	0.212	0.120	0.151	0.118	0.170	0.203	0.085	0.141	0.155
U S GYPSUM CO	0.830	0.141	0.160	0.134	0.076	0.157	0.198	0.192	0.104	0.055	0.131	0.139
NATIONAL GYPSUM CO	0.839	0.098	0.118	0.120	0.071	0.117	0.169	0.164	0.135	0.094	0.133	0.122
CPC INTL INC	0.517	0.217	0.241	0.236	0.225	0.176	0.213	0.230	0.251	0.282	0.276	0.235
STOKELY-VAN CAMP INC	0.634	0.165	0.110	0.100	0.128	0.126	0.154	0.164	0.173	0.131	0.096	0.135
ESMARK INC	0.473	0.101	0.061	0.101	0.137	0.137	0.128	0.169	0.219	0.222	0.152	0.142
GENERAL MILLS INC	0.603	0.483	0.422	0.382	0.354	0.355	0.386	0.344	0.270	0.323	0.323	0.364
PILLSBURY CO	0.717	0.198	0.212	0.268	0.152	0.190	0.218	0.234	0.250	0.312	0.278	0.231
AMERICAN CAN CO	0.313	0.202	0.197	0.157	0.162	0.115	0.123	0.154	0.205	0.145	0.181	0.164
CONTINENTAL GROUP	0.317	0.219	0.236	0.241	0.209	0.151	0.156	[illegible]	0.215	0.161	0.130	0.155
ANHEUSER-BUSCH INC	0.534	0.263	0.313	0.280	0.322	0.316	0.300	0.232	0.203	0.250	0.142	0.262
PABST BREWING CO	0.562	0.277	0.296	0.236	0.228	0.254	0.249	0.185	0.125	0.147	0.216	0.221
COORS (ADOLPH) CO	0.000	-0.000	-0.000	-0.000	-0.000	-0.000	-0.000	-0.000	-0.000	0.534	0.297	0.083
SCHLITZ (JOSEPH) BREWING	0.841	0.219	0.266	0.282	0.257	0.299	0.342	0.370	0.281	0.168	0.243	0.277
AMERICAN BAKERIES CO	0.871	0.158	0.096	-0.072	0.098	-0.021	-0.000	-0.131	-0.098	0.214	0.204	0.045
BURLINGTON INDUSTRIES INC	0.889	0.191	0.274	0.245	0.203	0.110	0.120	0.195	0.207	0.082	0.197	0.182
STEVENS (J.P.) & CO	0.740	0.109	0.176	0.142	0.027	-0.002	0.072	0.157	0.137	0.088	0.168	0.112
CONE MILLS CORP	0.744	0.080	0.038	0.042	0.070	0.100	0.106	0.113	0.190	0.245	0.306	0.129
DAN RIVER INC	0.912	0.096	0.088	-0.008	-0.028	-0.041	0.046	0.132	0.067	-0.063	0.148	0.044

TABLE NO. 24

RATE OF RETURN MEASURE 4

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
~~COMBO INDS~~	~~0.678~~	~~[illegible]~~	~~0.167~~	~~0.205~~	~~0.152~~	~~0.152~~	~~0.152~~	~~[illegible]~~	~~[illegible]~~	~~[illegible]~~	~~[illegible]~~	~~[illegible]~~
OWENS-ILLINOIS INC	0.613	0.131	0.170	0.218	0.201	0.159	0.153	0.164	0.176	0.162	0.172	0.171
ANCHOR HOCKING CORP	0.736	0.210	0.314	0.365	0.280	0.249	0.242	0.197	0.157	0.193	0.230	0.244
GOODYEAR TIRE & RUBBER CO	0.703	0.204	0.247	0.247	0.192	0.242	0.240	0.212	0.174	0.174	0.136	0.207
FIRESTONE TIRE & RUBBER CO	0.734	0.206	0.247	0.213	0.149	0.130	0.194	0.202	0.178	0.143	0.112	0.182
UNITED BANKS OF COLORADO	0.572	0.012	0.014	0.013	0.011	0.010	0.011	0.006	0.007	0.006	0.008	0.010
GOODRICH (B.F.) CO	0.793	0.090	0.139	0.114	0.039	0.101	0.139	0.141	0.110	0.045	0.034	0.095
INTERCO INC	0.953	0.227	0.290	0.279	0.282	0.260	0.269	0.271	0.277	0.258	0.285	0.274
BROWN GROUP INC	0.735	0.308	0.324	0.237	0.237	0.249	0.245	0.249	0.175	0.134	0.240	0.240
U S SHOE CORP	0.942	0.251	0.324	0.272	0.220	0.216	0.238	0.214	0.206	0.210	0.371	0.252
GENESCO INC	1.373	0.219	0.294	0.272	0.210	0.206	0.095	0.141	0.193	-0.055	0.230	0.177
CELANESE CORP	0.561	0.154	0.192	0.229	0.135	0.172	0.136	0.192	0.236	0.101	0.167	0.171
U S GYPSUM CO	0.830	0.141	0.160	0.139	0.083	0.164	0.208	0.197	0.104	0.095	0.131	0.142
NATIONAL GYPSUM CO	0.839	0.098	0.118	0.120	0.071	0.119	0.171	0.166	0.135	0.094	0.133	0.122
CPC INTL INC	0.517	0.217	0.241	0.243	0.240	0.190	0.226	0.246	0.274	0.318	0.311	0.251
STOKELY-VAN CAMP INC	0.634	0.165	0.110	0.102	0.131	0.127	0.157	0.168	0.177	0.133	0.098	0.137
ESMARK INC	0.473	0.101	0.061	0.101	0.137	0.137	0.128	0.169	0.226	0.241	0.164	0.147
GENERAL MILLS INC	0.603	0.483	0.422	0.382	0.354	0.355	0.386	0.344	0.283	0.346	0.347	0.370
PILLSBURY CO	0.717	0.198	0.212	0.268	0.152	0.190	0.218	0.234	0.250	0.312	0.278	0.231
AMERICAN CAN CO	0.313	0.202	0.197	0.161	0.170	0.119	0.126	0.161	0.215	0.152	0.190	0.169
CONTINENTAL GROUP	0.317	0.219	0.236	0.252	0.230	0.169	0.184	0.211	0.235	0.176	0.196	0.211
ANHEUSER-BUSCH INC	0.534	0.263	0.313	0.305	0.374	0.354	0.338	0.267	0.234	0.297	0.162	0.291
PABST BREWING CO	0.562	0.277	0.296	0.260	0.250	0.255	0.255	0.192	0.130	0.152	0.225	0.229
COORS (ADOLPH) CO	0.000	-0.000	-0.000	-0.000	-0.000	-0.000	-0.000	-0.000	-0.000	0.640	0.341	0.098
SCHLITZ (JOSEPH) BREWING	0.841	0.219	0.266	0.296	0.357	0.342	0.351	0.390	0.345	0.248	0.303	0.312
AMERICAN BAKERIES CO	0.871	0.158	0.096	-0.073	0.100	-0.021	-0.000	-0.136	-0.103	0.224	0.213	0.046
BURLINGTON INDUSTRIES INC	0.889	0.191	0.274	0.249	0.212	0.114	0.124	0.200	0.213	0.084	0.201	0.186
STEVENS (J.P.) & CO	0.740	0.109	0.176	0.144	0.027	-0.002	0.073	0.160	0.151	0.089	0.172	0.114
CONE MILLS CORP	0.744	0.080	0.038	0.042	0.070	0.100	0.106	0.113	0.190	0.245	0.306	0.129
DAN RIVER INC	0.912	0.096	0.088	-0.008	-0.029	-0.042	0.046	0.135	0.070	-0.065	0.151	0.044

APPENDIX 3

Ten-Year Returns for Medium Barrier-To-Entry Group

TABLE NO. 31

RATE OF RETURN MEASURE 1

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
ALUMINUM CO OF AMERICA	0.516	0.112	0.102	0.107	0.091	0.052	0.077	0.078	0.117	0.043	0.069	0.087
REYNOLDS METALS CO	1.017	0.071	0.049	0.071	0.064	0.030	0.025	0.059	0.120	0.061	0.069	0.062
KAISER ALUMINUM & CHEM CORP	1.182	0.094	0.087	0.094	0.070	0.049	0.040	0.071	0.122	0.089	0.070	0.079
NABISCO INC	0.760	0.211	0.212	0.153	0.193	0.202	0.181	0.135	0.126	0.158	0.184	0.176
UNITED BRANDS	1.319	0.138	0.131	0.116	0.041	0.031	0.046	0.064	-0.015	0.055	0.053	0.066
EXXON CORP	0.276	0.150	0.155	0.144	0.148	0.168	0.198	0.278	0.402	0.319	0.241	0.220
TEXACO INC	0.553	0.145	0.143	0.126	0.136	0.145	0.135	0.169	0.195	0.116	0.116	0.143
MOBIL CORP	0.478	0.113	0.116	0.120	0.125	0.151	0.165	0.215	0.317	0.233	0.243	0.180
STANDARD OIL CO (INDIANA)	0.104	0.100	0.102	0.099	0.097	0.094	0.096	0.130	0.219	0.224	0.222	0.134
U S STEEL CORP	0.646	0.053	0.070	0.055	0.036	0.036	0.044	0.089	0.155	0.114	0.073	0.073
BETHLEHEM STEEL CORP	0.800	0.077	0.081	0.067	0.051	0.076	0.068	0.105	0.157	0.076	0.057	0.081
JORGENSEN (EARLE M.) CO	0.589	0.150	0.150	0.154	0.104	0.114	0.145	0.196	0.286	0.254	0.207	0.176
PROCTER & GAMBLE CO	0.377	0.235	0.233	0.233	0.251	0.237	0.243	0.229	0.213	0.196	0.204	0.227
COLGATE-PALMOLIVE CO	0.552	0.159	0.165	0.159	0.152	0.163	0.183	0.173	0.172	0.173	0.189	0.169
INTL HARVESTER CO	0.538	0.102	0.080	0.070	0.066	0.056	0.077	0.081	0.098	0.095	0.110	0.084
ALLIS-CHALMERS CORP	0.893	0.041	-0.092	0.107	0.099	0.066	0.064	0.054	0.061	0.069	0.117	0.059
DEERE & CO	0.413	0.128	0.095	0.103	0.094	0.095	0.144	0.191	0.165	0.157	0.174	0.135
KENNECOTT COPPER CORP	0.325	0.111	0.124	0.160	0.170	0.072	0.070	0.126	0.124	0.007	0.015	0.098
PHELPS DODGE CORP	0.472	0.131	0.157	0.187	0.210	0.130	0.138	0.166	0.126	0.045	0.054	0.134
IDEAL BASIC INDUSTRIES INC	0.882	0.098	0.075	0.072	0.086	0.128	0.148	0.154	0.167	0.155	0.143	0.123
LONE STAR INDUSTRIES	0.678	0.076	0.087	0.084	0.086	0.104	0.109	0.119	0.100	0.077	0.085	0.093
GENERAL PORTLAND INC	0.940	0.073	0.114	0.113	0.131	0.118	0.113	0.104	0.048	0.016	0.016	0.085
U S SHOE CORP	0.942	0.160	0.191	0.162	0.134	0.129	0.138	0.127	0.128	0.132	0.212	0.151
COMPO INDS	0.678	0.082	0.111	0.140	0.110	0.104	0.109	0.116	-0.031	-0.007	0.065	0.080

TABLE NO. 32

RATE OF RETURN MEASURE 2

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
ALUMINUM CO OF AMERICA	0.516	0.112	0.102	0.110	0.098	0.056	0.080	0.080	0.124	0.046	0.053	0.090
REYNOLDS METALS CO	1.017	0.071	0.049	0.074	0.068	0.031	0.026	0.063	0.127	0.064	0.071	0.064
KAISER ALUMINUM & CHEM CORP	1.182	0.094	0.087	0.096	0.072	0.049	0.041	0.072	0.124	0.091	0.072	0.080
NABISCO INC	0.760	0.211	0.212	0.153	0.193	0.202	0.181	0.135	0.126	0.158	0.184	0.176
UNITED BRANDS	1.319	0.138	0.131	0.116	0.041	0.031	0.046	0.064	-0.015	0.055	0.053	0.066
EXXON CORP	0.276	0.150	0.155	0.144	0.148	0.168	0.198	0.278	0.402	0.319	0.241	0.220
TEXACO INC	0.553	0.145	0.143	0.126	0.136	0.145	0.135	0.169	0.195	0.116	0.116	0.143
MOBIL CORP	0.478	0.113	0.116	0.120	0.125	0.151	0.165	0.215	0.317	0.233	0.243	0.180
STANDARD OIL CO (INDIANA)	0.104	0.100	0.102	0.099	0.097	0.094	0.096	0.130	0.229	0.224	0.222	0.139
U S STEEL CORP	0.646	0.053	0.070	0.055	0.036	0.036	0.044	0.089	0.155	0.114	0.073	0.073
BETHLEHEM STEEL CORP	0.800	0.077	0.081	0.067	0.051	0.076	0.068	0.105	0.157	0.076	0.057	0.081
JORGENSEN (EARLE M.) CO	0.589	0.150	0.150	0.155	0.106	0.116	0.147	0.199	0.288	0.257	0.210	0.178
PROCTER & GAMBLE CO	0.377	0.235	0.233	0.233	0.251	0.237	0.243	0.229	0.213	0.196	0.204	0.227
COLGATE-PALMOLIVE CO	0.552	0.159	0.165	0.159	0.152	0.163	0.183	0.173	0.172	0.173	0.189	0.169
INTL HARVESTER CO	0.538	0.102	0.080	0.070	0.066	0.056	0.077	0.081	0.098	0.095	0.110	0.084
ALLIS-CHALMERS CORP	0.893	0.041	-0.092	0.107	0.099	0.066	0.064	0.054	0.061	0.069	0.117	0.059
DEERE & CO	0.413	0.128	0.095	0.103	0.094	0.095	0.144	0.191	0.165	0.157	0.174	0.135
KENNECOTT COPPER CORP	0.325	0.111	0.124	0.160	0.170	0.072	0.070	0.126	0.124	0.007	0.015	0.098
PHELPS DODGE CORP	0.472	0.131	0.157	0.187	0.210	0.130	0.138	0.166	0.126	0.045	0.054	0.134
IDEAL BASIC INDUSTRIES INC	0.882	0.098	0.075	0.072	0.087	0.130	0.156	0.167	0.178	0.166	0.152	0.128
LONE STAR INDUSTRIES	0.678	0.076	0.087	0.084	0.086	0.104	0.108	0.119	0.100	0.077	0.087	0.093
GENERAL PORTLAND INC	0.940	0.073	0.114	0.113	0.131	0.118	0.118	0.104	0.048	0.018	0.016	0.085
U S SHOE CORP	0.942	0.160	0.191	0.162	0.134	0.129	0.139	0.128	0.128	0.133	0.212	0.152
COMPO INDS	0.678	0.082	0.111	0.140	0.110	0.104	0.109	0.116	-0.031	-0.007	0.065	0.080

TABLE NO. 3.3

RATE OF RETURN MEASURE 3

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
UMINUM CO OF AMERICA	0.516	0.173	0.155	0.164	0.131	0.055	0.098	0.101	0.176	0.033	0.121	0.121
EYNOLDS METALS CO	1.017	0.113	0.056	0.106	0.086	0.002	-0.011	0.075	0.208	0.077	0.093	0.081
AISER ALUMINUM & CHEM CORP	1.182	0.173	0.150	0.161	0.106	0.052	0.026	0.092	0.221	0.144	0.098	0.122
ABISCO INC	0.760	0.310	0.322	0.236	0.297	0.322	0.295	0.219	0.211	0.288	0.325	0.283
NITED BRANDS	1.319	0.164	0.155	0.140	0.019	0.008	0.044	0.065	-0.116	0.050	0.051	0.053
XXON CORP	0.276	0.204	0.215	0.201	0.209	0.241	0.286	0.416	0.644	0.517	0.379	0.331
EXACO INC	0.553	0.191	0.184	0.159	0.171	0.185	0.175	0.225	0.288	0.173	0.175	0.193
OBIL CORP	0.478	0.157	0.162	0.170	0.181	0.230	0.256	0.347	0.567	0.421	0.450	0.294
TANDARD OIL CO (INDIANA)	0.104	0.125	0.129	0.125	0.123	0.120	0.125	0.182	0.347	0.345	0.347	0.197
S STEEL CORP	0.646	0.074	0.100	0.076	0.043	0.040	0.052	0.127	0.238	0.160	0.097	0.101
ETHLEHEM STEEL CORP	0.800	0.102	0.113	0.092	0.063	0.101	0.086	0.144	0.229	0.097	0.063	0.109
ORGENSEN (EARLE M.) CO	0.589	0.248	0.232	0.236	0.141	0.156	0.211	0.291	0.457	0.376	0.283	0.263
ROCTER & GAMBLE CO	0.377	0.320	0.315	0.313	0.337	0.316	0.329	0.314	0.294	0.279	0.297	0.311
OLGATE-PALMOLIVE CO	0.552	0.248	0.256	0.247	0.231	0.249	0.280	0.266	0.269	0.269	0.289	0.260
NTL HARVESTER CO	0.538	0.144	0.108	0.088	0.076	0.059	0.109	0.113	0.136	0.123	0.175	0.113
LLIS-CHALMERS CORP	0.893	0.014	-0.274	0.119	0.092	0.042	0.048	0.064	0.087	0.114	0.228	0.053
EERE & CO	0.413	0.195	0.136	0.147	0.121	0.142	0.239	0.320	0.266	0.241	0.304	0.211
ENNECOTT COPPER CORP	0.325	0.120	0.141	0.202	0.213	0.077	0.077	0.151	0.142	-0.016	-0.010	0.110
HELPS DODGE CORP	0.472	0.151	0.177	0.226	0.265	0.160	0.167	0.217	0.168	0.035	0.050	0.162
DEAL BASIC INDUSTRIES INC	0.882	0.126	0.093	0.085	0.109	0.171	0.193	0.195	0.211	0.197	0.182	0.156
ONE STAR INDUSTRIES	0.673	0.102	0.126	0.118	0.117	0.138	0.149	0.175	0.136	0.093	0.098	0.125
ENERAL PORTLAND INC	0.940	0.089	0.140	0.133	0.155	0.156	0.151	0.146	0.050	-0.006	-0.004	0.101
S SHOE CORP	0.942	0.251	0.324	0.272	0.219	0.214	0.236	0.212	0.203	0.208	0.370	0.251
OMPO INDS	0.678	0.109	0.167	0.205	0.152	0.152	0.182	0.185	-0.172	-0.091	0.090	0.098

TABLE NO. 3.4

RATE OF RETURN MEASURE 4

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
LUMINUM CO OF AMERICA	0.516	0.173	0.155	0.174	0.151	0.064	0.106	0.106	0.196	0.037	0.134	0.130
EYNOLDS METALS CO	1.017	0.113	0.056	0.118	0.101	0.003	-0.013	0.089	0.238	0.084	0.100	0.089
AISER ALUMINUM & CHEM CORP	1.182	0.173	0.150	0.170	0.112	0.052	0.027	0.096	0.233	0.153	0.105	0.127
ABISCO INC	0.760	0.310	0.322	0.236	0.297	0.322	0.295	0.219	0.211	0.288	0.325	0.283
NITED BRANDS	1.313	0.164	0.155	0.140	0.019	0.008	0.044	0.065	-0.118	0.050	0.051	0.058
XXON CORP	0.276	0.204	0.215	0.201	0.209	0.241	0.286	0.416	0.644	0.517	0.379	0.331
EXACO INC	0.553	0.191	0.184	0.159	0.171	0.135	0.175	0.225	0.288	0.173	0.175	0.193
OBIL CORP	0.478	0.157	0.162	0.170	0.181	0.230	0.256	0.347	0.567	0.421	0.450	0.294
TANDARD OIL CO (INDIANA)	0.104	0.125	0.129	0.125	0.123	0.120	0.125	0.182	0.347	0.345	0.347	0.197
S STEEL CORP	0.646	0.074	0.100	0.076	0.043	0.040	0.052	0.127	0.238	0.168	0.097	0.101
ETHLEHEM STEEL CORP	0.800	0.102	0.113	0.092	0.063	0.101	0.086	0.144	0.229	0.097	0.063	0.109
ORGENSEN (EARLE M.) CO	0.589	0.248	0.232	0.238	0.144	0.160	0.216	0.297	0.461	0.383	0.289	0.267
ROCTER & GAMBLE CO	0.377	0.320	0.315	0.313	0.337	0.316	0.329	0.314	0.294	0.279	0.297	0.311
OLGATE-PALMOLIVE CO	0.552	0.248	0.256	0.247	0.231	0.249	0.280	0.266	0.269	0.269	0.288	0.260
NTL HARVESTER CO	0.538	0.144	0.108	0.088	0.076	0.059	0.109	0.113	0.136	0.123	0.175	0.113
LLIS-CHALMERS CORP	0.893	0.014	-0.274	0.119	0.092	0.042	0.048	0.064	0.087	0.114	0.228	0.053
EERE & CO	0.413	0.195	0.136	0.147	0.121	0.142	0.239	0.320	0.266	0.241	0.304	0.211
ENNECOTT COPPER CORP	0.325	0.120	0.141	0.202	0.213	0.077	0.077	0.151	0.142	-0.016	-0.010	0.110
HELPS DODGE CORP	0.472	0.151	0.177	0.226	0.265	0.160	0.167	0.217	0.168	0.035	0.050	0.162
DEAL BASIC INDUSTRIES INC	0.882	0.126	0.093	0.085	0.110	0.175	0.207	0.218	0.230	0.217	0.200	0.166
ONE STAR INDUSTRIES	0.673	0.102	0.126	0.118	0.117	0.138	0.149	0.175	0.136	0.094	0.103	0.126
ENERAL PORTLAND INC	0.940	0.089	0.140	0.133	0.155	0.156	0.151	0.146	0.050	-0.006	-0.004	0.101
S SHOE CORP	0.942	0.251	0.324	0.272	0.220	0.216	0.238	0.214	0.206	0.210	0.371	0.252
OMPO INDS	0.678	0.109	0.167	0.205	0.152	0.152	0.182	0.185	-0.172	-0.091	0.090	0.098

APPENDIX 4

Ten-Year Returns for High Barrier-To-Entry Group

Final

TABLE NO. 41

RATE OF RETURN MEASURE 1

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
GENERAL MOTORS CORP	0.619	0.233	0.261	0.240	0.057	0.233	0.235	0.239	0.090	0.127	0.250	0.197
FORD MOTOR CO	0.576	0.023	0.158	0.128	0.114	0.137	0.160	0.145	0.062	0.043	0.130	0.111
CHRYSLER CORP	1.316	0.109	0.155	0.044	0.004	0.043	0.098	[illegible]	0.006	0.004	0.108	0.064
WRIGLEY (WILLIAM) JR CO	0.475	0.249	0.266	0.258	0.219	0.228	0.217	0.224	0.188	0.279	0.275	0.240
REYNOLDS (R.J.) INDS	0.463	0.257	0.274	0.268	0.251	0.268	0.234	[illegible]	0.251	0.272	0.201	0.253
AMERICAN BRANDS INC	0.516	0.176	0.170	0.170	0.154	0.150	0.152	0.153	0.153	0.157	0.144	0.158
LIGGETT GROUP	0.618	0.120	0.126	0.127	0.145	0.149	0.121	0.113	0.122	0.132	0.130	0.129
PHILIP MORRIS INC	0.273	0.158	0.162	0.164	0.167	0.171	0.173	0.166	0.164	0.162	0.173	0.166
MERCK & CO	0.264	0.392	0.388	0.393	0.371	0.364	0.353	[illegible]	[illegible]	0.262	0.262	0.349
PFIZER INC	0.211	0.177	0.187	0.192	0.186	0.175	0.169	0.163	0.155	0.143	0.140	0.169
SCHERING-PLOUGH	0.274	0.275	0.306	0.328	0.385	0.316	0.336	0.347	0.324	0.299	0.271	0.320
ABBOTT LABORATORIES	0.590	0.201	0.208	0.201	0.196	0.095	0.136	0.137	0.141	0.152	0.166	0.163
SEAGRAM CO LTD	0.565	0.103	0.106	0.105	[illegible]	0.103	0.099	0.099	0.104	0.097	0.091	0.101
NATIONAL DISTILLERS &CHEMICL	0.654	0.114	0.099	0.107	0.089	0.083	0.085	0.105	0.181	0.141	0.162	0.117
WALKER(HIRAM) GOODRHM & WORT	0.341	0.226	0.225	0.221	0.202	0.182	0.171	0.189	0.181	0.136	0.142	0.187
TEXASGULF INC	0.695	0.224	0.230	0.165	0.124	0.073	0.094	0.179	0.324	0.174	0.099	0.168
FREEPORT MINERALS CO	0.465	0.141	0.185	0.103	0.073	0.064	0.083	0.132	0.265	0.101	0.150	0.130
PPG INDUSTRIES INC	0.701	0.093	0.103	0.106	0.065	0.096	0.110	0.119	0.105	0.106	0.160	0.107
LIBBEY-OWENS-FORD CO	0.816	0.192	0.251	0.195	0.095	0.205	0.233	0.245	0.114	0.107	0.190	0.183

TABLE NO. 42

RATE OF RETURN MEASURE 2

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
GENERAL MOTORS CORP	0.619	0.233	0.261	0.244	0.055	0.239	0.240	0.244	0.093	0.131	0.255	0.200
FORD MOTOR CO	0.576	0.023	0.158	0.129	0.116	0.139	0.164	0.150	0.064	0.049	0.132	0.113
CHRYSLER CORP	1.316	0.109	0.155	0.045	0.004	0.045	0.091	0.086	0.006	0.004	0.111	0.066
WRIGLEY (WILLIAM) JR CO	0.475	0.249	0.266	0.262	0.225	0.233	0.219	0.224	0.188	0.279	0.278	0.242
REYNOLDS (R.J.) INDS	0.463	0.257	0.274	0.273	0.262	0.287	0.243	0.218	0.291	0.272	0.201	0.258
AMERICAN BRANDS INC	0.516	0.176	0.170	0.170	0.155	0.150	0.153	0.154	0.154	0.156	0.145	0.158
LIGGETT GROUP	0.618	0.120	0.126	0.127	0.145	0.149	0.121	0.118	0.123	0.132	0.130	0.129
PHILIP MORRIS INC	0.273	0.158	0.162	0.164	0.170	0.176	0.183	0.178	0.175	0.170	0.180	0.172
MERCK & CO	0.264	0.392	0.388	0.394	0.382	0.372	0.353	0.352	0.333	0.310	0.300	0.358
PFIZER INC	0.211	0.177	0.187	0.194	0.193	0.183	0.175	0.169	0.161	0.151	0.146	0.174
SCHERING-PLOUGH	0.274	0.275	0.306	0.335	0.404	0.332	0.348	0.361	0.344	0.320	0.297	0.332
ABBOTT LABORATORIES	0.590	0.201	0.208	0.201	0.196	0.095	0.136	0.137	0.144	0.157	0.173	0.165
SEAGRAM CO LTD	0.565	0.103	0.106	0.105	0.107	0.103	0.099	0.099	0.105	0.099	0.092	0.102
NATIONAL DISTILLERS &CHEMICL	0.654	0.114	0.099	0.109	0.092	0.086	0.087	0.107	0.183	0.145	0.166	0.119
WALKER(HIRAM) GOODRHM & WORT	0.341	0.226	0.225	0.221	0.208	0.187	0.171	0.190	0.181	0.136	0.142	0.189
TEXASGULF INC	0.695	0.224	0.230	0.165	0.124	0.073	0.094	0.179	0.324	0.174	0.098	0.168
FREEPORT MINERALS CO	0.465	0.141	0.189	0.103	0.073	0.064	0.083	0.132	0.265	0.101	0.150	0.130
PPG INDUSTRIES INC	0.701	0.093	0.103	0.110	0.071	0.103	0.113	0.123	0.114	0.111	0.172	0.112
LIBBEY-OWENS-FORD CO	0.816	0.192	0.251	0.203	0.099	0.209	0.244	0.256	0.118	0.109	0.192	0.187

TABLE NO. 4.3

RATE OF RETURN MEASURE 3

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
GENERAL MOTORS CORP	0.619	0.315	0.349	0.324	0.072	0.341	0.357	0.353	0.126	0.175	0.373	0.275
FORD MOTOR CO	0.576	0.023	0.241	0.192	0.166	0.207	0.253	0.226	0.074	0.050	0.217	0.165
CHRYSLER CORP	1.316	0.190	0.280	0.074	-0.010	0.058	0.155	0.155	-0.047	-0.063	0.183	0.097
WRIGLEY (WILLIAM) JR CO	0.475	0.290	0.310	0.308	0.266	0.289	0.279	0.280	0.236	0.363	0.361	0.298
REYNOLDS (R.J.) INDS	0.463	0.365	0.367	0.353	0.365	0.395	0.342	0.311	0.436	0.407	0.290	0.363
AMERICAN BRANDS INC	0.516	0.248	0.275	0.294	0.280	0.275	0.270	0.272	0.266	0.276	0.243	0.270
LIGGETT GROUP	0.618	0.166	0.177	0.193	0.227	0.236	0.186	0.169	0.177	0.194	0.169	0.191
PHILIP MORRIS INC	0.273	0.312	0.337	0.341	0.361	0.350	0.337	0.316	0.309	0.305	0.332	0.330
MERCK & CO	0.264	0.524	0.504	0.509	0.490	0.488	0.470	0.471	0.454	[illegible]	[illegible]	0.472
PFIZER INC	0.211	0.246	0.263	0.268	0.268	0.261	0.260	0.253	0.241	0.223	0.221	0.250
SCHERING-PLOUGH	0.274	0.376	0.429	0.468	0.542	0.445	0.461	0.460	0.418	0.377	0.352	0.433
ABBOTT LABORATORIES	0.590	0.264	0.291	0.297	0.295	0.127	0.209	0.211	0.215	0.249	0.263	0.242
SEAGRAM CO LTD	0.565	0.138	0.146	0.147	0.142	0.139	0.135	0.134	0.133	0.113	0.114	0.134
NATIONAL DISTILLERS &CHEMICL	0.654	0.184	0.155	0.170	0.137	0.126	0.123	0.163	0.255	0.209	0.243	0.191
WALKER(HIRAM) GOODRHM & WORT	0.341	0.278	0.285	0.290	0.262	0.242	0.226	0.241	0.232	0.165	0.175	0.240
TEXASGULF INC	0.695	0.333	0.322	0.221	0.161	0.090	0.115	0.235	0.430	0.225	0.115	0.223
FREEPORT MINERALS CO	0.465	0.164	0.219	0.117	0.080	0.065	0.090	0.144	0.297	0.115	0.170	0.147
PPG INDUSTRIES INC	0.701	0.122	0.138	0.142	0.076	0.123	0.146	0.160	0.145	0.142	0.232	0.143
LIBBEY-OWENS-FORD CO	0.816	0.218	0.350	0.370	0.152	0.425	0.452	0.449	0.179	0.165	0.335	0.310

TABLE NO. 4.4

RATE OF RETURN MEASURE 4

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
GENERAL MOTORS CORP	0.619	0.315	0.349	0.332	0.075	0.354	0.367	0.364	0.142	0.184	0.392	0.286
FORD MOTOR CO	0.576	0.023	0.241	0.195	0.171	0.214	0.263	0.239	0.078	0.052	0.225	0.170
CHRYSLER CORP	1.316	0.190	0.280	0.077	-0.011	0.061	0.163	0.167	-0.051	-0.069	0.196	0.100
WRIGLEY (WILLIAM) JR CO	0.475	0.290	0.310	0.313	0.275	0.297	0.284	0.281	0.236	0.363	0.366	0.302
REYNOLDS (R.J.) INDS	0.463	0.369	0.367	0.364	0.391	0.434	0.363	0.311	0.436	0.407	0.290	0.373
AMERICAN BRANDS INC	0.516	0.248	0.275	0.295	0.282	0.278	0.273	0.276	0.270	0.279	0.245	0.272
LIGGETT GROUP	0.619	0.166	0.177	0.193	0.227	0.236	0.186	0.169	0.177	0.194	0.189	0.191
PHILIP MORRIS INC	0.273	0.312	0.337	0.345	0.374	0.378	0.385	0.378	0.368	0.247	0.366	0.359
MERCK & CO	0.264	0.524	0.504	0.512	0.510	0.503	0.470	0.471	0.464	0.474	0.488	0.492
PFIZER INC	0.211	0.246	0.263	0.274	0.283	0.283	0.277	0.261	0.257	0.251	0.241	0.264
SCHERING-PLOUGH	0.274	0.376	0.429	0.483	0.582	0.479	0.484	0.485	0.452	0.410	0.380	0.456
ABBOTT LABORATORIES	0.590	0.264	0.291	0.297	0.295	0.127	0.209	0.211	0.227	0.269	0.285	0.247
SEAGRAM CO LTD	0.565	0.138	0.146	0.147	0.142	0.138	0.135	0.135	0.135	0.116	0.117	0.135
NATIONAL DISTILLERS &CHEMICL	0.654	0.164	0.155	0.175	0.146	0.134	0.135	0.167	0.303	0.218	0.253	0.187
WALKER(HIRAM) GOODRHM & WORT	0.341	0.278	0.285	0.290	0.273	0.251	0.226	0.242	0.233	0.166	0.175	0.242
TEXASGULF INC	0.695	0.333	0.322	0.221	0.161	0.090	0.115	0.235	0.430	0.225	0.115	0.225
FREEPORT MINERALS CO	0.465	0.164	0.219	0.117	0.080	0.065	0.093	0.144	0.297	0.115	0.170	0.147
PPG INDUSTRIES INC	0.701	0.122	0.138	0.151	0.091	0.141	0.154	0.169	0.157	0.154	0.263	0.154
LIBBEY-OWENS-FORD CO	0.816	0.218	0.350	0.403	0.170	0.450	0.500	0.494	0.190	0.170	0.342	0.329

APPENDIX 5

Ten-Year Returns for Electric Utilities On A State-By-State Basis

TABLE NO. 5.1

RATE OF RETURN MEASURE 1

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
STATES REGULATING THE UTILITIES BELOW ARE ARIZONA												
ARIZONA PUBLIC SERVICE CO	0.491	0.061	0.067	0.073	0.076	0.069	0.074	0.081	0.076	0.089	0.086	0.075
TUCSON GAS & ELECTRIC	0.532	0.096	0.096	0.099	0.100	0.084	0.083	0.078	0.071	0.093	0.100	0.090
STATES REGULATING THE UTILITIES BELOW ARE CALIFORNIA												
PACIFIC GAS & ELECTRIC	0.240	0.084	0.084	0.083	0.077	0.086	0.084	0.083	0.080	0.070	0.073	0.080
SAN DIEGO GAS & ELECTRIC	0.511	0.087	0.088	0.092	0.084	0.078	0.069	0.069	0.081	0.059	0.084	0.079
SOUTHERN CALIF EDISON CO	0.382	0.079	0.073	0.072	0.075	0.071	0.073	0.073	0.105	0.079	0.083	0.078
STATES REGULATING THE UTILITIES BELOW ARE Colorado												
PUBLIC SERVICE CO OF COLO	0.365	0.082	0.085	0.084	0.082	0.075	0.076	0.076	0.068	0.087	0.082	0.080
STATES REGULATING THE UTILITIES BELOW ARE Connecticut												
UNITED ILLUMINATING CO	0.412	0.096	0.089	0.094	0.085	0.063	0.095	0.068	0.083	0.076	0.074	0.082
STATES REGULATING THE UTILITIES BELOW ARE Delaware												
DELMARVA POWER & LIGHT	0.472	0.100	0.103	0.097	0.079	0.080	0.082	0.082	0.083	0.074	0.070	0.085
STATES REGULATING THE UTILITIES BELOW ARE Florida												
FLORIDA POWER & LIGHT	0.575	0.110	0.116	0.114	0.103	0.108	0.099	0.105	0.091	0.116	0.094	0.106
FLORIDA POWER CORP	0.636	0.103	0.108	0.110	0.102	0.099	0.100	0.090	0.079	0.103	0.100	0.099
TAMPA ELECTRIC CO	0.773	0.106	0.101	0.104	0.098	0.075	0.098	0.096	0.079	0.104	0.105	0.097
STATES REGULATING THE UTILITIES BELOW ARE Georgia												
SAVANNAH ELEC & POWER	0.537	0.085	0.093	0.091	0.086	0.075	0.070	0.073	0.085	0.098	0.098	0.085
STATES REGULATING THE UTILITIES BELOW ARE HAWAII												
HAWAIIAN ELECTRIC CO	0.477	0.082	0.091	0.092	0.088	0.086	0.086	0.089	0.091	0.100	0.100	0.090
STATES REGULATING THE UTILITIES BELOW ARE ILLINOIS												
ILLINOIS POWER CO	0.497	0.128	0.126	0.125	0.118	0.100	0.095	0.096	0.089	0.104	0.099	0.108
COMMONWEALTH EDISON	0.307	0.114	0.113	0.102	0.091	0.084	0.090	0.092	0.085	0.092	0.094	0.096
CENTRAL ILL PUBLIC SERVICE	0.567	0.113	0.115	0.114	0.107	0.105	0.092	0.087	0.085	0.094	0.091	0.101
CENTRAL ILLINOIS LIGHT	0.437	0.100	0.099	0.101	0.105	0.102	0.099	0.087	0.079	0.078	0.094	0.094
STATES REGULATING THE UTILITIES BELOW ARE INDIANA												
PUBLIC SERVICE CO OF IND	0.423	0.115	0.119	0.116	0.109	0.093	0.108	0.116	0.110	0.106	0.131	0.112
NORTHERN INDIANA PUBLIC SERV	0.337	0.117	0.116	0.114	0.120	0.104	0.104	0.098	0.085	0.098	0.107	0.106
INDIANAPOLIS POWER & LIGHT	0.694	0.116	0.114	0.109	0.103	0.104	0.118	0.103	0.086	0.097	0.105	0.105
STATES REGULATING THE UTILITIES BELOW ARE IOWA												
IOWA POWER & LIGHT	0.353	0.095	0.093	0.090	0.078	0.084	0.083	0.097	0.090	0.106	0.102	0.092
IOWA SOUTHERN UTILITIES CO	0.571	0.116	0.119	0.129	0.128	0.124	0.128	0.111	0.106	0.107	0.109	0.118
STATES REGULATING THE UTILITIES BELOW ARE KANSAS												
KANSAS POWER & LIGHT	0.281	0.103	0.111	0.118	0.119	0.118	0.113	0.113	0.095	0.099	0.095	0.108
KANSAS GAS & ELECTRIC	0.558	0.110	0.111	0.118	0.113	0.103	0.098	0.086	0.085	0.105	0.102	0.103
STATES REGULATING THE UTILITIES BELOW ARE KENTUCKY												
LOUISVILLE GAS & ELECTRIC	0.436	0.132	0.140	0.142	0.132	0.123	0.112	0.109	0.097	0.110	0.106	0.120
STATES REGULATING THE UTILITIES BELOW ARE MAINE												
CENTRAL MAINE POWER CO	0.310	0.098	0.096	0.091	0.094	0.084	0.096	0.090	0.077	0.084	0.093	0.090
MAINE PUBLIC SERVICE	0.491	0.079	0.078	0.086	0.091	0.079	0.083	0.097	0.106	0.094	0.110	0.090
STATES REGULATING THE UTILITIES BELOW ARE Massachusetts												
BOSTON EDISON CO	0.525	0.093	0.093	0.089	0.078	0.075	0.069	0.073	0.084	0.089	0.091	0.083
FITCHBURG GAS & ELEC LIGHT	0.387	0.079	0.087	0.084	0.084	0.083	0.086	0.077	0.074	0.086	0.095	0.083
STATES REGULATING THE UTILITIES BELOW ARE Michigan												
EDISON SAULT ELECTRIC	0.0	0.114	0.114	0.101	0.090	0.078	0.080	0.094	0.108	0.088	0.082	0.095
DETROIT EDISON CO	0.714	0.091	0.087	0.085	0.073	0.072	0.079	0.076	0.072	0.074	0.076	0.078
UPPER PENINSULA POWER	0.440	0.087	0.087	0.086	0.075	0.073	0.095	0.099	0.070	0.076	0.098	0.085
CONSUMERS POWER CO	0.711	0.105	0.099	0.093	0.089	0.077	0.076	0.073	0.058	0.080	0.095	0.084
STATES REGULATING THE UTILITIES BELOW ARE MINNESOTA												
MINNESOTA POWER & LIGHT	0.390	0.085	0.096	0.090	0.082	0.084	0.080	0.085	0.085	0.100	0.104	0.089
STATES REGULATING THE UTILITIES BELOW ARE Missouri												
MISSOURI PUBLIC SERVICE CO	0.631	0.092	0.084	0.088	0.091	0.079	0.085	0.081	0.094	0.099	0.110	0.090
ST JOSEPH LIGHT & POWER	0.599	0.083	0.094	0.089	0.095	0.106	0.105	0.094	0.089	0.092	0.097	0.094
STATES REGULATING THE UTILITIES BELOW ARE NEVADA												
NEVADA POWER CO	0.650	0.087	0.093	0.091	0.087	0.084	0.090	0.078	0.082	0.070	0.085	0.085
STATES REGULATING THE UTILITIES BELOW ARE New Hampshire												
CONCORD ELECTRIC CO	0.0	0.064	0.080	0.077	0.076	0.075	0.084	0.073	0.087	0.110	0.106	0.083
STATES REGULATING THE UTILITIES BELOW ARE New Jersey												
ATLANTIC CITY ELECTRIC	0.555	0.096	0.087	0.083	0.076	0.072	0.095	0.092	0.082	0.096	0.100	0.085
PUBLIC SERVICE ELEC & GAS	0.609	0.085	0.086	0.082	0.070	0.082	0.070	0.067	0.074	0.079	0.094	0.079
STATES REGULATING THE UTILITIES BELOW ARE New Mexico												
PUBLIC SERVICE CO OF N MEX	0.592	0.112	0.104	0.104	0.105	0.100	0.113	0.115	0.091	0.101	0.089	0.103
STATES REGULATING THE UTILITIES BELOW ARE New York												
LONG ISLAND LIGHTING	0.530	0.085	0.084	0.090	0.086	0.086	0.081	0.078	0.077	0.090	0.096	0.085
NIAGARA MOHAWK POWER	0.490	0.076	0.064	0.064	0.059	0.062	0.069	0.058	0.067	0.084	0.075	0.068
NEW YORK STATE ELEC & GAS	0.534	0.089	0.083	0.077	0.072	0.065	0.074	0.076	0.081	0.078	0.083	0.078
ORANGE & ROCKLAND UTILITIES	0.637	0.079	0.076	0.072	0.077	0.055	0.067	0.075	0.070	0.092	0.099	0.076
ROCHESTER GAS & ELECTRIC	0.606	0.085	0.078	0.074	0.070	0.069	0.071	0.089	0.069	0.082	0.086	0.077
CENTRAL HUDSON GAS & ELEC	0.480	0.081	0.082	0.078	0.061	0.083	0.090	0.083	0.065	0.086	0.092	0.080
CONSOLIDATED EDISON OF N.Y.	0.302	0.059	0.061	0.058	0.051	0.055	0.055	0.059	0.071	0.082	0.092	0.064
STATES REGULATING THE UTILITIES BELOW ARE Ohio												
CLEVELAND ELECTRIC ILLUM	0.384	0.128	0.129	0.117	0.103	0.097	0.093	0.086	0.096	0.088	0.092	0.103
OHIO EDISON CO	0.452	0.124	0.124	0.118	0.102	0.091	0.089	0.091	0.074	0.085	0.089	0.099
COLUMBUS & SOUTHERN OHIO	0.603	0.101	0.097	0.090	0.077	0.069	0.076	0.081	0.063	0.101	0.098	0.085
TOLEDO EDISON COMPANY	0.418	0.107	0.110	0.109	0.100	0.093	0.093	0.091	0.078	0.094	0.089	0.096
CINCINNATI GAS & ELECTRIC	0.284	0.123	0.123	0.118	0.104	0.096	0.102	0.099	0.082	0.082	0.083	0.101
DAYTON POWER & LIGHT	0.479	0.127	0.109	0.097	0.086	0.063	0.081	0.070	0.071	0.096	0.097	0.092
STATES REGULATING THE UTILITIES BELOW ARE Oregon												
PORTLAND GENERAL ELECTRIC CO	0.444	0.080	0.079	0.084	0.081	0.096	0.092	0.095	0.080	0.090	0.092	0.086
STATES REGULATING THE UTILITIES BELOW ARE Pennsylvania												
PENNSYLVANIA POWER & LIGHT	0.441	0.088	0.084	0.078	0.065	0.076	0.086	0.091	0.098	0.098	0.095	0.086
PHILADELPHIA ELECTRIC CO	0.438	0.091	0.084	0.082	0.074	0.083	0.084	0.083	0.092	0.089	0.093	0.085
DUQUESNE LIGHT CO	0.504	0.105	0.102	0.093	0.082	0.091	0.089	0.086	0.088	0.097	0.088	0.092
STATES REGULATING THE UTILITIES BELOW ARE South Carolina												
SOUTH CAROLINA ELEC & GAS	0.841	0.098	0.102	0.094	0.081	0.075	0.081	0.076	0.080	0.099	0.095	0.088
STATES REGULATING THE UTILITIES BELOW ARE TEXAS												
SOUTHWESTERN PUBLIC SERV CO	0.374	0.093	0.102	0.106	0.110	0.116	0.108	0.108	0.120	0.109	0.119	0.109
SOUTHWESTERN ELEC SERVICE	0.371	0.081	0.083	0.091	0.097	0.099	0.100	0.103	0.105	0.104	0.103	0.097
STATES REGULATING THE UTILITIES BELOW ARE Vermont												
GREEN MOUNTAIN POWER CORP	1.063	0.076	0.075	0.074	0.075	0.039	0.060	0.061	0.087	0.090	0.089	0.073

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
STATES REGULATING THE UTILITIES BELOW ARE			Washington									
PUGET SOUND POWER & LIGHT	0.476	0.060	0.063	0.061	0.063	0.066	0.073	0.072	0.091	0.092	0.091	0.073
STATES REGULATING THE UTILITIES BELOW ARE			Wisconsin									
MADISON GAS & ELECTRIC CO	0.367	0.077	0.079	0.088	0.077	0.080	0.077	0.094	0.089	0.113	0.108	0.088
WISCONSIN ELECTRIC POWER	0.140	0.097	0.085	0.092	0.084	0.088	0.105	0.118	0.108	0.106	0.116	0.100
WISCONSIN POWER & LIGHT	0.419	0.111	0.112	0.107	0.103	0.093	0.095	0.101	0.098	0.123	0.140	0.108
OKLAHOMA GAS & ELECTRIC	0.342	0.105	0.105	0.116	0.120	0.115	0.118	0.117	0.108	0.101	0.092	0.110
SIERRA PACIFIC POWER CO	0.502	0.068	0.070	0.068	0.073	0.074	0.078	0.083	0.089	0.085	0.101	0.079
STATES REGULATING THE UTILITIES BELOW ARE			Multistate									
UTAH POWER & LIGHT	0.344	0.080	0.080	0.076	0.075	0.076	0.082	0.077	0.074	0.085	0.107	0.081
STATES REGULATING THE UTILITIES BELOW ARE												
WASHINGTON WATER POWER	0.282	0.073	0.080	0.080	0.081	0.082	0.080	0.081	0.085	0.087	0.098	0.083
UNION ELECTRIC CO	0.400	0.081	0.082	0.083	0.087	0.072	0.065	0.074	0.069	0.090	0.099	0.080
SOUTHERN INDIANA GAS & ELEC	0.445	0.113	0.117	0.119	0.120	0.114	0.126	0.130	0.115	0.119	0.128	0.120
IOWA-ILLINOIS GAS & ELEC	0.734	0.113	0.105	0.099	0.088	0.075	0.110	0.095	0.098	0.105	0.112	0.100
EMPIRE DISTRICT ELECTRIC CO	0.326	0.111	0.115	0.104	0.109	0.097	0.094	0.094	0.094	0.098	0.102	0.102
STATES REGULATING THE UTILITIES BELOW ARE												
KANSAS CITY POWER & LIGHT	0.481	0.096	0.099	0.094	0.088	0.088	0.087	0.081	0.086	0.091	0.094	0.090
STATES REGULATING THE UTILITIES BELOW ARE												
GULF STATES UTILITIES CO	0.484	0.103	0.105	0.103	0.098	0.095	0.099	0.097	0.102	0.093	0.092	0.099
PUBLIC SERVICE CO OF N H	0.564	0.083	0.088	0.089	0.084	0.072	0.070	0.072	0.082	0.100	0.093	0.083
STATES REGULATING THE UTILITIES BELOW ARE												
POTOMAC ELECTRIC POWER	0.460	0.076	0.074	0.063	0.066	0.067	0.077	0.083	0.088	0.067	0.094	0.075
LAKE SUPERIOR DIST POWER CO	0.315	0.080	0.088	0.077	0.073	0.082	0.092	0.085	0.089	0.097	0.088	0.085
WISCONSIN PUBLIC SERVICE	0.291	0.106	0.097	0.091	0.091	0.086	0.099	0.105	0.106	0.127	0.147	0.105
IOWA ELECTRIC LIGHT & PWR	0.713	0.091	0.090	0.088	0.085	0.075	0.089	0.086	0.064	0.082	0.093	0.084
INTERSTATE POWER CO	0.436	0.090	0.091	0.093	0.088	0.083	0.089	0.087	0.088	0.089	0.088	0.089
PACIFIC POWER & LIGHT	0.487	0.065	0.067	0.068	0.070	0.078	0.081	0.077	0.071	0.078	0.082	0.074
STATES REGULATING THE UTILITIES BELOW ARE												
NORTHWESTERN PUBLIC SERV CO	0.392	0.089	0.088	0.093	0.097	0.103	0.099	0.090	0.088	0.083	0.096	0.093
STATES REGULATING THE UTILITIES BELOW ARE												
COMMUNITY PUBLIC SERVICE	0.435	0.065	0.089	0.097	0.102	0.104	0.109	0.107	0.096	0.096	0.107	0.099
EL PASO ELECTRIC CO	0.358	0.125	0.130	0.133	0.127	0.122	0.125	0.118	0.108	0.107	0.113	0.121
STATES REGULATING THE UTILITIES BELOW ARE												
CENTRAL VERMONT PUB SERV	0.766	0.076	0.070	0.067	0.062	0.051	0.064	0.032	0.064	0.091	0.091	0.067
STATES REGULATING THE UTILITIES BELOW ARE												
VIRGINIA ELECTRIC & POWER	0.617	0.096	0.097	0.093	0.084	0.076	0.074	0.079	0.069	0.068	0.090	0.085
OTTER TAIL POWER CO	0.281	0.086	0.079	0.087	0.090	0.105	0.103	0.099	0.088	0.091	0.105	0.093
NORTHERN STATES POWER	0.477	0.089	0.089	0.089	0.088	0.099	0.095	0.086	0.087	0.105	0.110	0.093
IDAHO POWER CO	0.363	0.074	0.081	0.087	0.092	0.096	0.094	0.086	0.096	0.081	0.093	0.088
STATES REGULATING THE UTILITIES BELOW ARE												
BANGOR HYDRO-ELEC CO	0.524	0.102	0.095	0.087	0.078	0.066	0.085	0.061	0.065	0.089	0.064	0.080
STATES REGULATING THE UTILITIES BELOW ARE												
BALTIMORE GAS & ELECTRIC	0.420	0.112	0.113	0.112	0.102	0.095	0.089	0.089	0.074	0.083	0.090	0.096
STATES REGULATING THE UTILITIES BELOW ARE												
DUKE POWER CO	0.612	0.108	0.105	0.094	0.066	0.071	0.069	0.077	0.085	0.098	0.111	0.088
CAROLINA POWER & LIGHT	0.609	0.096	0.099	0.091	0.066	0.078	0.099	0.082	0.075	0.102	0.118	0.091
IOWA PUBLIC SERVICE CO	0.304	0.103	0.110	0.103	0.093	0.100	0.087	0.084	0.087	0.102	0.106	0.097
STATES REGULATING THE UTILITIES BELOW ARE												
KENTUCKY UTILITIES CO	0.465	0.121	0.123	0.122	0.107	0.098	0.093	0.099	0.076	0.109	0.099	0.105
STATES REGULATING THE UTILITIES BELOW ARE												
MONTANA POWER CO	0.311	0.119	0.114	0.129	0.127	0.123	0.120	0.116	0.100	0.090	0.075	0.111
STATES REGULATING THE UTILITIES BELOW ARE												
BLACK HILLS POWER & LIGHT CO	0.428	0.083	0.084	0.081	0.077	0.098	0.102	0.104	0.099	0.101	0.091	0.092

TABLE NO. 5.2

RATE OF RETURN MEASURE 2

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
STATES REGULATING THE UTILITIES BELOW ARE			Ariz									
ARIZONA PUBLIC SERVICE CO	0.491	0.060	0.062	0.070	0.075	0.066	0.068	0.081	0.078	0.096	0.092	0.075
TUCSON GAS & ELECTRIC	0.532	0.092	0.094	0.094	0.096	0.077	0.070	0.069	0.063	0.101	0.112	0.087
STATES REGULATING THE UTILITIES BELOW ARE			Calif									
PACIFIC GAS & ELECTRIC	0.240	0.080	0.081	0.081	0.072	0.080	0.076	0.080	0.082	0.070	0.073	0.077
SAN DIEGO GAS & ELECTRIC	0.511	0.086	0.087	0.091	0.082	0.074	0.065	0.066	0.083	0.058	0.088	0.078
SOUTHERN CALIF EDISON CO	0.382	0.076	0.069	0.066	0.070	0.066	0.071	0.073	0.111	0.083	0.087	0.077
STATES REGULATING THE UTILITIES BELOW ARE			Colo									
PUBLIC SERVICE CO OF COLO	0.365	0.079	0.080	0.082	0.078	0.069	0.068	0.070	0.070	0.089	0.086	0.077
STATES REGULATING THE UTILITIES BELOW ARE			Conn.									
UNITED ILLUMINATING CO	0.412	0.088	0.079	0.093	0.085	0.063	0.092	0.067	0.088	0.074	0.074	0.080
STATES REGULATING THE UTILITIES BELOW ARE			Del									
DELMARVA POWER & LIGHT	0.472	0.099	0.099	0.090	0.070	0.064	0.065	0.074	0.087	0.075	0.071	0.079
STATES REGULATING THE UTILITIES BELOW ARE			Flor.									
FLORIDA POWER & LIGHT	0.575	0.110	0.116	0.114	0.103	0.097	0.083	0.103	0.097	0.138	0.097	0.106
FLORIDA POWER CORP	0.636	0.101	0.105	0.103	0.096	0.089	0.084	0.080	0.073	0.112	0.119	0.096
TAMPA ELECTRIC CO	0.773	0.100	0.098	0.096	0.087	0.072	0.092	0.094	0.079	0.113	0.113	0.094
STATES REGULATING THE UTILITIES BELOW ARE			Georgia									
SAVANNAH ELEC & POWER	0.537	0.085	0.093	0.087	0.078	0.061	0.060	0.067	0.087	0.103	0.103	0.082
STATES REGULATING THE UTILITIES BELOW ARE			Hawaii									
HAWAIIAN ELECTRIC CO	0.477	0.081	0.088	0.090	0.084	0.084	0.082	0.087	0.088	0.101	0.100	0.088
STATES REGULATING THE UTILITIES BELOW ARE			Ill									
ILLINOIS POWER CO	0.497	0.126	0.123	0.117	0.110	0.095	0.087	0.093	0.093	0.110	0.106	0.106
COMMONWEALTH EDISON	0.307	0.111	0.108	0.094	0.081	0.071	0.078	0.087	0.087	0.055	0.102	0.091
CENTRAL ILL PUBLIC SERVICE	0.567	0.112	0.115	0.113	0.102	0.095	0.082	0.087	0.093	0.059	0.098	0.100
CENTRAL ILLINOIS LIGHT	0.487	0.095	0.096	0.099	0.100	0.091	0.091	0.089	0.086	0.068	0.101	0.094
STATES REGULATING THE UTILITIES BELOW ARE			Ind									
PUBLIC SERVICE CO OF IND	0.423	0.112	0.115	0.110	0.102	0.088	0.103	0.119	0.122	0.119	0.142	0.113
NORTHERN INDIANA PUBLIC SERV	0.337	0.113	0.112	0.117	0.116	0.101	0.096	0.096	0.090	0.103	0.107	0.105
INDIANAPOLIS POWER & LIGHT	0.694	0.110	0.107	0.099	0.100	0.099	0.107	0.098	0.089	0.105	0.120	0.103
STATES REGULATING THE UTILITIES BELOW ARE			Iowa									
IOWA POWER & LIGHT	0.353	0.094	0.091	0.087	0.076	0.084	0.082	0.100	0.093	0.108	0.109	0.092
IOWA SOUTHERN UTILITIES CO	0.571	0.106	0.112	0.129	0.127	0.123	0.127	0.115	0.117	0.107	0.112	0.117
STATES REGULATING THE UTILITIES BELOW ARE			Kan.									
KANSAS POWER & LIGHT	0.281	0.102	0.110	0.114	0.110	0.113	0.113	0.112	0.093	0.101	0.102	0.107
KANSAS GAS & ELECTRIC	0.558	0.105	0.110	0.116	0.107	0.092	0.081	0.079	0.086	0.111	0.116	0.100
STATES REGULATING THE UTILITIES BELOW ARE			Ken.									
LOUISVILLE GAS & ELECTRIC	0.436	0.132	0.140	0.142	0.132	0.123	0.112	0.115	0.105	0.122	0.129	0.125
STATES REGULATING THE UTILITIES BELOW ARE			Me.									

CENTRAL MAINE POWER CO	0.310	0.097	0.095	0.090	0.091	0.082	0.096	0.090	0.078	0.086	0.094	0.090
MAINE PUBLIC SERVICE	0.491	0.079	0.077	0.085	0.090	0.078	0.083	0.097	0.107	0.093	0.106	0.089
STATES REGULATING THE UTILITIES BELOW ARE			MASS									
BOSTON EDISON CO	0.525	0.089	0.089	0.080	0.063	0.056	0.046	0.069	0.083	0.090	0.091	0.076
FITCHBURG GAS & ELEC LIGHT	0.387	0.078	0.087	0.083	0.083	0.082	0.083	0.074	0.074	0.082	0.096	0.082
STATES REGULATING THE UTILITIES BELOW ARE			Mich									
EDISON SAULT ELECTRIC	0.0	0.113	0.114	0.101	0.089	0.078	0.080	0.094	0.109	0.083	0.082	0.094
DETROIT EDISON CO	0.714	0.086	0.081	0.081	0.064	0.060	0.063	0.066	0.069	0.069	0.075	0.072
UPPER PENINSULA POWER	0.440	0.086	0.086	0.086	0.074	0.072	0.094	0.097	0.069	0.074	0.098	0.084
CONSUMERS POWER CO	0.711	0.104	0.096	0.088	0.082	0.066	0.065	0.069	0.058	0.064	0.100	0.081
STATES REGULATING THE UTILITIES BELOW ARE			MINN									
MINNESOTA POWER & LIGHT	0.390	0.084	0.094	0.088	0.079	0.075	0.064	0.076	0.086	0.102	0.108	0.086
STATES REGULATING THE UTILITIES BELOW ARE			Missouri									
MISSOURI PUBLIC SERVICE CO	0.631	0.083	0.068	0.073	0.089	0.077	0.082	0.080	0.094	0.100	0.111	0.086
ST JOSEPH LIGHT & POWER	0.599	0.080	0.089	0.085	0.095	0.106	0.102	0.093	0.094	0.096	0.101	0.094
STATES REGULATING THE UTILITIES BELOW ARE			Nev									
NEVADA POWER CO	0.650	0.092	0.087	0.085	0.074	0.075	0.082	0.073	0.085	0.067	0.086	0.080
STATES REGULATING THE UTILITIES BELOW ARE			N.H.									
CONCORD ELECTRIC CO	0.0	0.063	0.079	0.076	0.075	0.073	0.082	0.073	0.088	0.110	0.105	0.082
STATES REGULATING THE UTILITIES BELOW ARE			N.J.									
ATLANTIC CITY ELECTRIC	0.555	0.084	0.085	0.077	0.067	0.060	0.070	0.076	0.081	0.103	0.111	0.081
PUBLIC SERVICE ELEC & GAS	0.609	0.083	0.082	0.077	0.062	0.070	0.056	0.058	0.074	0.084	0.107	0.075
STATES REGULATING THE UTILITIES BELOW ARE			NM									
PUBLIC SERVICE CO OF N MEX	0.592	0.108	0.098	0.099	0.102	0.097	0.103	0.107	0.093	0.114	0.102	0.103
STATES REGULATING THE UTILITIES BELOW ARE			N.Y.									
LONG ISLAND LIGHTING	0.530	0.082	0.081	0.088	0.081	0.079	0.073	0.077	0.079	0.094	0.107	0.084
NIAGARA MOHAWK POWER	0.490	0.071	0.057	0.057	0.054	0.058	0.062	0.054	0.066	0.086	0.078	0.064
NEW YORK STATE ELEC & GAS	0.534	0.086	0.077	0.067	0.067	0.063	0.071	0.076	0.084	0.080	0.089	0.076
ORANGE & ROCKLAND UTILITIES	0.637	0.078	0.071	0.065	0.073	0.046	0.056	0.074	0.072	0.092	0.100	0.073
ROCHESTER GAS & ELECTRIC	0.606	0.081	0.069	0.062	0.063	0.068	0.070	0.090	0.070	0.085	0.098	0.075
CENTRAL HUDSON GAS & ELEC	0.480	0.074	0.080	0.076	0.057	0.075	0.077	0.080	0.062	0.089	0.094	0.076
CONSOLIDATED EDISON OF N.Y.	0.802	0.057	0.057	0.054	0.045	0.048	0.046	0.056	0.073	0.083	0.095	0.061
STATES REGULATING THE UTILITIES BELOW ARE			Ohio									
CLEVELAND ELECTRIC ILLUM	0.394	0.126	0.123	0.107	0.092	0.090	0.084	0.085	0.107	0.096	0.103	0.101
OHIO EDISON CO	0.432	0.119	0.118	0.115	0.097	0.083	0.080	0.090	0.077	0.091	0.095	0.096
COLUMBUS & SOUTHERN OHIO	0.603	0.099	0.092	0.083	0.067	0.061	0.066	0.077	0.063	0.113	0.102	0.082
TOLEDO EDISON COMPANY	0.418	0.103	0.106	0.107	0.096	0.035	0.082	0.086	0.084	0.115	0.111	0.097
CINCINNATI GAS & ELECTRIC	0.214	0.120	0.119	0.110	0.094	0.087	0.092	0.097	0.085	0.085	0.086	0.097
DAYTON POWER & LIGHT	0.479	0.124	0.102	0.088	0.077	0.077	0.074	0.067	0.071	0.100	0.102	0.088
STATES REGULATING THE UTILITIES BELOW ARE			Or.									
PORTLAND GENERAL ELECTRIC CO	0.444	0.077	0.077	0.083	0.079	0.092	0.083	0.082	0.084	0.101	0.105	0.086
STATES REGULATING THE UTILITIES BELOW ARE			Penn									
PENNSYLVANIA POWER & LIGHT	0.441	0.083	0.077	0.071	0.056	0.063	0.076	0.087	0.105	0.101	0.100	0.082
PHILADELPHIA ELECTRIC CO	0.438	0.088	0.082	0.078	0.064	0.069	0.068	0.077	0.086	0.096	0.102	0.081
DUQUESNE LIGHT CO	0.504	0.101	0.098	0.083	0.067	0.080	0.075	0.083	0.097	0.112	0.095	0.089
STATES REGULATING THE UTILITIES BELOW ARE			S.C.									
SOUTH CAROLINA ELEC & GAS	0.941	0.095	0.099	0.086	0.069	0.065	0.071	0.070	0.082	0.106	0.106	0.085
STATES REGULATING THE UTILITIES BELOW ARE			Tex.									
SOUTHWESTERN PUBLIC SERV CO	0.374	0.092	0.098	0.106	0.107	0.111	0.107	0.110	0.124	0.116	0.121	0.109
SOUTHWESTERN ELEC SERVICE	0.371	0.080	0.082	0.091	0.096	0.098	0.099	0.103	0.105	0.104	0.103	0.096
STATES REGULATING THE UTILITIES BELOW ARE			Ver									
GREEN MOUNTAIN POWER CORP	1.063	0.074	0.068	0.063	0.064	0.027	0.050	0.061	0.088	0.091	0.090	0.068
STATES REGULATING THE UTILITIES BELOW ARE			WASH									
PUGET SOUND POWER & LIGHT	0.476	0.058	0.061	0.060	0.061	0.062	0.070	0.071	0.096	0.092	0.092	0.072
STATES REGULATING THE UTILITIES BELOW ARE			Wis.									
MADISON GAS & ELECTRIC CO	0.367	0.076	0.077	0.084	0.070	0.066	0.061	0.091	0.100	0.124	0.116	0.086
WISCONSIN ELECTRIC POWER	0.140	0.097	0.085	0.086	0.076	0.083	0.101	0.118	0.110	0.110	0.121	0.099
WISCONSIN POWER & LIGHT	0.419	0.110	0.109	0.099	0.098	0.083	0.083	0.100	0.107	0.136	0.151	0.108
OKLAHOMA GAS & ELECTRIC	0.342	0.103	0.101	0.112	0.114	0.111	0.114	0.119	0.117	0.111	0.101	0.110
SIERRA PACIFIC POWER CO	0.502	0.065	0.065	0.067	0.069	0.069	0.076	0.062	0.085	0.084	0.101	0.076
~~STATES REGULATING THE UTILITIES BELOW ARE~~			Multistate	50								
UTAH POWER & LIGHT	0.344	0.078	0.076	0.075	0.069	0.069	0.077	0.075	0.073	0.087	0.114	0.079
~~STATES REGULATING THE UTILITIES BELOW ARE~~			43	12	26							
WASHINGTON WATER POWER	0.282	0.073	0.078	0.079	0.078	0.077	0.074	0.081	0.084	0.088	0.098	0.081
UNION ELECTRIC CO	0.400	0.076	0.077	0.075	0.077	0.062	0.056	0.072	0.065	0.093	0.109	0.077
SOUTHERN INDIANA GAS & ELEC	0.445	0.113	0.116	0.113	0.112	0.109	0.111	0.122	0.118	0.122	0.133	0.117
IOWA-ILLINOIS GAS & ELEC	0.734	0.108	0.098	0.088	0.074	0.063	0.098	0.095	0.098	0.104	0.114	0.094
EMPIRE DISTRICT ELECTRIC CO	0.326	0.110	0.113	0.091	0.101	0.096	0.093	0.093	0.094	0.098	0.103	0.099
~~STATES REGULATING THE UTILITIES BELOW ARE~~			25	16								
KANSAS CITY POWER & LIGHT	0.481	0.094	0.092	0.090	0.085	0.082	0.077	0.078	0.089	0.095	0.104	0.089
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
GULF STATES UTILITIES CO	0.464	0.100	0.098	0.095	0.098	0.087	0.090	0.095	0.105	0.100	0.100	0.096
PUBLIC SERVICE CO OF N H	0.364	0.077	0.084	0.086	0.078	0.068	0.062	0.066	0.084	0.101	0.094	0.080
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
POTOMAC ELECTRIC POWER	0.460	0.076	0.074	0.063	0.066	0.067	0.077	0.090	0.107	0.081	0.110	0.081
LAKE SUPERIOR DIST POWER CO	0.315	0.080	0.087	0.075	0.072	0.082	0.091	0.089	0.097	0.099	0.089	0.086
WISCONSIN PUBLIC SERVICE	0.291	0.105	0.094	0.084	0.085	0.076	0.086	0.105	0.118	0.138	0.156	0.105
IOWA ELECTRIC LIGHT & PWR	0.713	0.084	0.087	0.087	0.090	0.065	0.071	0.071	0.062	0.082	0.093	0.079
INTERSTATE POWER CO	0.436	0.086	0.090	0.093	0.086	0.088	0.088	0.088	0.090	0.093	0.093	0.089
PACIFIC POWER & LIGHT	0.487	0.064	0.065	0.066	0.063	0.067	0.069	0.076	0.071	0.075	0.083	0.070
~~STATES REGULATING THE UTILITIES BELOW ARE~~			41	37								
NORTHWESTERN PUBLIC SERV CO	0.392	0.088	0.087	0.092	0.096	0.100	0.091	0.091	0.099	0.091	0.099	0.093
~~STATES REGULATING THE UTILITIES BELOW ARE~~			43	31								
COMMUNITY PUBLIC SERVICE	0.435	0.083	0.089	0.096	0.101	0.103	0.108	0.107	0.095	0.096	0.108	0.099
EL PASO ELECTRIC CO	0.358	0.123	0.123	0.128	0.124	0.118	0.120	0.120	0.116	0.111	0.117	0.120
~~STATES REGULATING THE UTILITIES BELOW ARE~~			45	32								
CENTRAL VERMONT PUB SERV	0.756	0.074	0.064	0.057	0.052	0.040	0.055	0.031	0.065	0.094	0.095	0.063
~~STATES REGULATING THE UTILITIES~~ BELOW ARE			46	33	48							
VIRGINIA ELECTRIC & POWER	0.617	0.095	0.091	0.083	0.070	0.056	0.049	0.068	0.066	0.096	0.101	0.077
OTTER TAIL POWER CO	0.251	0.085	0.079	0.086	0.090	0.103	0.097	0.102	0.103	0.104	0.106	0.096
NORTHERN STATES POWER	0.477	0.083	0.085	0.082	0.078	0.076	0.080	0.075	0.087	0.111	0.117	0.087
IDAHO POWER CO	0.363	0.068	0.081	0.087	0.091	0.095	0.090	0.084	0.090	0.083	0.095	0.086
~~STATES REGULATING THE UTILITIES BELOW ARE~~			15	38								
BANGOR HYDRO-ELEC CO	0.524	0.100	0.093	0.083	0.072	0.066	0.085	0.061	0.070	0.090	0.063	0.078
~~STATES REGULATING THE UTILITIES BELOW ARE~~			29	38								
BALTIMORE GAS & ELECTRIC	0.420	0.112	0.111	0.107	0.094	0.091	0.069	0.094	0.079	0.103	0.103	0.094
~~STATES REGULATING THE UTILITIES BELOW ARE~~			33	40								
DUKE POWER CO	0.612	0.104	0.096	0.082	0.050	0.052	0.047	0.065	0.084	0.101	0.123	0.080
CAROLINA POWER & LIGHT	0.609	0.090	0.094	0.085	0.053	0.064	0.080	0.072	0.073	0.112	0.137	0.086
IOWA PUBLIC SERVICE CO	0.304	0.102	0.109	0.100	0.087	0.090	0.080	0.085	0.089	0.102	0.110	0.095
~~STATES REGULATING THE UTILITIES BELOW ARE~~			17	42								
KENTUCKY UTILITIES CO	0.465	0.121	0.121	0.117	0.097	0.090	0.085	0.099	0.085	0.116	0.107	0.104
~~STATES REGULATING THE UTILITIES BELOW ARE~~			23	50								
MONTANA POWER CO	0.311	0.116	0.111	0.128	0.127	0.122	0.118	0.118	0.104	0.091	0.074	0.111

~~STATES REGULATING THE UTILITIES BELOW ARE~~			~~41~~	~~30~~	~~26~~	~~27~~						
BLACK HILLS POWER & LIGHT CO	0.428	0.083	0.083	0.076	0.077	0.098	0.102	0.105	0.107	0.106	0.102	0.094

TABLE NO. 63

RATE OF RETURN MEASURE 3

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
STATES REGULATING THE UTILITIES BELOW ARE			ARIZ									
ARIZONA PUBLIC SERVICE CO	0.491	0.102	0.120	0.134	0.143	0.124	0.124	0.131	0.105	0.146	0.117	0.125
TUCSON GAS & ELECTRIC	0.532	0.180	0.179	0.183	0.185	0.144	0.139	0.122	0.063	0.158	0.166	0.15?
STATES REGULATING THE UTILITIES BELOW ARE			CAL									
PACIFIC GAS & ELECTRIC	0.240	0.161	0.158	0.154	0.131	0.149	0.142	0.135	0.120	0.086	0.090	0.13
SAN DIEGO GAS & ELECTRIC	0.511	0.165	0.169	0.178	0.147	0.129	0.090	0.081	0.110	0.042	0.125	0.12
~~SOUTHERN CALIF EDISON CO~~	~~0.392~~	~~0.143~~	~~0.125~~	~~0.120~~	~~0.123~~	~~0.109~~	~~0.112~~	~~0.111~~	~~0.197~~	~~0.123~~	~~0.127~~	~~0.129~~
STATES REGULATING THE UTILITIES BELOW ARE			COL									
PUBLIC SERVICE CO OF COLO	0.365	0.158	0.165	0.161	0.150	0.128	0.134	0.129	0.094	0.158	0.141	0.14
STATES REGULATING THE UTILITIES BELOW ARE			CONN.									
UNITED ILLUMINATING CO	0.412	0.205	0.186	0.203	0.174	0.107	0.213	0.118	0.145	0.111	0.102	0.15
~~STATES REGULATING THE UTILITIES BELOW ARE~~			DEL									
DELMARVA POWER & LIGHT	0.472	0.203	0.216	0.194	0.138	0.138	0.130	0.124	0.117	0.090	0.082	0.143
STATES REGULATING THE UTILITIES BELOW ARE			Fl									
~~FLORIDA POWER & LIGHT~~	~~0.575~~	~~0.187~~	~~0.203~~	~~0.194~~	~~0.171~~	~~0.183~~	~~0.164~~	~~0.178~~	~~0.135~~	~~0.205~~	~~0.134~~	~~0.17~~
FLORIDA POWER CORP	0.636	0.192	0.206	0.210	0.183	0.171	0.174	0.147	0.091	0.169	0.155	0.17
TAMPA ELECTRIC CO	0.773	0.228	0.203	0.198	0.180	0.118	0.179	0.170	0.105	0.179	0.177	0.17
~~STATES REGULATING THE UTILITIES BELOW ARE~~			GA									
SAVANNAH ELEC & POWER	0.537	0.162	0.183	0.173	0.153	0.115	0.099	0.078	0.093	0.137	0.118	0.131
STATES REGULATING THE UTILITIES BELOW ARE			Ha.									
~~HAWAIIAN ELECTRIC CO~~	~~0.477~~	~~0.142~~	~~0.163~~	~~0.162~~	~~0.147~~	~~0.135~~	~~0.129~~	~~0.132~~	~~0.135~~	~~0.158~~	~~0.155~~	~~0.14~~
STATES REGULATING THE UTILITIES BELOW ARE			IL									
ILLINOIS POWER CO	0.497	0.274	0.274	0.270	0.244	0.186	0.165	0.164	0.143	0.179	0.151	0.205
~~COMMONWEALTH EDISON~~	~~0.307~~	~~0.219~~	~~0.215~~	~~0.191~~	~~0.164~~	~~0.144~~	~~0.161~~	~~0.154~~	~~0.134~~	~~0.148~~	~~0.147~~	~~0.163~~
CENTRAL ILL PUBLIC SERVICE	0.567	0.245	0.245	0.238	0.208	0.198	0.158	0.145	0.145	0.159	0.145	0.189
CENTRAL ILLINOIS LIGHT	0.487	0.187	0.186	0.192	0.203	0.187	0.175	0.141	0.112	0.111	0.153	0.16
~~STATES REGULATING THE UTILITIES BELOW ARE~~			IN									
PUBLIC SERVICE CO OF IND	0.423	0.210	0.223	0.217	0.205	0.165	0.196	0.205	0.193	0.180	0.232	0.20
NORTHERN INDIANA PUBLIC SERV	0.337	0.247	0.241	0.231	0.240	0.197	0.200	0.181	0.136	0.164	0.191	0.20
INDIANAPOLIS POWER & LIGHT	0.694	0.247	0.246	0.238	0.213	0.208	0.239	0.194	0.136	0.168	0.180	0.207
STATES REGULATING THE UTILITIES BELOW ARE			IO.									
IOWA POWER & LIGHT	0.353	0.208	0.202	0.190	0.145	0.160	0.150	0.185	0.154	0.159	0.178	0.17
IOWA SOUTHERN UTILITIES CO	0.571	0.222	0.230	0.245	0.230	0.218	0.222	0.186	0.171	0.174	0.163	0.20
STATES REGULATING THE UTILITIES BELOW ARE			KA									
KANSAS POWER & LIGHT	0.281	0.190	0.202	0.211	0.217	0.211	0.194	0.188	0.148	0.160	0.151	0.187
KANSAS GAS & ELECTRIC	0.558	0.222	0.221	0.236	0.214	0.189	0.170	0.143	0.134	0.193	0.183	0.190
STATES REGULATING THE UTILITIES BELOW ARE			KE.									
LOUISVILLE GAS & ELECTRIC	0.436	0.247	0.263	0.267	0.240	0.223	0.198	0.188	0.155	0.195	0.184	0.21
STATES REGULATING THE UTILITIES BELOW ARE			Me									
CENTRAL MAINE POWER CO	0.310	0.191	0.186	0.176	0.174	0.144	0.174	0.153	0.117	0.136	0.145	0.160
MAINE PUBLIC SERVICE	0.491	0.144	0.135	0.154	0.155	0.124	0.137	0.173	0.202	0.162	0.190	0.158
~~STATES REGULATING THE UTILITIES BELOW ARE~~			Ms									
BOSTON EDISON CO	0.525	0.167	0.168	0.157	0.126	0.109	0.091	0.089	0.096	0.115	0.110	0.12
FITCHBURG GAS & ELEC LIGHT	0.387	0.133	0.151	0.126	0.116	0.112	0.125	0.099	0.071	0.115	0.141	0.11
~~STATES REGULATING THE UTILITIES BELOW ARE~~			Mich									
EDISON SAULT ELECTRIC	0.0	0.232	0.225	0.192	0.160	0.130	0.136	0.166	0.197	0.138	0.116	0.169
DETROIT EDISON CO	0.714	0.160	0.155	0.153	0.118	0.107	0.121	0.103	0.084	0.088	0.088	0.118
UPPER PENINSULA POWER	0.440	0.169	0.164	0.157	0.123	0.121	0.176	0.175	0.088	0.115	0.182	0.147
~~CONSUMERS POWER CO~~	~~0.711~~	~~0.198~~	~~0.186~~	~~0.170~~	~~0.157~~	~~0.121~~	~~0.115~~	~~0.107~~	~~0.055~~	~~0.114~~	~~0.150~~	~~0.13~~
STATES REGULATING THE UTILITIES BELOW ARE			Mn									
MINNESOTA POWER & LIGHT	0.390	0.170	0.196	0.184	0.166	0.175	0.161	0.156	0.150	0.195	0.184	0.17
STATES REGULATING THE UTILITIES BELOW ARE			Mo.									
MISSOURI PUBLIC SERVICE CO	0.631	0.215	0.194	0.194	0.201	0.161	0.186	0.144	0.173	0.150	0.216	0.187
ST JOSEPH LIGHT & POWER	0.599	0.179	0.209	0.175	0.187	0.220	0.205	0.158	0.148	0.154	0.153	0.17?
STATES REGULATING THE UTILITIES BELOW ARE			Ne									
NEVADA POWER CO	0.650	0.157	0.166	0.162	0.137	0.128	0.153	0.106	0.096	0.058	0.111	0.12
~~STATES REGULATING THE UTILITIES BELOW ARE~~			NH									
CONCORD ELECTRIC CO	0.0	0.100	0.139	0.128	0.122	0.126	0.142	0.103	0.133	0.220	0.188	0.140
STATES REGULATING THE UTILITIES BELOW ARE			NJ									
~~ATLANTIC CITY ELECTRIC~~	~~0.555~~	~~0.190~~	~~0.197~~	~~0.176~~	~~0.139~~	~~0.120~~	~~0.148~~	~~0.137~~	~~0.122~~	~~0.167~~	~~0.169~~	~~0.15~~
PUBLIC SERVICE ELEC & GAS	0.609	0.159	0.160	0.142	0.104	0.130	0.089	0.083	0.103	0.120	0.161	0.12
STATES REGULATING THE UTILITIES BELOW ARE			NM									
~~PUBLIC SERVICE CO OF N MEX~~	~~0.592~~	~~0.216~~	~~0.203~~	~~0.197~~	~~0.192~~	~~0.176~~	~~0.195~~	~~0.195~~	~~0.137~~	~~0.160~~	~~0.128~~	~~0.180~~
STATES REGULATING THE UTILITIES BELOW ARE			NY									
LONG ISLAND LIGHTING	0.530	0.178	0.171	0.188	0.168	0.167	0.143	0.129	0.115	0.146	0.154	0.15
~~NIAGARA MOHAWK POWER~~	~~0.490~~	~~0.153~~	~~0.115~~	~~0.115~~	~~0.094~~	~~0.100~~	~~0.120~~	~~0.074~~	~~0.091~~	~~0.130~~	~~0.098~~	~~0.10~~
NEW YORK STATE ELEC & GAS	0.534	0.178	0.168	0.140	0.120	0.094	0.117	0.123	0.124	0.114	0.127	0.13
ORANGE & ROCKLAND UTILITIES	0.637	0.177	0.169	0.139	0.158	0.050	0.082	0.108	0.082	0.147	0.169	0.12
ROCHESTER GAS & ELECTRIC	0.606	0.170	0.149	0.128	0.109	0.106	0.112	0.151	0.087	0.120	0.127	0.126
~~CENTRAL HUDSON GAS & ELEC~~	~~0.490~~	~~0.170~~	~~0.171~~	~~0.152~~	~~0.089~~	~~0.163~~	~~0.183~~	~~0.142~~	~~0.068~~	~~0.136~~	~~0.154~~	~~0.143~~
CONSOLIDATED EDISON OF N.Y.	0.802	0.099	0.102	0.090	0.059	0.069	0.063	0.072	0.097	0.130	0.150	0.093
STATES REGULATING THE UTILITIES BELOW ARE			Oh									
~~CLEVELAND ELECTRIC ILLUM~~	~~0.384~~	~~0.228~~	~~0.238~~	~~0.221~~	~~0.190~~	~~0.172~~	~~0.169~~	~~0.145~~	~~0.175~~	~~0.141~~	~~0.153~~	~~0.18~~
OHIO EDISON CO	0.432	0.241	0.236	0.225	0.185	0.158	0.153	0.159	0.103	0.127	0.131	0.17
COLUMBUS & SOUTHERN OHIO	0.603	0.201	0.193	0.175	0.128	0.097	0.122	0.126	0.055	0.181	0.154	0.143
TOLEDO EDISON COMPANY	0.418	0.247	0.257	0.250	0.221	0.202	0.202	0.178	0.117	0.167	0.147	0.199
~~CINCINNATI GAS & ELECTRIC~~	[illegible]	~~0.255~~	~~0.258~~	~~0.246~~	~~0.214~~	~~0.184~~	~~0.201~~	~~0.189~~	~~0.134~~	~~0.127~~	~~0.125~~	~~0.153~~
DAYTON POWER & LIGHT	0.479	0.277	0.236	0.212	0.161	0.154	0.142	0.103	0.096	0.166	0.160	0.17
STATES REGULATING THE UTILITIES BELOW ARE			Or									
~~PORTLAND GENERAL ELECTRIC CO~~	~~0.444~~	~~0.129~~	~~0.12~~	~~0.139~~	~~0.121~~	~~0.153~~	~~0.141~~	~~0.118~~	~~0.112~~	~~0.136~~	~~0.133~~	~~0.13~~
STATES REGULATING THE UTILITIES BELOW ARE			Pe									
PENNSYLVANIA POWER & LIGHT	0.441	0.199	0.161	0.154	0.099	0.130	0.156	0.160	0.180	0.177	0.153	0.159
~~PHILADELPHIA ELECTRIC CO~~	~~0.439~~	~~0.175~~	~~0.154~~	~~0.143~~	~~0.113~~	~~0.137~~	~~0.134~~	~~0.125~~	~~0.114~~	~~0.127~~	~~0.130~~	~~0.135~~
DUQUESNE LIGHT CO	0.504	0.244	0.236	0.208	0.154	0.173	0.156	0.132	0.126	0.148	0.116	0.16
STATES REGULATING THE UTILITIES BELOW ARE			SC									
~~SOUTH CAROLINA ELEC & GAS~~	~~0.341~~	~~0.194~~	~~0.206~~	~~0.180~~	~~0.135~~	~~0.106~~	~~0.115~~	~~0.101~~	~~0.108~~	~~0.165~~	~~0.144~~	~~0.14~~
STATES REGULATING THE UTILITIES BELOW ARE			Tex									
SOUTHWESTERN PUBLIC SERV CO	0.374	0.199	0.219	0.230	0.238	0.239	0.209	0.213	0.248	0.217	0.245	0.226
~~SOUTHWESTERN ELEC SERVICE~~	~~0.371~~	~~0.180~~	~~0.183~~	~~0.208~~	~~0.218~~	~~0.212~~	~~0.210~~	~~0.213~~	~~0.210~~	~~0.205~~	~~0.190~~	~~0.20?~~
STATES REGULATING THE UTILITIES BELOW ARE			Ve.									
GREEN MOUNTAIN POWER CORP	1.063	0.163	0.150	0.136	0.095	0.003	0.088	0.049	0.135	0.155	0.166	0.11

STATES REGULATING THE UTILITIES BELOW ARE Wa.												
PUGET SOUND POWER & LIGHT	0.476	0.096	0.101	0.090	0.087	0.095	0.115	0.105	0.151	0.151	0.142	0.113
STATES REGULATING THE UTILITIES BELOW ARE Wi.												
MADISON GAS & ELECTRIC CO	0.367	0.118	0.122	0.140	0.117	0.128	0.119	0.160	0.138	0.157	0.171	0.141
WISCONSIN ELECTRIC POWER	0.140	0.187	0.155	0.170	0.146	0.158	0.209	0.239	0.195	0.193	0.197	0.185
WISCONSIN POWER & LIGHT	0.419	0.225	0.234	0.224	0.213	0.177	0.178	0.180	0.163	0.233	0.264	0.209
OKLAHOMA GAS & ELECTRIC	0.342	0.226	0.230	0.259	0.260	0.237	0.229	0.221	0.186	0.165	0.144	0.216
SIERRA PACIFIC POWER CO	0.502	0.114	0.113	0.104	0.103	0.110	0.121	0.126	0.128	0.118	0.163	0.120
~~STATES REGULATING THE UTILITIES BELOW ARE~~ Multistate												
UTAH POWER & LIGHT	0.344	0.153	0.151	0.138	0.129	0.127	0.143	0.115	0.096	0.125	0.172	0.135
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
WASHINGTON WATER POWER	0.252	0.135	0.156	0.156	0.146	0.144	0.137	0.137	0.142	0.149	0.173	0.147
UNION ELECTRIC CO	0.400	0.171	0.163	0.164	0.167	0.110	0.086	0.110	0.096	0.156	0.187	0.140
SOUTHERN INDIANA GAS & ELEC	0.445	0.218	0.231	0.232	0.227	0.214	0.236	0.236	0.197	0.198	0.213	0.220
IOWA-ILLINOIS GAS & ELEC	0.734	0.215	0.207	0.196	0.157	0.120	0.214	0.158	0.162	0.181	0.187	0.180
EMPIRE DISTRICT ELECTRIC CO	0.326	0.209	0.221	0.209	0.209	0.170	0.161	0.153	0.147	0.156	0.165	0.180
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
KANSAS CITY POWER & LIGHT	0.481	0.182	0.190	0.178	0.156	0.155	0.148	0.131	0.143	0.152	0.151	0.159
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
GULF STATES UTILITIES CO	0.484	0.216	0.221	0.205	0.188	0.163	0.178	0.172	0.176	0.152	0.145	0.182
PUBLIC SERVICE CO OF N H	0.564	0.165	0.185	0.192	0.166	0.118	0.116	0.104	0.105	0.172	0.142	0.146
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
POTOMAC ELECTRIC POWER	0.460	0.144	0.133	0.095	0.094	0.095	0.127	0.140	0.143	0.071	0.159	0.120
LAKE SUPERIOR DIST POWER CO	0.315	0.149	0.169	0.140	0.124	0.147	0.174	0.155	0.156	0.175	0.141	0.153
WISCONSIN PUBLIC SERVICE	0.291	0.232	0.213	0.196	0.199	0.154	0.185	0.194	0.183	0.248	0.295	0.210
IOWA ELECTRIC LIGHT & PWR	0.713	0.176	0.174	0.167	0.156	0.126	0.163	0.130	0.045	0.116	0.148	0.140
INTERSTATE POWER CO	0.436	0.204	0.201	0.209	0.199	0.190	0.193	0.194	0.186	0.179	0.156	0.190
PACIFIC POWER & LIGHT	0.487	0.108	0.113	0.114	0.112	0.137	0.142	0.125	0.090	0.112	0.117	0.117
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
NORTHWESTERN PUBLIC SERV CO	0.392	0.176	0.173	0.181	0.192	0.208	0.196	0.157	0.137	0.107	0.168	0.169
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
COMMUNITY PUBLIC SERVICE	0.435	0.162	0.174	0.188	0.185	0.187	0.202	0.193	0.144	0.151	0.179	0.176
EL PASO ELECTRIC CO	0.358	0.232	0.246	0.254	0.233	0.223	0.230	0.212	0.196	0.186	0.190	0.220
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
CENTRAL VERMONT PUB SERV	0.766	0.164	0.131	0.110	0.060	0.051	0.086	-0.004	0.065	0.131	0.135	0.093
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
VIRGINIA ELECTRIC & POWER	0.617	0.193	0.189	0.175	0.150	0.114	0.106	0.111	0.072	0.120	0.124	0.135
OTTER TAIL POWER CO	0.291	0.173	0.152	0.168	0.173	0.212	0.203	0.164	0.138	0.152	0.187	0.174
NORTHERN STATES POWER	0.477	0.199	0.202	0.197	0.179	0.176	0.190	0.151	0.144	0.192	0.192	0.182
IDAHO POWER CO	0.363	0.131	0.148	0.160	0.169	0.180	0.174	0.147	0.147	0.112	0.143	0.151
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
BANGOR HYDRO-ELEC CO	0.524	0.213	0.192	0.176	0.145	0.111	0.169	0.100	0.118	0.178	0.079	0.148
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
BALTIMORE GAS & ELECTRIC	0.420	0.240	0.247	0.238	0.196	0.173	0.150	0.148	0.098	0.123	0.140	0.175
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
DUKE POWER CO	0.612	0.216	0.216	0.186	0.093	0.109	0.091	0.113	0.121	0.152	0.188	0.148
CAROLINA POWER & LIGHT	0.609	0.136	0.201	0.165	0.091	0.124	0.182	0.115	0.086	0.167	0.195	0.152
IOWA PUBLIC SERVICE CO	0.304	0.200	0.213	0.197	0.169	0.188	0.147	0.139	0.153	0.180	0.168	0.175
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
KENTUCKY UTILITIES CO	0.465	0.203	0.204	0.207	0.178	0.160	0.149	0.155	0.100	0.182	0.148	0.169
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
MONTANA POWER CO	0.311	0.200	0.190	0.221	0.213	0.203	0.194	0.187	0.154	0.139	0.094	0.179
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
BLACK HILLS POWER & LIGHT CO	0.428	0.143	0.147	0.136	0.122	0.172	0.170	0.170	0.169	0.162	0.154	0.154

TABLE NO. 54

RATE OF RETURN MEASURE 4

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
STATES REGULATING THE UTILITIES BELOW ARE Ar												
ARIZONA PUBLIC SERVICE CO	0.491	0.098	0.104	0.122	0.139	0.115	0.106	0.149	0.164	0.374	0.284	0.165
TUCSON GAS & ELECTRIC	0.532	0.169	0.172	0.170	0.176	0.124	0.097	0.118	-0.072	0.295	0.304	0.155
STATES REGULATING THE UTILITIES BELOW ARE Ca												
PACIFIC GAS & ELECTRIC	0.240	0.149	0.151	0.147	0.119	0.133	0.120	0.138	0.154	0.098	0.108	0.132
SAN DIEGO GAS & ELECTRIC	0.511	0.162	0.166	0.174	0.142	0.117	0.080	0.072	0.125	0.023	0.213	0.127
SOUTHERN CALIF EDISON CO	0.342	0.136	0.115	0.103	0.108	0.096	0.106	0.113	0.253	0.160	0.183	0.139
STATES REGULATING THE UTILITIES BELOW ARE Co												
PUBLIC SERVICE CO OF COLO	0.365	0.149	0.152	0.157	0.139	0.110	0.108	0.118	0.120	0.219	0.191	0.146
STATES REGULATING THE UTILITIES BELOW ARE Conn												
UNITED ILLUMINATING CO	0.412	0.182	0.154	0.201	0.173	0.104	0.202	0.146	2.526	0.143	0.112	0.394
STATES REGULATING THE UTILITIES BELOW ARE Del												
DELMARVA POWER & LIGHT	0.472	0.201	0.206	0.175	0.111	0.086	0.079	0.112	0.180	0.106	0.089	0.134
STATES REGULATING THE UTILITIES BELOW ARE Fl												
FLORIDA POWER & LIGHT	0.575	0.187	0.203	0.194	0.171	0.155	0.124	0.193	0.222	0.658	0.212	0.236
FLORIDA POWER CORP	0.636	0.189	0.197	0.192	0.169	0.144	0.133	0.155	0.061	0.446	0.434	0.212
TAMPA ELECTRIC CO	0.773	0.210	0.194	0.176	0.149	0.109	0.160	0.178	0.125	0.295	0.229	0.182
STATES REGULATING THE UTILITIES BELOW ARE Ge												
SAVANNAH ELEC & POWER	0.537	0.160	0.181	0.162	0.127	0.075	0.066	0.059	0.140	0.279	0.191	0.144
STATES REGULATING THE UTILITIES BELOW ARE HA												
HAWAIIAN ELECTRIC CO	0.477	0.140	0.156	0.157	0.137	0.128	0.118	0.132	0.136	0.166	0.161	0.143
STATES REGULATING THE UTILITIES BELOW ARE IL												
ILLINOIS POWER CO	0.497	0.270	0.265	0.249	0.223	0.173	0.145	0.168	0.181	0.225	0.197	0.209
COMMONWEALTH EDISON	0.307	0.212	0.203	0.172	0.136	0.106	0.126	0.154	0.162	0.188	0.223	0.163
CENTRAL ILL PUBLIC SERVICE	0.567	0.242	0.243	0.235	0.197	0.171	0.132	0.149	0.179	0.234	0.251	0.203
CENTRAL ILLINOIS LIGHT	0.487	0.174	0.177	0.187	0.191	0.158	0.153	0.163	0.196	0.376	0.231	0.201
STATES REGULATING THE UTILITIES BELOW ARE In												
PUBLIC SERVICE CO OF IND	0.423	0.203	0.214	0.204	0.187	0.152	0.183	0.240	0.320	0.257	0.326	0.233
NORTHERN INDIANA PUBLIC SERV	0.337	0.237	0.230	0.224	0.230	0.188	0.179	0.216	0.223	0.267	0.254	0.225
INDIANAPOLIS POWER & LIGHT	0.694	0.231	0.225	0.210	0.204	0.192	0.209	0.188	0.172	0.329	0.711	0.267
STATES REGULATING THE UTILITIES BELOW ARE Iowa												
IOWA POWER & LIGHT	0.353	0.205	0.195	0.181	0.139	0.159	0.148	0.212	0.187	0.241	0.247	0.191
IOWA SOUTHERN UTILITIES CO	0.571	0.200	0.214	0.243	0.228	0.217	0.218	0.209	0.261	0.204	0.175	0.217
STATES REGULATING THE UTILITIES BELOW ARE KA												
KANSAS POWER & LIGHT	0.281	0.187	0.200	0.204	0.198	0.199	0.194	0.187	0.144	0.174	0.232	0.192
KANSAS GAS & ELECTRIC	0.558	0.210	0.220	0.231	0.199	0.158	0.120	0.123	0.149	0.317	1.111	0.284
STATES REGULATING THE UTILITIES BELOW ARE Ke												
LOUISVILLE GAS & ELECTRIC	0.436	0.247	0.263	0.267	0.240	0.223	0.198	0.217	0.188	0.261	0.333	0.244
STATES REGULATING THE UTILITIES BELOW ARE Me												

CENTRAL MAINE POWER CO	0.310	0.191	0.185	0.172	0.166	0.139	0.174	0.156	0.123	0.155	0.182	0.164
MAINE PUBLIC SERVICE	0.491	0.143	0.133	0.153	0.153	0.123	0.136	0.171	0.195	0.157	0.181	0.155
STATES REGULATING THE UTILITIES BELOW ARE			Mass									
BOSTON EDISON CO	0.525	0.156	0.157	0.133	0.085	0.048	0.018	0.078	0.103	0.131	0.114	0.102
FITCHBURG GAS & ELEC LIGHT	0.387	0.131	0.149	0.125	0.114	0.111	0.119	0.096	0.067	0.111	0.150	0.117
STATES REGULATING THE UTILITIES BELOW ARE			Mich									
EDISON SAULT ELECTRIC	0.0	0.229	0.224	0.192	0.159	0.129	0.136	0.168	0.202	0.127	0.116	0.168
DETROIT EDISON CO	0.714	0.149	0.141	0.142	0.094	0.073	0.078	0.085	0.080	0.079	0.094	0.101
UPPER PENINSULA POWER	0.440	0.165	0.162	0.156	0.121	0.119	0.174	0.172	0.088	0.114	0.185	0.146
CONSUMERS POWER CO	0.711	0.193	0.178	0.158	0.138	0.095	0.087	0.101	0.055	0.149	0.206	0.136
STATES REGULATING THE UTILITIES BELOW ARE			Mn									
MINNESOTA POWER & LIGHT	0.390	0.166	0.190	0.178	0.157	0.148	0.107	0.128	0.157	0.224	0.229	0.168
STATES REGULATING THE UTILITIES BELOW ARE			Mo									
MISSOURI PUBLIC SERVICE CO	0.631	0.184	0.126	0.129	0.192	0.153	0.175	0.142	0.182	0.203	0.226	0.171
ST JOSEPH LIGHT & POWER	0.599	0.168	0.190	0.160	0.184	0.219	0.195	0.170	0.192	0.192	0.199	0.187
STATES REGULATING THE UTILITIES BELOW ARE			Ne									
NEVADA POWER CO	0.650	0.143	0.152	0.146	0.103	0.104	0.129	0.106	0 ~~0.216~~	0 ~~-0.276~~	0.147	0.129 ~~0.377~~
STATES REGULATING THE UTILITIES BELOW ARE			NH									
CONCORD ELECTRIC CO	0.0	0.097	0.136	0.127	0.119	0.120	0.138	0.105	0.137	0.223	0.187	0.139
STATES REGULATING THE UTILITIES BELOW ARE			NJ.									
ATLANTIC CITY ELECTRIC	0.555	0.187	0.188	0.160	0.110	0.078	0.101	0.158	0.217	0.303	0.323	0.182
PUBLIC SERVICE ELEC & GAS	0.639	0.152	0.149	0.130	0.081	0.096	0.049	0.058	0.146	0.182	0.316	0.136
STATES REGULATING THE UTILITIES BELOW ARE			NM									
PUBLIC SERVICE CO OF N MEX	0.592	0.205	0.186	0.181	0.185	0.168	0.171	0.183	0.170	0.274	0.285	0.201
STATES REGULATING THE UTILITIES BELOW ARE			NY									
LONG ISLAND LIGHTING	0.530	0.166	0.162	0.181	0.152	0.143	0.118	0.142	0.202	0.663	-0- ~~50.323~~	0.187 ~~5.225~~
NIAGARA MOHAWK POWER	0.490	0.140	0.095	0.093	0.077	0.085	0.096	0.063	0.111	0.181	0.122	0.107
NEW YORK STATE ELEC & GAS	0.534	0.172	0.149	0.109	0.105	0.087	0.109	0.129	0.154	0.152	0.232	0.140
ORANGE & ROCKLAND UTILITIES	0.637	0.171	0.148	0.122	0.141	0.020	0.048	0.112	0.091	0.155	0.183	0.119
ROCHESTER GAS & ELECTRIC	0.606	0.159	0.122	0.091	0.039	0.104	0.109	0.159	0.092	0.140	0.160	0.122
CENTRAL HUDSON GAS & ELEC	0.480	0.151	0.165	0.146	0.075	0.134	0.139	0.169	0.060	0.161	0.184	0.138
CONSOLIDATED EDISON OF N.Y.	0.802	0.094	0.091	0.077	0.041	0.047	0.036	0.063	0.123	0.143	0.169	0.088
STATES REGULATING THE UTILITIES BELOW ARE			Oh									
CLEVELAND ELECTRIC ILLUM	0.334	0.224	0.225	0.158	0.164	0.154	0.144	0.168	0.486	0.873	~~2.390~~	~~0.5[illegible]~~ 0.293
OHIO EDISON CO	0.432	0.230	0.224	0.218	0.173	0.136	0.129	0.194	0.344	~~21.110~~ 0	~~42.734~~	~~3.320~~ 0.20
COLUMBUS & SOUTHERN OHIO	0.603	0.194	0.161	0.156	0.098	0.069	0.088	0.128	0.047	0.889	0.396	0.225
TOLEDO EDISON COMPANY	0.418	0.237	0.244	0.243	0.210	0.176	0.164	0.319	~~[illegible]~~ 0	~~15.346~~	~~13.002~~	~~[illegible]~~ 0.228
CINCINNATI GAS & ELECTRIC	0.294	0.249	0.245	0.225	0.185	0.157	0.172	0.210	0.132	0.177	0.184	0.201
DAYTON POWER & LIGHT	0.479	0.269	0.218	0.186	0.132	0.135	0.121	0.103	0.118	0.249	0.254	0.178
STATES REGULATING THE UTILITIES BELOW ARE			Ore									
PORTLAND GENERAL ELECTRIC CO	0.444	0.120	0.117	0.135	0.115	0.142	0.116	0.134	-0- ~~[illegible]~~	-0- ~~15.693~~	0.619	0.187 ~~[illegible]~~
STATES REGULATING THE UTILITIES BELOW ARE			Pe									
PENNSYLVANIA POWER & LIGHT	0.441	0.181	0.158	0.130	0.068	0.084	0.120	0.167	0.329	0.356	0.391	0.198
PHILADELPHIA ELECTRIC CO	0.438	0.166	0.146	0.130	0.086	0.095	0.036	0.139	0.303	0.303	0.344	0.180
DUQUESNE LIGHT CO	0.504	0.231	0.222	0.174	0.103	0.139	0.116	0.150	0.276	0.375	0.184	0.197
STATES REGULATING THE UTILITIES BELOW ARE			SC									
SOUTH CAROLINA ELEC & GAS	0.341	0.186	0.197	0.157	0.098	0.078	0.089	0.083	0.124	0.256	0.361	0.163
STATES REGULATING THE UTILITIES BELOW ARE			Tex									
SOUTHWESTERN PUBLIC SERV CO	0.374	0.194	0.209	0.227	0.230	0.226	0.206	0.234	0.306	0.312	0.333	0.248
SOUTHWESTERN ELEC SERVICE	0.371	0.178	0.181	0.207	0.217	0.210	0.209	0.211	0.205	0.204	0.189	0.201
STATES REGULATING THE UTILITIES BELOW ARE			Ve									
GREEN MOUNTAIN POWER CORP	1.063	0.155	0.126	0.095	0.055	-0.045	0.039	0.049	0.142	0.168	0.175	0.096
STATES REGULATING THE UTILITIES BELOW ARE			WA									
PUGET SOUND POWER & LIGHT	0.476	0.090	0.094	0.087	0.080	0.085	0.105	0.107	0.219	0.216	0.176	0.126
STATES REGULATING THE UTILITIES BELOW ARE			WI									
MADISON GAS & ELECTRIC CO	0.367	0.115	0.119	0.131	0.100	0.088	0.070	0.221	0.709	0.300	0.221	0.207
WISCONSIN ELECTRIC POWER	0.140	0.187	0.155	0.155	0.123	0.144	0.197	0.242	0.212	0.213	0.218	0.185
WISCONSIN POWER & LIGHT	0.419	0.223	0.226	0.200	0.199	0.147	0.138	0.236	0.327	0.329	0.340	0.236
OKLAHOMA GAS & ELECTRIC	0.342	0.220	0.219	0.248	0.242	0.226	0.218	0.244	0.251	0.258	0.267	0.239
SIERRA PACIFIC POWER CO	0.502	0.105	0.098	0.100	0.093	0.095	0.114	0.132	0.127	0.119	0.173	0.116
MULTISTATE												
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
UTAH POWER & LIGHT	0.344	0.149	0.141	0.135	0.114	0.106	0.131	0.125	0.105	0.152	0.291	0.145
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
WASHINGTON WATER POWER	0.282	0.135	0.151	0.152	0.138	0.131	0.120	0.137	0.145	0.153	0.185	0.145
UNION ELECTRIC CO	0.400	0.154	0.148	0.138	0.134	0.081	0.059	0.107	0.103	0.257	0.321	0.150
SOUTHERN INDIANA GAS & ELEC	0.445	0.217	0.228	0.218	0.209	0.197	0.199	0.222	0.209	0.210	0.240	0.215
IOWA-ILLINOIS GAS & ELEC	0.734	0.205	0.190	0.162	0.115	0.082	0.180	0.163	0.181	0.196	0.211	0.168
EMPIRE DISTRICT ELECTRIC CO	0.326	0.207	0.215	0.172	0.186	0.169	0.160	0.152	0.149	0.158	0.171	0.174
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
KANSAS CITY POWER & LIGHT	0.481	0.177	0.171	0.165	0.148	0.140	0.121	0.125	0.166	0.198	0.259	0.167
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
GULF STATES UTILITIES CO	0.484	0.207	0.201	0.183	0.159	0.144	0.156	0.181	0.253	0.261	0.283	0.203
PUBLIC SERVICE CO OF N H	0.564	0.147	0.173	0.181	0.146	0.104	0.092	0.094	0.127	0.155	0.184	0.144
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
POTOMAC ELECTRIC POWER	0.460	0.144	0.133	0.095	0.094	0.095	0.127	0.185	0.337	0.168	0.299	0.167
LAKE SUPERIOR DIST POWER CO	0.315	0.149	0.165	0.135	0.123	0.147	0.170	0.181	0.200	0.185	0.147	0.160
WISCONSIN PUBLIC SERVICE	0.291	0.229	0.203	0.174	0.179	0.119	0.145	0.259	0.348	0.325	0.344	0.232
IOWA ELECTRIC LIGHT & PWR	0.713	0.160	0.166	0.164	0.143	0.095	0.106	0.106	-0.025	0.118	0.148	0.118
INTERSTATE POWER CO	0.436	0.190	0.198	0.207	0.184	0.189	0.190	0.203	0.213	0.283	0.538	0.239
PACIFIC POWER & LIGHT	0.487	0.106	0.109	0.108	0.093	0.103	0.107	0.132	0.111	0.135	0.146	0.115
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
NORTHWESTERN PUBLIC SERV CO	0.392	0.174	0.170	0.179	0.189	0.200	0.175	0.240	1.457	0.380	0.206	0.337
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
COMMUNITY PUBLIC SERVICE	0.435	0.158	0.173	0.186	0.194	0.185	0.200	0.192	0.143	0.151	0.186	0.176
EL PASO ELECTRIC CO	0.358	0.228	0.230	0.243	0.226	0.213	0.219	0.219	0.270	0.245	0.225	0.232
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
CENTRAL VERMONT PUB SERV	0.766	0.158	0.111	0.077	0.030	0.018	0.059	-0.008	0.074	0.149	0.161	0.083
~~STATES REGULATING THE UTILITIES BELOW ARE~~			46	33	48							
VIRGINIA ELECTRIC & POWER	0.617	0.189	0.175	0.149	0.108	0.055	0.033	0.086	0.054	0.381	0.515	0.174
OTTER TAIL POWER CO	0.281	0.171	0.151	0.166	0.172	0.206	0.136	0.278	4.234	0.362	0.212	0.614
NORTHERN STATES POWER	0.477	0.182	0.187	0.173	0.147	0.133	0.143	0.133	0.186	0.251	0.263	0.184
IDAHO POWER CO	0.363	0.113	0.147	0.159	0.169	0.178	0.164	0.170	0.152	0.118	0.155	0.152
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
BANGOR HYDRO-ELEC CO	0.524	0.210	0.198	0.165	0.128	0.111	0.169	0.102	0.124	0.190	0.081	0.147
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
BALTIMORE GAS & ELECTRIC	0.423	0.240	0.243	0.223	0.174	0.133	0.095	0.160	1.640	0.492	0.261	0.368
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
DUKE POWER CO	0.612	0.204	0.191	0.146	0.038	0.040	0.017	0.077	0.210	0.246	0.429	0.160
CAROLINA POWER & LIGHT	0.609	0.173	0.187	0.151	0.052	0.076	0.121	0.098	~~[illegible]~~ 0	~~[illegible]~~ 0	0.654	~~[illegible]~~ 0.1[illegible]
IOWA PUBLIC SERVICE CO	0.304	0.199	0.210	0.189	0.154	0.162	0.128	0.144	0.181	0.205	0.206	0.178
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
KENTUCKY UTILITIES CO	0.465	0.203	0.201	0.196	0.155	0.141	0.129	0.182	0.146	0.231	0.214	0.180
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
MONTANA POWER CO	0.311	0.195	0.183	0.218	0.213	0.201	0.191	0.198	0.184	0.164	0.096	0.184
~~STATES REGULATING THE UTILITIES BELOW ARE~~												
BLACK HILLS POWER & LIGHT CO	0.428	0.143	0.143	0.122	0.122	0.171	0.170	0.179	0.225	0.257	0.372	0.190

APPENDIX 6

Ten-Year Returns for Airlines

TABLE NO. 6.1

RATE OF RETURN MEASURE 1

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
~~ALASKA AIRLINES INC~~	~~1.225~~	~~0.015~~	~~0.178~~	~~0.065~~	~~0.185~~	~~0.115~~	~~0.073~~	~~0.071~~	~~0.176~~	~~0.165~~	~~0.179~~	~~0.089~~
ALLEGHENY AIRLINES INC	1.564	0.038	0.008	0.020	0.055	0.036	0.073	0.068	0.068	0.008	0.064	0.044
AMERICAN AIRLINES INC	1.196	0.080	0.056	0.057	-0.002	0.026	0.024	-0.015	0.034	-0.002	0.058	0.032
BRANIFF INTL CORP	1.276	0.050	0.071	0.058	0.026	0.071	0.094	0.112	0.126	0.090	0.099	0.080
~~CAPITOL INTL AIRWAYS~~	~~1.599~~	~~0.262~~	~~0.146~~	~~0.031~~	~~-0.012~~	~~-0.045~~	~~0.063~~	~~0.055~~	~~-0.005~~	~~0.056~~	~~0.132~~	~~0.072~~
CONTINENTAL AIR LINES INC	1.511	0.149	0.045	0.040	0.044	0.057	0.064	0.039	0.078	0.027	0.061	0.060
DELTA AIR LINES INC	0.726	0.281	0.173	0.156	0.149	0.081	0.107	0.156	0.180	0.088	0.102	0.147
EASTERN AIR LINES	1.587	0.068	0.018	0.034	0.046	0.042	0.056	-0.010	0.056	0.003	0.071	0.039
~~FRONTIER AIRLINES INC~~	~~1.177~~	~~0.028~~	~~0.021~~	~~0.072~~	~~[illegible]~~	~~0.012~~	~~0.126~~	~~0.132~~	~~0.171~~	~~0.124~~	~~0.165~~	~~0.067~~
HAWAIIAN AIRLINES INC	0.626	0.017	0.057	-0.006	0.024	0.061	0.095	0.104	0.140	0.010	0.112	0.061
KLM ROYAL DUTCH AIRLINES	0.997	0.075	0.091	0.079	0.056	-0.024	0.007	0.006	0.003	0.020	0.065	0.038
NATIONAL AIRLINES INC	1.415	0.173	0.167	0.132	0.039	0.002	0.094	0.095	0.132	0.054	0.030	0.092
~~NORTH CENTRAL AIRLINES INC~~	~~1.210~~	~~0.060~~	~~0.040~~	~~0.011~~	~~0.085~~	~~0.061~~	~~0.128~~	~~0.117~~	~~0.167~~	~~0.067~~	~~0.100~~	~~0.084~~
NORTHWEST AIRLINES INC	1.113	0.253	0.178	0.122	0.061	0.027	0.027	0.070	0.109	0.056	0.096	0.100
OVERSEAS NATIONAL AIRWAYS	0.328	0.113	0.103	0.035	0.022	0.025	-0.008	-0.073	0.061	0.044	-0.003	0.032
OZARK AIR LINES INC	0.985	0.046	0.033	-0.008	0.022	0.108	0.083	0.037	0.125	0.045	0.129	0.062
~~PSA INC~~	~~1.394~~	~~0.099~~	~~0.073~~	~~-0.077~~	~~0.095~~	~~0.085~~	~~0.081~~	~~0.046~~	~~0.045~~	~~-0.044~~	~~0.076~~	~~0.064~~
PAN AMERICAN WORLD AIRWAYS	1.503	0.106	0.072	-0.001	-0.005	-0.001	0.003	0.013	-0.049	-0.001	0.030	0.017
PIEDMONT AVIATION INC	1.731	0.081	0.032	0.014	0.033	0.056	0.079	0.083	0.119	0.045	0.085	0.063
SEABOARD WORLD AIRLINES	1.469	0.088	0.063	0.029	0.043	0.054	0.090	0.063	0.070	0.019	0.013	0.057
~~SOUTHERN AIRWAYS INC~~	~~[illegible]~~	~~0.001~~	~~0.021~~	~~[illegible]~~	~~-0.043~~	~~0.011~~	~~0.084~~	~~0.070~~	~~0.112~~	~~0.100~~	~~0.046~~	~~0.041~~
~~SOUTHWEST AIRLINES~~	~~[illegible]~~	~~0.000~~	~~0.000~~	~~0.000~~	~~0.000~~	~~[illegible]~~	~~[illegible]~~	~~[illegible]~~	~~0.215~~	~~[illegible]~~	~~0.229~~	~~0.051~~
TIGER INTERNATIONAL	1.050	0.096	0.018	0.076	0.121	0.132	0.114	0.116	0.079	0.080	0.079	0.091
TRANS WORLD AIRLINES	1.597	0.072	0.036	0.039	-0.039	0.029	0.054	0.060	0.021	-0.019	0.066	0.032
~~UAL INC~~	~~0.940~~	~~0.099~~	~~0.069~~	~~0.070~~	~~0.003~~	~~0.024~~	~~0.041~~	~~0.069~~	~~0.113~~	~~0.021~~	~~0.034~~	~~0.054~~
WESTERN AIR LINES INC	1.238	0.126	0.068	-0.035	0.036	0.057	0.081	0.127	0.138	0.033	0.079	0.071
WIEN AIR ALASKA	0.617	0.068	0.028	0.053	0.047	0.044	0.038	0.062	0.183	0.138	0.098	0.076
WORLD AIRWAYS INC	1.428	0.206	0.152	0.092	0.037	0.076	0.043	0.008	0.035	0.066	-0.006	0.071

TABLE NO. 6.2

RATE OF RETURN MEASURE 2

COMPANY NAME	RISK	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	AVERAGE
~~ALASKA AIRLINES INC~~	~~1.225~~	~~0.015~~	~~0.178~~	~~0.065~~	~~0.187~~	~~0.121~~	~~0.074~~	~~0.072~~	~~0.178~~	~~0.166~~	~~0.179~~	~~[illegible]~~
ALLEGHENY AIRLINES INC	1.564	0.038	0.008	0.020	0.055	0.036	0.073	0.068	0.068	0.008	0.064	0.044
AMERICAN AIRLINES INC	1.196	0.080	0.056	0.058	-0.002	0.027	0.024	-0.015	0.034	-0.002	0.058	0.032
BRANIFF INTL CORP	1.276	0.050	0.071	0.058	0.026	0.072	0.095	0.113	0.127	0.090	0.099	0.080
~~CAPITOL INTL AIRWAYS~~	~~1.599~~	~~0.262~~	~~0.146~~	~~0.031~~	~~-0.012~~	~~-0.045~~	~~0.063~~	~~0.055~~	~~-0.005~~	~~0.056~~	~~0.132~~	~~0.072~~
CONTINENTAL AIR LINES INC	1.511	0.149	0.045	0.040	0.045	0.058	0.065	0.039	0.078	0.027	0.062	0.061
DELTA AIR LINES INC	0.726	0.281	0.173	0.157	0.150	0.082	0.108	0.159	0.182	0.088	0.102	0.148
EASTERN AIR LINES	1.587	0.068	0.018	0.034	0.047	0.043	0.057	-0.010	0.056	0.003	0.071	0.039
~~FRONTIER AIRLINES INC~~	~~1.177~~	~~0.028~~	~~0.021~~	~~0.072~~	~~[illegible]~~	~~0.012~~	~~0.126~~	~~0.132~~	~~0.171~~	~~0.124~~	~~0.165~~	~~0.067~~
HAWAIIAN AIRLINES INC	0.626	0.017	0.057	-0.006	0.024	0.061	0.095	0.104	0.140	0.010	0.113	0.062
KLM ROYAL DUTCH AIRLINES	0.997	0.075	0.091	0.079	0.056	-0.024	0.007	0.006	0.003	0.020	0.065	0.038
NATIONAL AIRLINES INC	1.415	0.173	0.167	0.135	0.042	0.003	0.096	0.098	0.136	0.055	0.030	0.093
~~NORTH CENTRAL AIRLINES INC~~	~~1.210~~	~~0.060~~	~~0.040~~	~~0.011~~	~~0.087~~	~~0.061~~	~~0.128~~	~~0.117~~	~~0.167~~	~~0.067~~	~~0.100~~	~~0.084~~
NORTHWEST AIRLINES INC	1.113	0.253	0.178	0.123	0.062	0.027	0.028	0.071	0.110	0.056	0.096	0.100
OVERSEAS NATIONAL AIRWAYS	0.328	0.113	0.103	0.035	0.022	0.025	-0.008	-0.073	0.061	0.044	-0.003	0.032
OZARK AIR LINES INC	0.985	0.046	0.033	-0.008	0.022	0.109	0.083	0.037	0.125	0.045	0.129	0.062
~~PSA INC~~	~~1.394~~	~~0.099~~	~~0.073~~	~~-0.077~~	~~0.095~~	~~0.085~~	~~0.081~~	~~0.046~~	~~0.045~~	~~-0.044~~	~~0.076~~	~~0.064~~
PAN AMERICAN WORLD AIRWAYS	1.503	0.106	0.072	-0.001	-0.006	-0.001	0.003	0.014	-0.049	-0.001	0.030	0.017
PIEDMONT AVIATION INC	1.731	0.081	0.032	0.014	0.033	0.056	0.079	0.083	0.115	0.045	0.085	0.063
SEABOARD WORLD AIRLINES	1.469	0.088	0.063	0.029	0.043	0.094	0.090	0.063	0.070	0.019	0.013	0.057
~~SOUTHERN AIRWAYS INC~~	~~[illegible]~~	~~0.001~~	~~0.021~~	~~[illegible]~~	~~-0.043~~	~~0.011~~	~~0.084~~	~~0.070~~	~~0.112~~	~~0.100~~	~~0.044~~	~~0.041~~
~~SOUTHWEST AIRLINES~~	~~0.000~~	~~0.000~~	~~0.000~~	~~0.000~~	~~0.000~~	~~0.186~~	~~0.068~~	~~0.086~~	~~0.215~~	~~0.235~~	~~0.229~~	~~0.051~~
TIGER INTERNATIONAL	1.050	0.096	0.018	0.076	0.121	0.132	0.114	0.116	0.079	0.080	0.079	0.091
TRANS WORLD AIRLINES	1.597	0.072	0.036	0.039	-0.039	0.030	0.055	0.060	0.021	-0.019	0.066	0.032
~~UAL INC~~	~~0.940~~	~~0.099~~	~~0.069~~	~~0.070~~	~~0.003~~	~~0.024~~	~~0.041~~	~~0.069~~	~~0.113~~	~~0.021~~	~~0.034~~	~~0.054~~
WESTERN AIR LINES INC	1.238	0.126	0.068	-0.035	0.036	0.057	0.082	0.128	0.141	0.034	0.080	0.072
WIEN AIR ALASKA	0.617	0.068	0.028	0.053	0.047	0.045	0.039	0.063	0.185	0.141	0.098	0.077
WORLD AIRWAYS INC	1.428	0.206	0.152	0.092	0.037	0.076	0.043	0.008	0.035	0.066	-0.006	0.071