# THE NEW MEXICO COST OF SERVICE INDEX
# AN EFFORT IN REGULATORY INNOVATION

prepared by

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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.

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## SUMMARY AND CONCLUSIONS

As a result of the crosscurrents afflicting the electric utilities, there has been an effort to institute new regulatory methods. Among these has been the suggestion for wider use of automatic adjustment clauses (AAC). These permit the adjustment of rates to reflect cost changes without an evidentiary hearing. Those in favor of such clauses maintain that the ratepayer benefits through lower financing costs and improved regulatory efficiency. Those opposed claim such clauses provide a disincentive for improved utility efficiency and an incentive to overbuild plant.

Despite these claims and counterclaims, several variations have been proposed over the past several years in an effort to minimize the perceived problems and accent the perceived advantages. These have included proposals in Illinois, Michigan, New Jersey and New Mexico. The Illinois proposal, which was not approved by that Commission, was originally suggested by Dr. John W. Kendrick. This AAC was an effort to provide an incentive to the company to improve total factor productivity (TFP). The latter is output per unit of input, such as capital, labor, materials, etc. The inputs are weighted to provide a balanced input mix.

The Michigan system ties rate adjustments to changes in the consumer price index. It is believed, by its proponents, to put the utility under pressure to keep the rate of cost increases below those experienced in the economy as a whole.

The New Jersey experiment permits cost adjustments for four cost of service components (labor, taxes, depreciation, and "other"). These

are computed in various ways with the total adjustment limited by a maximum allowable rate of return.

The New Mexico cost of service index (COSI) is the longest running and most comprehensive AAC. Thus it is useful to review it in some detail.

The cost of service index clause, as instituted by the New Mexico Public Service Commission in 1975, is a type of comprehensive automatic adjustment clause similar to that proposed by Kendrick, except for the lack of a total productivity adjustment. Instead of attempting to measure total productivity, the COSI method establishes an allowable rate of return band, currently 13½ to 14½ %. As long as the earned rate of return is within the established band, no adjustment is made to rates. If the company's actual rate of return falls below the lower level of the allowable range, rates are adjusted upward to reflect the increased costs and to bring the company's earned rate of return up to the minimum. Similarly, if the company earns more than the maximum level of the established range, a downward adjustment to rates is made. This system presumably provides an incentive for the utility to be efficient since it can keep earnings up to the maximum allowed. Of greater moment, however, may be the weighting of costs to build in regulatory lag. That is, the rate adjustments to achieve the average rate of return are based on a 12 month average of costs. During a period of rising costs this will result in lower costs for ratemaking purposes than would obtain without averaging. As a consequence, the rates set on a quarterly basis will be below the costs that exist at the time. The company would thus be under pressure to reduce costs.

Under COSI, the company is presumably rewarded for its efficient operations by earning an increased rate of return, and the customer benefits through lower utility rates due to the company's increased efficiency. The range of allowable rates of return to stimulate efficiency is seen as compensation for the reduced regulatory lag which results from the regular adjustments to the company's rates. This system has recently been modified by the Commission (December 29, 1978).

In its original 1975 decision, the commission believed the major benefits to be derived from the institution of COSI would be a reduction in the cost of capital with a consequent stabilization of rates, and reduced regulatory costs. In the interim, opponents have stated that the lack of regulatory lag has resulted in reduced utility efficiency and in overbuilding of capacity.

Our review of the overbuilding arguments indicates that there is no evidence that COSI has encouraged overbuilding. The difference in estimates is more the result of methodology and the uncertainty inherent in forecasting. Any excess capacity that may occur in the future is more likely to result from uncertainty as to the future direction of demand for electricity than from COSI.

Insofar as regulatory lag is concerned, it appears that the TFP of PNM declined from 1968/69 to 1975, the year COSI went into effect. It turned upward in the succeeding year, although the TFP index is still substantially below earlier levels. The short time span since COSI was instituted makes it difficult to assess its impact on productivity. The recent improvement may be more the result of newer, more efficient generating units coming on-line, than the institution

of COSI.

Regulatory costs, on the other hand, appear to have increased for both the commission and the company. The latter substantially increased its expenditures for legal and professional consultative services in the 1970-78 period. While part of these increases result from inflation and the extensive construction program, a substantial portion is the result of regulatory requirements.

The commission, likewise, has found it necessary to devote additional substantial staff time to auditing company data despite a reduction in apparent case load. Regulatory savings inherent in the COSI process are speculative and problematic at best.

In regard to the cost of capital to the Company, a review of the information presented in this report shows that while a short-term reduction in the cost of capital to the Company seems to have accrued as a result of the implementation of COSI, the long-term effects are far less certain. Although the operation of COSI reduces the amount of regulatory lag experienced by PNM, it has not resulted in the Company earning, on any consistent basis, its allowed rate of return. Moreover, there is nothing to indicate that any of the financial benefits believed to have resulted from COSI could not also have accrued under the operation of more traditional ratemaking procedures.

COSI does act to reduce the level of uncertainty connected with the amount and timing of rate relief to the Company, and as such, could be expected to have a positive effect on the Company's cost of capital. As it became obvious that COSI did not result in PNM actually earning its allowed rate of return on common equity, whatever positive effect

COSI had had on the cost of capital seems to have dissipated. The ability to earn the allowed rate of return is more important to the financial community than the methods used. The company did receive a financial advantage in the early days of COSI, but this does not appear to be happening now.

Insofar as rates are concerned, an analysis of typical monthly electric bills for PNM and for nine comparison companies indicated that COSI has had no observable impact on the company's service rates as compared with those of the other companies. That is, the reduced regulatory lag and increased pass-through of costs which result from the initiation of COSI have not resulted in higher rates of service for PNM over those of other companies without the benefit of a COSI type mechanism.

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 overbuilding; 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.

# THE NEW MEXICO COST OF SERVICE INDEX - AN EFFORT IN REGULATORY INNOVATION

## INTRODUCTION

The electric utilities have been beset by rising costs, fuel problems, uncertain future demand, difficulties in raising capital, and other assorted ills. The result of these several forces and cross-currents has been a public perception of a regulatory system that is unable to do its job. As a consequence, there has been an effort to institute new regulatory methods. Among these has been the suggestion that automatic adjustment clauses (AAC) be used more widely. An automatic adjustment clause, when costs are rising, permits the pass-through to the ratepayer of costs without an evidentiary hearing. When costs are declining, the AAC permits rates to decline in a relatively rapid fashion.

The proponents of such clauses maintain these result in lower financing costs and improved regulatory efficiency. Opponents dispute these claims, and further assert that AAC's will provide a disincentive to productivity improvement, an incentive to overbuild plant, and a distortion of generating mix.

Despite these claims and counterclaims, there have been efforts in recent years to institute such clauses in various guises. Some are tied to cost indices of various kinds, and some use complex formulae. Of all of these efforts, the longest running and most comprehensive has been the New Mexico cost of service index (COSI). This effort permitted the pass through, on a quarterly basis, of the full cost-

of-service except fuels, without further action by the Commission. Fuels are subject to a separate AAC. Recent Commission action puts COSI on an annual basis.

Inasmuch as this is the first and most complete effort to use a general AAC in the regulatory environment, it appears useful to review its workings, assess the claims and counterclaims, and weigh the potential for adoption elsewhere. To this end we have prepared this report. In doing so, we have attempted to evaluate COSI in regard to the claims made for it, as well as the counterclaims against it. That is, does the application of the COSI concept result in improved regulatory efficiency and lower financing costs, or does it cause poorer productivity and overbuilt plant?

In preparing this document we have reviewed the available literature and pertinent portions of the record in the New Mexico P.S.C. case that treats the COSI concept. In addition, we have discussed COSI with members of the P.S.C. staff, Public Service of New Mexico (PNM) personnel, attorneys for PNM and the New Mexico Attorney General, as well as representatives of several New York financial houses dealing in utility stocks and bonds (see Appendix A for a list of persons interviewed).

## AUTOMATIC ADJUSTMENT CLAUSES - A REVIEW

### A Brief History of AAC's

Automatic adjustment clauses are not a recent phenomenon. The periodic adjustment of incomes and financial asset values to reflect changes in price levels is in widespread use throughout the rest of the

United States economy.[1/] Millions of workers in the U.S. enjoy escalator clauses in their collective bargaining agreements providing for wage increases in line with increases in the consumer price index. Social security recipients, retired military and federal Civil Service employees and survivors, and postal workers also have their incomes tied to changes in the price index. Many construction contracts, rental agreements and long-term purchasing contracts have clauses allowing sales prices to rise in conjunction with increases in the seller's costs.

In the utility industry, the most common AAC's are those dealing with fuel and purchased gas costs. Fuel adjustment clauses in electric utility tariffs originated during World War I at a time of rapidly rising fuel costs and as a result of claims by industry observers that the regulatory process was too slow to deal effectively with the increasing fuel costs.[2/] By the mid-1920's, fuel adjustment clauses were included in the tariffs of many of the Nation's electric utilities, and in the 1930's a number of automatic tax clauses were also adopted. A majority of the privately-owned electric utilities in the U.S. had instituted fuel adjustment clauses by 1958. Most of these clauses, however, were limited to commercial and industrial customers. During the 1960's many utilities were permitted by their regulatory commissions

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1. Kuhn, James Wm., "Indexing:Pro and Con," The Academy of Political Science, New York, N.Y., 1975.

2. Trigg, R.S., "Escalator Clauses in Public Utility Rate Schedules," 106 University of Pennsylvania Law Review, 964 (1958); also Current Issues in Electric Utility Rate Setting, National Association of Regulatory Utility Commissioners, Washington, D.C., April 13, 1976, p. 8-60.

to include fuel adjustment clauses in the tariffs of residential customers as well. A recent publication of the National Association of Regulatory Utility Commissioners reported that FAC's are currently in use in 43 states and the District of Columbia.[3/] For electric utilities, only the Idaho, Montana, Oregon, Utah, Washington and West Virginia commissions do not permit the use of FAC's. Nebraska has no investor owned electric utilities and does not regulate the publicly-owned utilities.

Pros and Cons

Traditionally, a change in the cost of providing service is reflected in a utility's rates only after a full evidentiary hearing (rate case) in which all interested parties present their views and in which the financial and operating information of the company can be thoroughly scrutinized. At the completion of the hearing process, the commission establishes a revenue requirement designed to recover the cost of providing service to the customers plus a fair return on the investment. By allowing changes in costs to be passed on to the ratepayers without the necessity of a rate case, automatic adjustment clauses are said to reduce commission oversight of utility company operations and to reduce the time between a change in cost and the adjustment in rates to reflect this change. In exchange for this

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3. National Association of Regulatory Utility Commissioners, "State Commission Regulation and Monitoring of the Fuel Adjustment Clause, Purchased Gas Adjustment Clause, and Electric and Gas Utility Fuel Procurement Practices," Washington, D.C., October 27, 1978, p. 6.

reduction in regulatory lag, the utility and its customers are perceived by some to benefit from the ability of the company to maintain or improve its financial position by more frequent but smaller rate changes and by reduced risk to the company resulting in a lower cost of capital than would otherwise be the case. The net benefit of these advantages is believed by some to be lower rates than would occur under the traditional system.

In any case, an AAC does not replace regulatory authority. The financial records of the company are still audited to ensure accuracy in calculation of the cost adjustments. The commission would also retain its authority over the financial operations of the company (including the issuance of new debt and common and preferred stock), and the company's expansion plans. Also, the need to review and adjust the company's allowed rate of return on investment would still be required (since the cost of capital would not likely be included in the automatic adjustment mechanism) in addition to periodic reviews of the operation of the comprehensive AAC itself. Finally, rate structure matters would still be of concern to the commission.

Proponents of AAC's state that during periods of rapid inflation, the utility's management is not as able to control costs as they would be during more "normal" times. It is argued that the time required to hold hearings and issue a decision, during periods of rapidly rising prices, will result in inadequate revenues because of continuing cost increases incurred by the utility during the ratemaking process.

Aside from operating problems engendered by inadequate revenues, a utility company must compete in the financial markets for new invest-

ment capital. Indeed, the landmark Supreme Court decisions in the Hope Natural Gas and Bluefield Waterworks cases established that a regulated utility must be given an opportunity to earn a rate of return equal to that of other companies of similar risk so that the utility may compete in the financial markets and attract new investment capital to its operations. If, due to the combination of regulatory lag and inflationary pressure the utility does not earn a rate of return equal to that of similar companies and sufficient to meet its debt commitments, the company will either experience difficulty in obtaining funds, or suffer an increase in its cost of capital due to the perceived risk by investors. Automatic adjustment clauses help ensure the financial integrity of the utility by reducing the lag and maintaining a closer correlation between revenues and costs.

Other largely external factors, such as the unanticipated cost increases due to OPEC cartel pricing policies as well as environmental restrictions, can also make it extremely difficult, if not impossible, for a utility to earn its allowed rate of return. This may be further compounded by the presumed exhaustion of economies of scale that formerly offset rising costs in other areas.

High rates of growth in the demand for electricity are another source of financial risk.[4/] Because of the capital intensity of the industry, high growth rates place a financial burden on individual utilities. Also, since utilities are required to provide adequate

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4. The rate of growth in demand for electrical energy has declined somewhat over the last several years due largely to the substantial increase in price. However, individual utilities are still experiencing substantial growth in demand within their own service territories. This is particularly true for Public Service of New Mexico.

service at all times, they must finance capacity additions even during periods of high capital costs when other, non-regulated companies might postpone their expansion plans. This is further compounded by the fact that future plant will cost more than current plant. A utility financing higher cost plant expansion, but receiving revenues based on historical costs, will find its rate base (the value of plant used and useful in providing service) growing at a faster rate than revenues. As a consequence, assuming no additional economies of scale or increased productivity, the utility will experience a gradual erosion of its rate of return (attrition). A utility experiencing attrition will likely have increased difficulty in attracting new investment capital.

Attrition is often cited as a major reason for using automatic adjustment clauses. Since AAC's allow utility companies a faster pass-through of increased costs to the ratepayers than would otherwise be the case, these are presumed to increase the ability of utilities to earn their allowed rate of return. This is particularly true if a portion of the plant expansion costs are included.

AAC's may also reduce regulatory commission oversight of utility operations since cost changes are passed through to the ratepayer with out the necessity of a rate case. Opponents of automatic adjustment clauses argue that due to the "cost plus" nature of utility regulation, regulatory lag is one of the few tools available to the regulator with which to ensure the efficient operation of the company. It is further argued that the reduction in commission oversight of utility operations which results from the initiation of an AAC reduces the incentive of

company management to maintain or improve efficiency. AAC's are also said to alter the production process in favor of those cost elements which can be more easily passed through to the ratepayer. Fuel adjustment clauses (FAC's), which are the most common form of AAC's, may provide a financial incentive to alter the mix of fuels in favor of those covered by the FAC. Management may also alter the generation mix of facilities by opting to construct generating plants which burn the type of fuels included in the operation of the clause. Thus, plants which are more fuel intensive may be substituted for plants which are more capital intensive (i.e., combustion turbines as opposed to coal fired generation). Also, management may be less inclined to seek out the lowest cost fuel source if these costs can be recovered quickly.

Some have argued that a more comprehensive AAC, covering cost items other than fuels, may eliminate the possible bias of utility management toward over-emphasis of those costs covered by a single item clause (in this case fuel costs).

Some Selected Examples

As a consequence of the various reasons indicated earlier, a number of proposals for comprehensive AAC's have been made before several state regulatory commissions. We have selected a few of these to illustrate various methodological approaches to the application of an automatic adjustment clause. These are briefly discussed below.

Illinois Cost and Efficiency Clause - On March 29, 1974, the Illinois Bell Telephone Co. filed a tariff proposal with the Illinois Commerce Commission. The proposal included a monthly cost and efficiency

revenue adjustment clause (CEAC). This clause, as suggested by Dr. John W. Kendrick, takes into consideration changes in the total factor productivity (TFP) of the company.[5] TFP is output per unit of input computed for each "factor," such as capital, labor, etc. The inputs are weighted to achieve a representative balance. The TFP concept does not indicate economic efficiency per se because of market imperfections such as government regulation. It is, however, a measure of technical efficiency over time.[6]

The application of the TFP concept to utilities through the cost and efficiency clause only permits the company to recover its cost increases if it has maintained its historic level of total factor productivity. The basic formula used in the CEAC proposal is as follows:

CEA = (a X + b Y) or Z, whichever function is less

X = aggregate dollar value of the percentage change in unit costs (plus or minus), exclusive of net income (return to equity) before income taxes.

Y = aggregate dollar cost savings (plus or minus) associated with changes in efficiency.

Z = change in aggregate revenue (plus or minus) required to meet the allowed ceiling rate of return.

a, b = coefficients as specified in the tariff to permit full recovery of unit cost changes if the change in total productivity equals or exceeds the recent trend rate for the company.

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5. Kendrick, John W., "Efficiency Incentives and Cost Factors in Public Utility Automatic Revenue Adjustment Clauses," The Bell Journal of Economics, Spring 1975, p. 299-313.

6. Kendrick, John W., "Productivity Trends in the United States," NBER, Princeton University Press, 1961; "Postwar Productivity Trends in the U.S.," Columbia University Press, 1973.

The operation of the formula is such that a utility company will recover a portion of the increase in unit costs of service (the a X term) automatically through the operation of the clause. The other portion of the increase in unit costs will be recovered only if the company's current rate of productivity increase is at least as much as its trend rate. The "Z" term in the formula ensures that the company will not be able to earn a rate of return above that allowed by the commission in the most recent rate case.

The CEAC type of clause, because of its comprehensive nature, is believed to reduce the possibility of management bias toward a particular factor of production. In addition, the clause also includes a stimulus to management efficiency. This second characteristic is certainly the most appealing since AAC's, by definition, reduce regulatory lag which has traditionally been regarded by many economists as regulation's most important impetus to efficiency. The major difficulties with the Kendrick CEAC are encountered in determining the values for the "a" and "b" coefficients (particularly the "b" coefficient, the value of which depends on the recent trend rate of total productivity for the company and on the projected rate of inflation), and in deriving a measure of total productivity for the utility. 7/

In a discussion of the CEAC concept and public utility productivity, Mr. H. A. Latimer, Vice President and Treasurer of Illinois Bell, notes that the opportunity for a company to earn a higher level of earnings

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7. The Kendrick article cited in footnote 5 describes the process involved in deriving values for the "a" and "b" coefficients and for total productivity.

is the essential stimulus to increasing productivity in a private enterprise society.[8/] Mr. Latimer also notes that regulators have long ago accepted the general requirement that utilities operate efficiently, and have given at least token support to the concept that higher earnings should be allowed where above average productivity performance is evidenced. He says that differences and difficulties in measuring productivity performance, however, along with pressure on regulators to keep utility prices and earnings low, have blunted past regulatory efforts in this area. Mr. Latimer believes these past constraints can be removed, because of advances in computer technology and in the concept and methodology of applied total productivity indexes.

In line with this belief, the monthly, two-way CEAC proposed by Illinois Bell is designed to eliminate the major weaknesses in the AAC concept by providing for timely, balanced cost recovery and an opportunity for increased profits in conjunction with a strong financial incentive for increasing operating efficiency. The incentive is limited by an overriding ceiling on the rate of return.

The CEAC concept is intended to permit the utility to recover increased costs to the extent that the current improvement in the company's productivity at least matches its historical average rate of increase. The concept also includes an authorized range of rates of return. This range must be sufficiently broad to provide the

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8. Latimer, H. A., "The Application of a Productivity Measurement System to Public Utilities," chapter in Public Utility Productivity: Management and Measurement, edited by Walter L. Balls and Jay M. Shafritz, The New York State Department of Public Service, Albany, New York, 1975, p. 177-196.

opportunity of a reward to the company even after numerous advances in productivity have been achieved and rewarded. Mr. Latimer recommends a range of four percentage points on equity capital or two percentage points on overall rate of return.

The Illinois Bell CEAC proposal was rejected by the Illinois commission, after extensive public hearings and testimony, on February 26, 1975.

The Michigan Indexing Method - The Michigan Public Service Commission initiated an automatic rate adjustment clause for Consumers Power Company in conjunction with a $55 million rate increase effective February 1979. The decision and order of the commission allows the company to adjust its rates for increases in operating and maintenance expenses, other than fuel, purchased power and electric production costs, by a percentage amount equal to the increase in the national consumer price index (CPI). The adjustment is to take effect automatically each February, based on the preceding September-to-September rise in the CPI. Company spokesmen stated that operating and maintenance expenses have been increasing at a faster rate than the CPI, rising at a 13.5 percent annual rate in 1977. The automatic rate adjustment clause will allow the company to recover an estimated two-thirds of its increase in costs without the necessity of a rate hearing.

The automatic indexing system consists of a four-step process. First, the commission determines the percentage increase in the CPI for the 12-month September-to-September period. Second, the percentage increase figure is multiplied against the amount of operating and maintenance expense allowed in the most recent rate case. Third, the

calculated adjustment figure is allocated over the total amount of jurisdictional electric sales for the previous 12-month period. Fourth, the average adjustment on a per kilowatt-hour basis is applied to jurisdictional customer's monthly bills.

By making the automatic revenue adjustment contingent on retail cost changes in the economy rather than on utility-incurred costs, the commission staff believes that company management becomes subjected to outside cost pressures. If the utility company performs as well as the economy as a whole, as reflected in the CPI, it will recover its increased costs through the indexing system; if the company outperforms the CPI, it will be rewarded with increased earnings; and if management is lax, permitting costs to rise faster than the CPI, stockholders will suffer a reduction in earnings. The staff believes the company, through the operation of this AAC, has an incentive to be efficient. It will be automatically rewarded for efficiency and punished for inefficiency. The commission has also recommended an identical indexing system for Detroit Edison Company.

The New Jersey Comprehensive Adjustment Clause - On December 13, 1973, the New Jersey Public Utilities Commission approved a comprehensive adjustment clause for New Jersey Bell Telephone Company.[9/] The clause, as established by the commission's order, permits automatic annual adjustments to the company's rate schedules based on changes in the

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9. New Jersey Board of Public Utility Commissioners, "Re: Adjustment Clause in Telephone Rate Schedules," Docket No. 732-134, December 13, 1973. Reprinted in Public Utilities Reports, 4th Series, Volume 3, 1974, p. 298-308.

costs of four components of the company's cost of service. These cost components include wages and salaries, taxes (except federal income taxes), depreciation, and "other expenses." The annual adjustment to the company's rates is subject to a maximum allowable rate of return limitation, which is that rate of return established by the commission in the company's most recent rate case.

The adjustment for wages and salaries is computed as the difference between the percentage increase in the average hourly labor compensation for the company and the average rate of increase in output per man-hour in telephone communications for the latest five-year period as reported by the U.S. Department of Labor. The adjustment for taxes is based on changes in the effective rates applicable to the most recent 12-month real estate, revenue and social security taxes. The depreciation adjustment is limited to the actual increase in depreciation between the base-period and the time of review or 12.2 percent of test-year intrastate operating revenues, whichever is smaller. The adjustment for "other expenses" is limited to the percentage increase in the industrial wholesale price index or the actual increase in "other expenses," whichever is smaller.

The commission order establishing the adjustment clause was appealed to the New Jersey Supreme Court on May 14, 1974. The court upheld the commission's action on the basis that the adjustments occasioned through the operation of the comprehensive adjustment clause would be subject to the eventual scrutiny of the commission in a final rate proceeding.

## THE NEW MEXICO COST OF SERVICE INDEX

### COSI

On April 22, 1975, the New Mexico Public Service Commission (PSC) established a cost of service index adjustment clause (COSI) for the Public Service Company of New Mexico (PNM). In the immediately preceding case (1130) instituted on December 20, 1973, the Company had sought an overall rate increase of approximately 15 percent. The PSC, on October 10, 1974, allowed an average increase of approximately 6.6 percent. This rate increase was designed to result in a 14 percent annual rate of return on PNM's jurisdictional common equity capital. The Company appealed the PSC decision to the Santa Fe County District Court.

Case No. 1196 was instituted on January 31, 1975. In that proceeding, PNM through prior stipulation with the PSC and other parties, consented to a reduction in certain of its tariffs and requested approval of a quarterly automatic adjustment in its rates. The rate adjustment is to maintain a 13½ to 14½ rate of return on common equity capital. The Commission stated that it viewed the new regulatory method as an innovation applicable only to PNM and had no intention of implementing the indexing method for other utilities within its jurisdiction.

In discussing its rationale, the Commission noted that the Company is protected from competition in the sale of services to its customers but must still compete with other enterprises in the acquisition of capital, labor, etc. The prices of these inputs are predominately determined by competitive market forces over which the PSC and PNM have little control. During more stable economic, social and political

circumstances, the Commission explained, there was reasonable certainty that rates based on recent test-period costs, would adequately cover the cost of service and allow the utility to satisfy growing demand as well as provide an adequate quality of service. Any moderate post-test period increase in costs experienced by the Company was likely to be at least partially offset by increased operating efficiencies or economies of scale. Rapid inflation, growth in demand, and a consequent increase in capital requirements result in a disparity between costs and rates so that the Company is no longer assured of being able to meet its service obligations for the long-term or even the moderately short-term future.

During 1974, the Commission noted, PNM earned 10.1 percent on average jurisdictional common equity while the allowed return established in Case No. 1130 was 14 percent. In addition, PNM's stock price was only two-thirds of book value at the time of Case 1196. The company was also facing a 5-year construction budget of $742 million, approximately two and one-half times the undepreciated, original cost of its current plant. In order to finance this budget, PNM must be allowed an opportunity to earn a rate of return commensurate with that available to other investors. A modest margin of market value per share above book value for PNM common stock was viewed by the Commission as necessary for the Company to attract investment capital. A market-to-book value ratio of 1.25 was termed as attainable and appropriate.

The decline in the Company's and the utility industry's financial position and the resultant increase in the cost of capital, the Commission stated, are the result of rapid inflation and unprecedented new

capital requirements of the industry. Another significant factor contributing to this unfavorable financial evaluation of the industry is the manner in which rates have traditionally been established by regulatory commissions. The argument is made that under traditional ratemaking procedures, utility companies are not able to earn their allowed rates of return causing investors to respond by discounting the market price of utility common equity below book value. Additionally, as common equity earnings of public utilities decline and become less reliable, risk to the investor increases and thus the cost of new investment capital also increases. Since the cost of capital to utilities must be covered by established rates, regulatory commissions are forced to pass this increased cost on through to the ratepayer in the form of higher utility rates. A principal justification, then, of cost of service indexing is the reduction of the cost of capital to the utility, and ultimately to the ratepayer, through restoration of earnings stability and reliability. Finally, by freeing the Company and the Commission from the burden of traditional, adversary rate proceedings, COSI was presumed to allow Company management and Commission staff more time for other regulatory responsibilities.

Methodology

Under COSI rate changes are triggered by the rate of return. If PNM earns less than the minimum allowed during a quarter, rates are adjusted upward.

If the return on equity is above the upper limit of the specified range, rates are adjusted downward by an amount necessary to restore the Company's return on equity for the accounting period ending with

the next quarter to the upper limit of the specified range. The same incremental adjustment (upward or downward) on a per Kwh basis is to be applied to the energy charge for each class of service.

The range of allowed rates of return on jurisdictional common equity was established at 13.5 to 14.5 percent. The midpoint of the range, 14.0 percent, is the same rate of return established for PNM in its previous rate proceeding. The midpoint of the range cannot be changed except through a traditional rate proceeding.

In order to avoid wide swings in rates as a result of COSI, and to build in regulatory lag to encourage efficiency, the PSC established a 12-month period ending with each calendar quarter as the accounting period upon which the quarterly adjustments are to be based. In addition, operating revenues are to be computed as if the preceding quarterly cost of service adjustment had been in effect for the entire 12-month accounting period.

COSI adjustments are effective one month following the end of the preceding calendar quarter. The Company is to file its COSI Report Form with the Commission not less than ten days before any proposed cost of service adjustment is to take effect.

The system outlined above was modified in a subsequent proceeding (Case 1419).[10/] On December 29, 1978, the Commission ordered the elimination of the quarterly adjustment and institution of an annual adjustment, and the tightening of procedures for monitoring and eval-

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10. New Mexico Public Service Commission, "Decision and Order, Case 1419," December 29, 1978, p. 63-74.

uating COSI, the pass through to the ratepayer of interest income, and the computation of expense and investment allocation factors on a semi-annual rather than annual basis. A further review was ordered in two years. The PSC stated once again that it viewed COSI as an experiment and did not intend to extend it to other utilities until it felt the deficiencies were corrected.

The PSC decision was based on its finding that the company reduced its equity capital costs between 0.84% and 2% per year as a result of COSI, and was able to maintain its "AA" bond rating and "A" preferred stock rating. The commission further declared that COSI did not provide an adequate incentive to resist cost increases and effect economies, and has had a negative impact on regulatory oversight. The latter was ascribed to the limited and insufficient commission staff resources, as well as inadequate procedural and reporting rules.

Impact on Rates

The New Mexico cost of service indexing method operates through the application of a surcharge on the per Kwh energy charge. Since these quarterly rate adjustments are occasioned through COSI without the necessity of a full rate proceeding, there is some concern over the level of rates charged to customers through the operation of an automatic adjustment mechanism as opposed to traditional ratemaking methods. Proponents of automatic adjustment clauses contend that this type of mechanism allows utilities more frequent but smaller individual rate increases than would be the case with traditional ratemaking procedures. The long-term result, however, is rates equal to, or less than, those established by traditional regulatory procedures.

This outcome is the result of efficiency incentives built into the automatic adjustment mechanism and the reduced cost of capital believed to result from its application. Opponents of AAC's contend that the automatic adjustment mechanism deters management efficiency thereby resulting in higher customer charges than would be the case with traditional ratemaking procedures.

In order to determine the effect of COSI on PNM's service rates as compared to established ratemaking practices, a comparison was made between PNM's rates for residential and commercial service and the rates of nine similar electric utilities. The nine were selected on the basis of several financial and operational criteria as reported by Salomon Brothers Stock Research Department. The variables are shown in Table 1 for the selected companies and PNM.

For the purpose of comparison of service rates, AFUDC (allowance for funds used during construction) as a percent of net earnings (an indication of the size of a firm's construction budget) as listed in Column (4), and electric generating fuel mix as listed in Column (9) were considered as being most germane to the analysis. The average value of AFUDC as a percent of net earnings for the nine companies is 47 percent, compared with 42 percent for PNM. This would indicate that the group of 9 and PNM both have construction budgets of similar relative size. This in turn would tend to indicate both have relatively high demand growth rates. None of the 10 companies has a significant quantity of hydro generation.

Also presented are data on rates from the Federal Power Commission's "Typical Electric Utility Bills" (Table 2). The FPC data are for resi-

dential service in all communities with population of 2,500 or more, and commercial service in communities with population of 50,000 or more. Due to this restriction, no information on commercial service is presented for Central Illinois Public Service Company. Thus, the commercial data are eight-company averages. The bills are calculated under the rate schedules generally applicable to the majority of customers taking service under the conditions and classes of service specified, although the utilities may have other rate schedules available that produce different bills from those shown. In each case, the bill data taken from the FPC reports, and shown in Table 2, are for residential and commercial service supplied by the nine comparison companies and PNM for customers in the largest city within each service territory. Industrial customers are not included in this comparison because of the individual nature of such service, and because many such customers provide a part of the required facilities, making it difficult to assess typical bills on the same basis.

In comparing the typical bill, PNM's is generally below those of the other utility companies. The percentage change in PNM's typical electric bills compares favorably with those of the other companies for the 1974-77 period. The major factor is the percentage change in the typical bills for PNM and for the comparison companies. If the COSI methodology acted to discourage efficiency, one would expect a greater percentage increase in PNM's typical electric bills than in the bills of the nine comparison companies, everything else being equal. Of course everything else is not equal, and such factors as customer density, age and size of generating facilities, and system load factor

Table 1

SELECTED FINANCIAL AND OPERATIONAL VARIABLES FOR THE 12-MONTH PERIOD ENDING 9/30/78[a]

| Company | Moody's Bond Rating | Pre-tax Interest Coverage[b] | Capitalization Ratios[c] | AFUDC as a % of Net Earnings | % Return on Common Equity | % Dividend Payout | % Market to Book Value | Regulatory Comm. Ranking | Electric Generating Fuel Mix 12/31/78[d] Nuclear/Coal/Oil/Gas/Hydro |
|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
| Central Ill. Pub. Serv. | Aa | 3.1/2.8 | 50/14/36 | 29% | 11.2 | 79% | 90% | C+ | 0/97/3/0/0 |
| Cleveland Elec. Illum. | Aa | 2.8/2.2 | 49/15/36 | 58 | 12.1 | 81 | 89 | C | 16/81/3/0/0 |
| Illinois Power | Aa | 3.5/3.0 | 51/14/35 | 41 | 13.0 | 83 | 103 | C+ | 0/92/8/0/0 |
| Indianapolis Power and Light | Aa | 3.0/2.8 | 52/12/36 | 24 | 9.6 | 96 | 102 | A | 0/99/1/0/0 |
| Iowa Power and Light | Aa | 3.7/3.0 | 47/13/40 | 42 | 14.6 | 66 | 98 | C- | 47/51/2/0/0 |
| Iowa Public Service | Aa | 3.0/2.4 | 50/15/35 | 53 | 14.5 | 62 | 92 | C- | 0/96/3/1/0 |
| Kansas Power and Light | Aa | 3.4/2.3 | 48/12/40 | 79 | 12.3 | 67 | 83 | C+ | 0/58/21/21/0 |
| Northern Indiana Public Service | Aa | 2.9/2.5 | 51/15/34 | 49 | 9.1 | 88 | 83 | A | 0/98/1/1/0 |
| Public Service of Indiana | Aa | 3.6/3.0 | 47/14/39 | 50 | 12.6 | 76 | 109 | A | 0/98/0/0/2 |
| Average | | 3.2/2.7 | 49/14/37 | 47 | 12.1 | 77.5 | 94 | | |
| Public Service of New Mexico | Aa | 3.6/3.0 | 51/15/34 | 42 | 15.3 | 53 | 88 | B | 0/24/1/75/0 |

NOTES:

a. Source: Salomon Brothers, Stock Research Dated October 12, 1978 and January 3, 1979 and Electric Utility Coverages: Third Quarter 1978, Dated December 18, 1978.

b. The first set of numbers include AFUDC; the second set of numbers are without AFUDC.

c. Long Term debt/Preferred/Common

d. Nuclear/Coal/Oil/Gas/Hydro

Table 2

TYPICAL ELECTRIC BILLS, SELECTED UTILITIES, a/
RESIDENTIAL AND COMMERCIAL SERVICE, JANUARY 1977

| Service | PNM | | Aver. of Nine Utilities | |
|---|---|---|---|---|
| | Jan. 1,1977 | % Change 1974-77 | Jan.1, 1977 | % Change 1974-77 |
| Residential Service | | | | |
| 250 Kwh/month | $10.61 | 34.0% | $12.25 | 40.2% |
| 500 | 18.82 | 78.4 | 20.18 | 56.6 |
| 750 | 26.53 | 77.2 | 28.63 | 60.5 |
| 1000 | 33.49 | 65.1 | 37.49 | 61.7 |
| Commercial Service | | | | |
| 6 Kw/750 Kwh | 37.38 | 29.3 | 42.54 | 33.4 |
| 12 Kw/1500 Kwh | 71.75 | 38.9 | 82.17 | 38.9 |
| 30 Kw/6000 Kwh | 226.02 | 43.1 | 280.49 | 46.8 |
| 40 Kw/10,000 Kwh | 357.36 | 38.4 | 428.76 | 50.0 |

a. Source: Federal Power Commission, "Typical Electric Bills," 1974 to 1977 editions, various tables.

are not directly taken into account in this analysis. A general comparison of PNM's typical bills with those of the nine utilities, however, indicates no significant difference.

Sensitivity of COSI to Time

As previously stated, COSI has regulatory lag built into the methodology. This lag is made up of two factors. First, jurisdictional common equity, upon which the Company's earned rate of return is computed, is derived by computing the average jurisdictional common equity for the preceding 12-month period. Due in large measure to its large construction program, PNM's jurisdictional common equity (a source of financing for this program) is increasing over time. By basing the quarterly adjustment factor on the 12-month average level of common equity, rather than on a semi-annual or quarterly average, PNM's revenue requirement is reduced. The impact of a shift to a shorter time period is shown in Table 3. A 12-month and a 6-month average were used. The latter was selected because one of the modifications to the current COSI mechanism requested by the Company was use of the latest six months average investment rather than the latest twelve months.

If the 6-month average were used the Company's revenue requirement for the quarterly adjustment for September 30, 1977 would increase 13.1 percent. Similarly, the COSI factor would increase from 0.1955 cents/Kwh to 0.2212 cents/Kwh. The amount of increase in revenue requirement and cost of service index factor for other quarterly adjustments would depend on the amount and the timing of additional sales of common equity stock. Increases similar to those shown for the September 30, 1977

Table 3

PUBLIC SERVICE COMPANY OF NEW MEXICO, REVENUE REQUIREMENT AND COST OF SERVICE INDEX FACTOR, SEPT. 30, 1977, BASED ON 12-MONTH AND 6-MONTH AVERAGE COMMON EQUITY[a]

| | 12-months ending Sept. 30, 1977 | 6-months ending Sept. 30, 1977 |
|---|---|---|
| Average Jurisdictional Common Equity | $138,026,388 | $140,899,418 |
| Jurisdictional Net Income Available for Common Equity | $ 15,675,037 | 15,675,037 |
| Return on Average Jurisdictional Common Equity | 11.357% | 11.125% |
| Differential Between Current Return on Equity and Specified Range of Allowed Rates of Return | 2.143% | 2.375% |
| Revenue Differential | $ 6,081,220 | $ 6,879,853 |
| Jurisdictional Kwh Sales | 3,110,448,636 | 3,110,448,636 |
| Cost of Service Index Factor | $0.001955/Kwh | $0.002212/Kwh |

a. Source: Public Service Company of New Mexico, Cost of Service Index Report, Dated September 30, 1977.

quarterly adjustment would be experienced if a 6-month rather than a 12-month average common equity investment were used in the COSI mechanism.

The second component of regulatory lag built into the COSI mechanism is the adjustment to "jurisdictional net income available for common equity" to account for the earlier computed adjustment factors. That is, when the cost of service index factor for September 30, 1977 is computed, it is assumed that the previous quarter's index factor has been in effect for an entire 12-month period, rather than for only 3 months. PNM's jurisdictional net income is then adjusted to represent what it would have been had the previous quarterly adjustment been in effect for a full year. This adjustment tends to overstate income when the company is actually earning less than the minimum rate of return. This assumption results in an adjustment to PNM's jurisdictional electric operating income, and thus a reduction in its revenue requirement. In September 30, 1977, the adjustment amounted to $4,528,436.[11/]

Analysis of COSI

The efficacy of the COSI concept is dependent on an analysis of the major contentions, both pro and con. It is maintained by some that COSI will free the regulatory staff and company personnel for "more important matters," such as plant siting, financing, etc. Others maintain that COSI, because of the easy cost pass through, will

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11. Cost of Service Index Report, September 30, 1977, Public Service Co. of New Mexico, Electric Department, Line 54.

encourage overbuilding of plant.

Aside from these relatively minor issues, two major issues are raised. One deals with the impact of regulatory lag on company efficiency, and the other on financial savings accruing from COSI.

In the material that follows, we shall attempt to dissect these issues.

Improved Regulatory Efficiency - The question of improved regulatory efficiency is difficult to answer because only one company in New Mexico is permitted to use the cost of service index. It may be useful, however, to review the positions expressed by those in the PNM case, and then deal with the Commission's caseload.

In its order establishing COSI (Case 1196) the Commission noted that it had no time to investigate and reflect on management efficiency, demand growth and the justification for new plant certification, rate structure, financing costs, etc. The Commission then stated if it adhered to traditional rate fixing methods it risked losing control of even that function as a result of inflation. It thus anticipated the dawning of a new regulatory day as a consequence of COSI.

The company, in various discussions and in the present case (1419), indicated it felt COSI would free management from the tyranny of the rate case cycle, but Rodney E. Stevenson on behalf of staff noted that the burden of a rate case falls on the rate department rather than the various managerial and operational groups.[12/] Staff stated the tradi-

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12. Testimony of Rodney E. Stevenson, Case 1419, NMPSC, 1978.

tional rate case has three components (cost of capital, revenue requirement, and rate design), of which only the revenue requirement is replaced by COSI. As a consequence, both the company and commission would be required to continue to put a substantial effort into the other phases. It was further estimated by staff that verification of the COSI data requires two to four times the effort required for a similar function in a traditional rate case.[13]

The intervenors make the point that COSI improperly shifts the burden of proof from the company to the commission or the intervenors.[14] The latter are required to constantly review company decisions to assure that new conditions are under control, and to press for hearings as necessary. Over the past few years such investigations have dealt with the Learjet, the San Juan #2 explosion and tax normalization.

The lack of regulatory savings on the company's part is borne out by the substantial increase in its expenditures for legal services (from $43.5 thousand (K) in 1975 to $238 K in 1977) and outside professional-consultative services (from $244 K in 1970 to $6.7 million (m) in 1975, remaining at that level to date).[15] Part of these increases are undoubtedly the result of general inflation, with a further portion accruing as a result of the extensive construction program. In any case, it would be our opinion that company regulatory activity, as indicated by its expenditures for legal and consultative services,

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13. Testimony of Robert L. Swartout, Case 1419, NMPSC, 1978.

14. Conversation with intervenors.

15. Testimony of Jatinder Kumar, Case 1419, NMPSC, 1978.

has substantially increased since the advent of COSI.

Nor does the commission appear to have experienced substantial savings, although it has been spared any PNM rate case in the 1975-78 period. Rate cases rose from 15 in 1975-76 to 28 in 1976-77 and then decreased to 24 in 1977-78. Total cases rose from 71 in 1975-76 to 84 in 1977-78.[16] If all New Mexico companies had been using COSI, thus eliminating rate cases in the 1975-78 period, the implication is that the case load would have only risen by 7% rather than the 18% actually experienced. Despite the drop in caseload, staff time would have increased significantly (possibly by 200%) because of the need to audit the company data and the extra time required to do so. Further, at some point, the commission would have found it necessary to undertake an examination of the rate of return and rate structure issues for each company. This examination would place a further burden on the staff.

Aside from the above, there is apparently an increased need for vigilance on the part of the staff and intervenors. This increase, coupled to higher expenditures for regulatory matters by the company pre- and post-COSI, as well as higher costs for the P.S.C., indicates that regulatory savings inherent in the COSI process are speculative and problematic at best. Given, however, that the commission has dealt with three PNM plant certification and three special cases in the 1975-78 period, it appears that COSI does permit staff to put effort into other things. On the other hand, the subject matter of

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16. Three Year Organizational and Budget Development Plan, NMPSC.

the three special cases would probably have been handled within the context of a traditional rate case and thus would have been unnecessary. We thus conclude there has been no regulatory savings.

Overbuilding - In some of the testimony in the PNM case, it was noted that the company might build capacity not really needed in the future.[17] This would occur because the company would be relieved of capital market constraints due to COSI, compounded by the lack of regulatory constraint regarding construction plans. The latter is not, however, a valid argument since Commission certification is required for each plant. Further, the capital markets would impose their own constraint on borrowing if construction appeared greater than estimated future revenues would warrant. Under present circumstances, money might be available but at a price depending on the perceived risk.

Myron J. Gordon noted that COSI could encourage overbuilding by reducing regulatory lag and making the timing and amount of rate increases more certain.[18] As a consequence, COSI assures that funds will be available to finance growth. This assurance, together with CWIP and AFUDC, encourages the company to overbuild. He further noted that the major demand growth area is the industrial sector with the retail sector expected to decline as a percent of the total. As a consequence, the current ratepayer (largely residential) is forced, through the combination of COSI and CWIP in the rate base, to pay for

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17. Testimony of Robert H. Smiley, Case 1419, NMPSC, 1978.

18. Testimony of Myron J. Gordon, Case 1419, NMPSC, 1978.

future growth. This growth is in large measure industrial, and is highly uncertain since the uranium industry is the major growth sector. In short, Gordon raises the possibility that COSI has forced the present residential customer to pay for problematic growth to serve future industrial loads. Given the current moribund status and problematic future of the nuclear industry, this may well be correct. Such a situation, however, is more an accidental impact than a deliberate incentive to subsidization.

Aside from the above, there is considerable uncertainty as to future utility demand. The industry, in general, stands at an inflection point on the demand curve, and New Mexico is no exception. The uncertainty is highlighted by a disagreement between PNM on one hand and the staff consultants on the other. The disparity is indicated in Table 4.

PNM projects sales growth to 1988 at 7.7% per year compared with its historic rate of 9.4%. The company expects to sell 10.3 billion (B) Kwh in 1988 compared with 4.8 B in 1978. The major growth area is the mining sector, with both coal and uranium expected to exhibit substantial increases.[19/] If uranium mining were to slow down, future electric growth would also decline. The company's estimate is based, in large measure, on the expansion plans of the uranium mining industry. If these do not materialize neither will the load requirements. In any case, the company contends the load growth issue is not significant because it is better to have too much capacity than not enough. PNM estimated outage costs at 50¢/Kwh, considerably more than the estimated

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19. Testimony of Keith B. Van Ausdal, Case 1419, NMPSC.

cost of excess capacity. The company expects that any surplus capacity could be sold, mainly to Southern California.[20]

The staff consultants, on the other hand, estimate an annual growth rate of 5.6%, resulting in sales of 8 B Kwh in 1988, some 29% less than the PNM projection.[21] The difference in estimates is largely because of reduced expectations for mining, although staff anticipates lower growth in virtually all areas; the most notable exception is in expectations for the city of Gallup with staff predicting a 6.7% annual growth rate and PNM 4.6%.

We estimate the difference in capacity between the two estimates at 309 Mw, assuming an 85% capacity factor. The cost differential would be approximately $300 m in construction costs. The company and staff, both anticipate capacity increases ranging from a doubling to 150% of current levels. The two estimates vary by approximately half of current capacity.

The difference in these estimates is more the result of methodology and the uncertainty inherent in forecasting than as a consequence of COSI. That is, the company forecast is based in large measure on industry expectations that may or may not materialize, coupled to econometric models. Staff has largely used econometric models. Of course, we will not know if there has been overbuilding until we get there. In any case, there is no evidence that COSI has encouraged overbuilding. It would be our contention that any excess capacity that occurs in the

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20. Conversation with A. J. Robison, Vice President, PNM.

21. Testimony of Robert Halvorsen, Case 1419, NMPSC.

Table 4

COMPARISON OF ANNUAL SALES GROWTH RATES BY CUSTOMER CLASS, 1978-88 a/
PNM AND COMMISSION STAFF

| Customer Class | Growth Rate | |
|---|---|---|
| | PNM | Staff |
| Residential | 6.4% | 3.1% |
| Commercial | 7.0% | 4.1% |
| Industrial | 14.5% | 11.7% |
| Base and USAF | 6.4% | 4.1% |
| Mining | 21.9% | 17.6% |
| OPA | 3.9% | 4.4% |
| S & H Lighting | 3.2% | 2.5% |
| Interdepartmental | 0.7% | 0.7% |
| Gallup | 4.6% | 6.7% |
| Total Base Sales | 8.9% | 6.2% |
| Resales | 5.9% | 3.9% |
| Total Sales | 7.7% | 5.6% |

a. Source: Testimony of Robert Halvorsen, NMPSC Case 1419, Exhibit RH6 and Testimony of Keith B. Van Ausdal.

future is more the result of unsettled conditions than COSI.

Regulatory Lag - Economic theory tells us that the unregulated firm has the incentive to be efficient because it has the opportunity to keep the advantages of that efficiency for the benefit of the company and its stockholders. This incentive is reinforced under competition by the need for continual cost reductions in order to ensure survival. The regulated firm, on the other hand, lacks the spur of competition to remain efficient, and only has a financial incentive to reduce costs during periods of regulatory lag.

Regulatory lag is the time between the completion of a rate case and the resolution of the next case. It can be broken down into 2 parts, the lag between the filing of a request for a rate increase and its resolution, and the lag between cases.[22/] The latter is important when costs are declining because the utility can keep any earnings above the allowable rate of return, and thus has an incentive to reduce costs further. When costs are rising, rate cases will be filed so close together that this form of lag may be virtually eliminated. The lag during the resolution of a case is important during a period of rising costs. The utility will be earning less than the allowable rate of return, and will be under pressure to become more efficient in order to maintain its position. COSI is believed by some to reduce this incentive to force cost savings by minimizing regulatory lag and

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22. Stevenson, Rodney, E., "Regulating for Efficiency in the Public Utility Industry," Chapter in Public Utility Productivity, cited earlier, p. 197-218.

thus shifting the inflation burden to the ratepayer. Others have suggested that the lag should be reduced in order to increase the utility cash flow and reduce financing costs. These people would maintain that such a reduction would not result in reduced efficiency. Thus a central point of contention is the effect of lag on efficiency.

Determining whether reduced lag helps or hinders efficiency is somewhat difficult. Normally, the level of profit would be used as a measure of efficiency. This does not apply to regulated companies, however, because of the monopolistic nature of their business and the control of profits by the regulatory body. Several alternatives have been proposed including management audits, performance analysis and measurement of total productivity.

PNM ordered a management audit that indicated management is efficient but that some improvement is possible. Annual benefits were estimated in a range of $5.9 million to $7.4 million, primarily through work force productivity and cash management. The company identified 53% of the savings, and the consultant the remainder.[23] Although such studies may indicate weak spots in the company armor, these generally do not provide a measure of efficiency. Audits indicate where improvements can be made, rather than how well the company is utilizing its available resources.

Performance analysis, on the other hand, measures the company's performance against that of comparable organizations. For example, in the New Mexico COSI case (1419) such an analysis was introduced on

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23. Testimony of John T. Ackerman, Case 1419, NMPSC, p. 3.

behalf of the Attorney General by J. Kumar.[24] The analysis was based on data from the FPC performance profiles, and a NARUC performance study.

Kumar stated that PNM's average performance was better in regard to fuel cost and distribution plant, but worse in terms of fixed cost per Kw of annual peak, and comparable for the remaining criteria, based on the FPC performance profiles for 1963-70. If the NARUC performance study were used, PNM would rank among the best group for fuel costs, annual wage rates, capacity utilization and production expenses. The company was average in operating expenses and below average for net utility plant investment, heat rate and labor productivity. Table 5 summarizes the two studies as presented by Kumar. The age of the data used for these comparisons make the results irrelevant for our purposes.

He also made his own analysis. In this study he compared PNM against what he considered to be 27 similar companies. Kumar concluded that PNM ranked among the poorest performers since the advent of COSI, and stated that the continuation of COSI based on improved productivity could not be supported.

The use of performance analysis as a measure of efficiency is somewhat flawed by the need to select comparable companies. Due to technical differences, variations in service areas and in the quality of services provided, such comparisons may not be entirely meaningful. As a consequence, the measurement of productivity as an indicator of how efficiently a company is using its resources, has become increasingly

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24. Testimony of Jatinder Kumar, Case 1419, NMPSC.

Table 5

SUMMARY OF INTER-COMPANY COMPARISON OF PERFORMANCE[a/]

| Variable | Performance Per FPC | Performance Per NARUC |
|---|---|---|
| Total Operating Expense per Kwh sold | - | Poor |
| Production expense per Kwh generated | - | Good |
| Fuel cost per million BTU | Good | - |
| % Gross Plant to Gross Revenue | Average | - |
| Net Utility Investment Per Kwh sold | Poor | Poor |
| Annual Wage Rates per Employee | - | Good |
| Annual Kwh sold per Employee | - | Good |
| Revenue per retail customer | Good | - |

a. Source: Testimony of Jatinder Kumar, NMPSC Case 1419, Schedule 8.

popular.

In an industrialized society, the production of goods and services is dependent on the use of labor, capital, energy and materials. The volume of output is dependent on the quantity of these resources used and on the efficiency with which these are employed. At a given level of technology, different input combinations result in a given output. As a general rule, the least cost combination will be selected, although market imperfections can cause distortions. As prices and technology change, as shortages and political events occur, and as the output fluctuates, the input mix will also change. Partial productivity measures, such as labor productivity, measure these changes to a limited extent. The use of these partial measures, however, does not indicate whether the input combination is better or worse than other possibilities. Thus a different and more complete measurement system is required.

One of the more complete productivity systems is the Total Factor Productivity (TFP) concept discussed earlier. In using TFP for inter-industry comparisons, Kendrick maintains that it is useful to use non-duplicative measures such as labor and capital, but when analyzing the costs of a firm or industry, intermediate inputs such as purchased materials and energy, are also relevant.[25/] He has also noted that utilities generally have a superior productivity record compared with the general economy. In large measure this results from the above average rate of investment in new plant and equipment. The latter are carriers of technical progress and represent the fruits of research

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25. Kendrick, J. W., "Some Productivity Issues in the Regulated Industries," chapter in Public Utility Productivity, cited earlier, p. 3-9.

and development. Since 1969, however, this above average rate of investment may be hurting more than helping. Total Factor Productivity for the electric utilities has exhibited very little overall growth since that year. This has resulted from the decline in fuel efficiency and the accelerated growth in capital input per Kw.[26] The latter indicates that inflation may have overtaken the productivity benefits normally derived from high investment rates.

The measurement of TFP is complicated and inexact, but appears to provide an adequate indicator. Kendrick has noted that the most practical efficiency improvement target is probably the current trend, or rate of increase, in the company's own TFP index. He recommends compilation of a 10-year record, and use of a moving average to eliminate erratic and cyclical influences.[27]

Computation of the TFP index requires the weighting of data in order to achieve a representative balance between inputs. The two major methods of computing the TFP index are the Laspeyres (also known as the Kendrick) and the Divisia. The Laspeyres method implicitly assumes that the weights will remain constant over time. In real life, this rarely occurs. There is also an assumption that the firm is a profit maximizer since unit input and output prices are used as weights. The result is a biased index.

The Divisia method uses physical input times unit price weighted

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26. Renshaw, E.F., "Productivity and the Demand for Electricity," Public Utility Fortnightly, May 6, 1976, p. 17-20.

27. Kendrick, J.W., "Efficiency Incentives and Cost Factors in Public Utility Automatic Revenue Adjustment Clauses," Bell Journal of Economics, cited earlier, p. 299-313.

by the share of respective revenue (or cost) out of the total for each year. As a consequence, it is not dependent on a fixed weighting system, and thus assumes variable inputs. Divisia is thus less restrictive in its assumptions, although the profit maximizing and neutral technology assumptions remain.[28]

The Divisia method was used by all parties for the computation of TFP indexes in the New Mexico case. PNM introduced a series covering the 1968 to 1977 period. This index was critiqued by Stevenson.[29] He maintained the PNM calculations made no distinction between customer class output although the various classes require different input levels; there have been substantial changes in sales by class since 1968 thus requiring an output weighting system in order to avoid an upward bias; purchased power is shown as a negative for several years whereas all inputs should be assumed to be positive; the residual was implicitly priced at a constant level which is implausible. Stevenson then recomputed the PNM index to take account of the above items. He also computed, on his own, a separate set of indexes. The latter was critiqued by PNM on two major grounds. In the first instance, he excluded net interchanges when negative. As a consequence, PNM was not credited with its full output. Stevenson also used the allowed rate of return on equity rather than that actually earned. The company stated this resulted in a further understatement in revenues. Thus, output was reduced relative to inputs making PNM appear less effi-

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28. Sudit, E.F., "Alternative Measures of Total Factor Productivity," Teleglobe Canada Symposium, May 1977.

29. Testimony of Rodney E. Stevenson, Case 1419, cited earlier.

cient.[30]

Given the various objections, the most appropriate TFP appears to be the PNM index as recomputed by Stevenson and including capital, fuel, labor, residual, and purchased power. Accordingly, we have used this as the appropriate measure of TFP. In line with Kendrick's suggestion that a moving average be used to smooth out erratic and cyclical influences, we have used a 2-year moving average. A longer cycle was not used because of the relatively short time period covered. In addition, in order to make it more convenient to detect the changes before and after COSI went into effect we have converted the moving average into an index in which 1974 = 100 (Table 6). This would be the last year before the implementation of COSI.

Based on these computations, it is apparent that PNM was less and less efficient each year, reaching a low point in 1975. A latter day high was reached in the 1976/77 period. The high, however, is still substantially below earlier levels.

One could surmise that the increase in TFP since 1975 was occasioned by the institution of COSI. A year or two of data, however, is too little to be regarded as a trend. At the least, the index indicates that there may have been sufficient lag built into COSI to avoid providing a disincentive. It is more likely that the increase experienced in 1976/77 period was not connected to COSI, but rather was the result of newer, more efficient generating units coming on-line. This would have a double barreled impact. Not only would heat rates and operating

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30. Brief of Respondent Public Service Company of New Mexico, Phase I, Case 1419, N.M.P.S.C., p. 49-50.

Table 6

A TOTAL FACTOR PRODUCTIVITY INDEX, 1968-77
PUBLIC SERVICE CO. OF NEW MEXICO

| Year | TFP [a] | Year | Moving Average [b] | Index [b] (1974 = 100) |
|---|---|---|---|---|
| 1968/69 | 1.032 | 1969 | 1.038 | 112 |
| 69/70 | 1.044 | 70 | 1.013 | 110 |
| 70/71 | 0.981 | 71 | 0.960 | 104 |
| 71/72 | 0.939 | 72 | 0.947 | 102 |
| 72/73 | 0.954 | 73 | 0.938 | 101 |
| 73/74 | 0.921 | 74 | 0.925 | 100 |
| 74/75 | 0.928 | 75 | 0.913 | 99 |
| 75/76 | 0.898 | 76 | 0.937 | 101 |
| 76/77 | 0.976 | | | |

a. Based on Stevenson revision of PNM, Case 1419, N.M.P.S.C.

b. Authors computations using Stevenson revision of PNM.

efficiency generally be improved, but capital inputs would tend to level off.

We can conclude from the above that while PNM's total factor productivity has improved since COSI was instituted, the increase was primarily due to other factors. It would appear that COSI was neither a positive nor a negative influence.

Financial Savings - One of the major benefits expected to accrue to PNM and to its customers as a result of the implementation of COSI is a reduction in the Company's cost of capital. Capital can be divided into three components: debt financing;[31/] preferred stock; and common equity. PNM must seek new investment capital in the financial markets where it is forced to compete with other companies (both regulated and unregulated) for the investor's dollar. Economic theory teaches that investors will be willing to supply financial capital to PNM if they perceive that the return on their investment will be at least equal to that which could be earned on alternative investments of similar risk. The investor's perception of risk thus becomes a determining factor in the rate of return demanded on a financial investment in PNM or in any other investment opportunity.

If COSI is perceived by investors as a method of reducing the financial risk of PNM's operations below what it would be under traditional ratemaking procedures, then it is logical to conclude that investors will be willing to accept a lower rate of return on their

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31. Only long-term debt financing will be considered in this paper, since short-term debt is a small proportion of the Company's total financing program, and is undertaken on a temporary basis.

investment in PNM than would be the case in the absence of COSI. The net result, then, would be a reduction in the cost of capital to the Company, and since the cost of capital is one of the components of the Company's cost of service, a reduced cost of capital will result in lower rates of charge to PNM's customers. What remains to be determined, then, is the effect, if any, of cost of service indexing on PNM's cost of capital.

Long-Term Debt Financing - During 1975 through 1978 period, PNM had three sales of long-term debt. The major provisions of these sales are outlined in Table 7, as are those for sales of other double-A rated utility bonds which were made at approximately the same time. Moody's average public utility Aa-rated bond yield for the months in which PNM and the other utilities listed in the table had long-term debt issues is also shown. From these data it is possible to make comparisons of the cost of long-term debt to PNM and to other similarly rated electric utilities for the period 1975-78.

If COSI has acted to reduce the financial risk of PNM's operations, as the Company and the Commission contended, then one would expect the cost of capital to the Company, including the cost of long-term debt, to be lower than that for other similarly rated companies. It is difficult, however, to ascertain the effect of a single factor (i.e., COSI) on the cost of capital to a utility over a particular period of time while other factors are also operating. PNM, however, is the only electric utility in the country subject to a COSI adjustment. While not guaranteeing a specific rate of return to the Company, COSI does act to reduce the regulatory lag experienced by PNM by largely eliminat-

Table 7

LONG TERM DEBT ISSUES OF PNM; OTHER SIMILARLY RATED ELECTRIC UTILITIES; AND MOODY'S AVERAGE Aa RATED BOND YIELDS, 1975-1978[a]

| Company | Date of Sale | Principal Amount | Maturity | Coupon Rate | Public Offering Sale | Underwriting Spread | Cost to the Company | Cost Differential to PNM | Bond Rating[b] |
|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
| (1975) | | $ | | | | | | | |
| Public Service of New Mex. | 3/12/75 | 25,000,000 | 2005 | 9 1/8% | $100.00 | 0.875% | 9.21% | - | Aa/AA |
| Duquesne Light | 3/12/75 | 50,000,000 | 2005 | 9 1/2 | 100.297 | 0.987 | 9.57 | +0.36% | Aa/AA |
| Central Illinois Light | 2/23/75 | 25,000,000 | 2005 | 9 1/4 | 100.75 | 1.073 | 9.28 | +0.07 | Aa/AA |
| Moody's Average Bond Yield | Feb. '75 | | | 9.23 | | | | +0.105 | Aa |
| | March '75 | - | - | 9.17 | - | - | - | +0.045 | Aa |
| (1977) | | | | | | | | | |
| Public Service of New Mex. | 6/8/77 | 30,000,000 | 2007 | 8 1/8 | 99.72 | 0.765 | 8.22 | - | Aa/AA |
| Kansas Power & Light | 6/22/77 | 30,000,000 | 2007 | 8 1/8 | 99.50 | 0.875 | 8.25 | +0.03 | Aa/AA |
| Moody's Average Bond Yield | June '77 | - | - | 8.37 | - | - | - | +0.245 | Aa |
| (1978) | | | | | | | | | |
| Public Service of New Mex. | 4/25/78 | 65,000,000 | 2008 | 9.0 | 99.00 | 0.517 | 9.15 | - | Aa/AA |
| Cincinnati Gas & Elec. | 4/20/78 | 75,000,000 | 2008 | 9 1/8 | 101.289 | 0.454 | 9.04 | (0.11) | Aa/AA |
| Moody's Average Bond Yield | April '78 | - | - | 8.86 | - | - | - | (0.14) | Aa |

a. Source: Analysis of Public Utility Financing, Year 1975, 1976, 1977, 1978; EBASCO Services, Inc., and Moody's Bond Record, January 1979, Year End Edition; Moody's Investors Service, Inc.

b. Bond Rating by Moody's Investors Service and Standard & Poor, respectively.

ing the uncertainty of the timing and the amount of rate relief to the Company. No other electric utility listed in Table 7, and considered in this analysis, has this benefit.

The operation of the financial market, which is essentially beyond the influence of any particular company (utility or non-utility) tends to equalize the rate of return on investment in companies of similar risk. That is, all of the factors which affect the risk perception of investors and thus determine the rate of return required in any investment are reflected in the cost of capital to the company at any particular point in time. Thus, by comparing the cost of long-term debt to PNM and to other electric utility companies at similar points in time, the influence of those factors which affect each company's cost of capital (such as interest coverage, construction program, capitalization, and AFUDC as a percentage of net income), is reflected in the rate of return demanded by the financial community. Any difference in the rate of return demanded by the financial community from the various companies, then, reflects the difference in risk perception of investors in each company's operations. By comparing electric utility companies with identical long-term bond ratings (a measure of the quality of earnings for a particular company), the influence of those factors affecting the rate of return required by investors tends to be equalized. Since PNM is the only electric utility operating with a COSI, any difference in the rate of return demanded by investors in PNM's long-term debt as compared with that of other identically rated electric utilities should reflect the unique effect of COSI in the operations of PNM.

The rate of return required on PNM's long-term debt can also be compared with the average return on double A-rated utility bonds for the same period of time as determined by Moody's Investors Service and listed in Table 7. Although this measure of required rate of return is simply an average of yields on long-term bond issues for the months indicated, and includes issues of varying amounts and maturities, it does provide an indication over time of PNM's performance as compared to that of other utilities. The table shows that the relative cost advantage of PNM long-term debt over that of other electric utilities during the period February 1975 through June 1977 has reversed itself and become a relative disadvantage in April 1978.

The long-term effect of COSI on the cost of debt to PNM can be interpreted as having no significant impact on the cost of this method of financing to the Company. This interpretation is based on the following observations:

1) In March 1975, shortly after the announcement of the implementation of COSI, the cost of debt to PNM was 0.36 percent below that of a similar sale on the same day but only 0.07 percent below that of a similar sale three weeks prior and 0.045 percent below the average yield of Aa-rated utility bonds for the same month. The relative cost advantage of PNM debt to that of these other cost indices can be attributed to the impact of the COSI implementation announcement.

2) In June of 1977, PNM's long-term debt sale on the 8th of the month enjoyed a 0.22 percent advantage over the average yield of Aa-rated utility bonds for the same month but only a 0.03 percent advantage over a similar sale two weeks following. The relatively favorable

financial performance of PNM as opposed to that of other utilities as represented by the Moody's average utility bond yield can be attributed to the financial community's continued belief that COSI would enable PNM to achieve its allowed rate of return.

3) The relatively unfavorable financial performance of PNM in relation to a similar bond sale in April 1978 and to Moody's April 1978 average utility bond yield indicates the financial community's realization that the COSI mechanism did not result in the Company consistently earning its allowed rate of return. Thus, while the short-run effect of COSI was to reduce the cost of long-term debt to PNM, in the long run it appears that the effect is minimal. It is more important to earn the allowed rate of return than to have COSI or any other mechanism. This conclusion was supported by comments made by members of the financial community.

Preferred Stock Financing - Table 8 lists PNM preferred stock financings for the 1975 through 1978 period, along with sales of preferred stock by similarly rated electric utility companies during the same time period, along with Moody's average a-rated preferred stock yields. As is the case for long-term debt, a comparison of the cost of preferred stock issues for PNM and for other similarly rated electric utility companies over the same time period should reveal what effect, if any, COSI has had on the cost of this method of investment financing.

Although less explicit than the data on long-term debt presented earlier (due to the lack of sales of similarly rated electric utility preferred stock) the data presented in Table 8 shows the same general

Table 8

PREFERRED STOCK SALES OF PNM; OTHER SIMILARLY RATED ELECTRIC UTILITIES; AND MOODY'S AVERAGE a-RATED PREFERRED STOCK YIELDS, 1975-1978[a]

| | Date of Sale | Number of Shares | Dividend Yield | Public Offering Price | Under-writing Spread | Cost to the Company | Cost dif-ferential to PNM | Preferred Stock Rating[b] |
|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
| (1975) | | | | | | | | |
| Public Service of New Mexico | 3/12/75 | 100,000 | 10.12% | $100.00 | 1.25% | 10.25% | - | a/A |
| Iowa Power and Light | 3/20/75 | 100,000 | 10.20 | 100.00 | 1.50 | 10.36 | +0.11% | a/A |
| Moody's Average Preferred Stock Yield | March'75 | - | - | - | - | - | - | a |
| (1976) | | | | | | | | |
| Public Service of New Mexico | 6/3/76 | 800,000 | 9.16 | 25.00 | 3.60 | 9.50 | - | a/A |
| Pennsylvania Power and Light | 6/8/76 | 750,000 | 9.24 | 100.00 | 1.25 | 9.36 | (0.14) | a/A |
| Potomac Edison | 6/17/76 | 150,000 | 9.50 | 101.473 | 1.449 | 9.64 | +0.14 | a/A |
| Moody's Average Preferred Stock Yield | June'76 | - | 9.46 | - | - | - | +0.30 | a |
| (1977) | | | | | | | | |
| Public Service of New Mexico | 3/24/77 | 200,000 | 8.48 | 100.00 | 1.20 | 8.58 | - | a/A |
| Iowa Power and Light | 3/23/77 | 150,000 | 8.50 | 100.00 | 1.14 | 8.60 | +0.02 | a/AA |
| El Paso Electric | 4/20/77 | 100,000 | 8.30 | 99.277 | 0.966 | 8.38 | (0.20) | a/A |
| Moody's Average Preferred Stock Yield | March'77 | - | 9.01 | - | - | - | +0.53 | a |
| | April'77 | - | 9.00 | - | - | - | +0.52 | a |
| (1978) | | | | | | | | |
| Public Service of New Mexico | 3/29/78 | 260,000 | 8.80 | 100.00 | 1.05 | 8.89 | - | a/A |
| Iowa Public Service | 2/8/78 | 150,000 | 8.52 | 100.00 | 0.971 | 8.60 | (0.29) | a/A+ |
| Washington Water Power | 3/8/78 | 250,000 | 9.00 | 100.00 | 1.15 | 9.10 | +0.21 | baa/A- |
| Moody's Average Preferred Stock Yield | Feb.'78 | | 8.74 | | - | | (0.06) | a |
| | March'78 | | 8.79 | | - | - | (0.01) | a |

a. Source: Analysis of Public Utility Financing, Year 1975, 1976, 1977, 1978; EBASCO Services, Inc. and Moody's Bond Record, January 1979, Year End Edition; Moody's Investors Service, Inc.

b. Preferred Stock rating of Moody's Investors Service and Standard & Poor's respectively.

price differential trend between the cost of preferred stock to PNM and that to other utility companies. In March of 1975, a sale of preferred stock by PNM enjoyed a 0.11 percent cost advantage over a similar sale eight days later. In June of 1976, PNM's sale of preferred stock on the 3rd of the month was 0.14 percentage points above that of a similar sale which took place the 8th of the month and 0.14 percentage points below a sale on the 17th of the month. The cost differential between PNM and Moody's average preferred stock yield for June 1976 was 0.30 percent. The cost differential between PNM and Moody's average preferred stock yield increased to 0.53 percent for March 1977. However, PNM's sale on March 24 at a cost to the Company of 8.58 percent is 0.20 percent above a similar sale by El Paso Electric on April 20, 1977 at a cost of 8.38 percent. During this same period, the yield on Moody's average public utility preferred stocks decreased from 9.01 percent for March 1977 to 9.00 percent for April 1977. Thus, while the average yield on utility preferred stock for the March and April 1977 period declined only 0.01 percentage points, the cost to El Paso Electric declined by 0.20 percentage points in relation to the month earlier sale by PNM.

In March 1978 the yield on Moody's average public utility preferred stock was approximately the same as that for PNM (8.79 percent vs. 8.80 percent) after having been 0.53 percentage points above PNM in March 1977 (9.01 percent vs. 8.48 percent). This fact, taken together with the lack of any clear, consistent evidence from the data presented in Table 8 for a favorable cost differential between PNM preferred stock sales and those of other electric utility companies, indicates

that there are no significant savings related to preferred stock financing accruing to PNM as the result of the COSI methodology.

Common Equity Financing - Determining the effect of COSI on the cost of common equity to PNM is more difficult than determining its effect on the cost of long-term debt or on preferred stock. Common equity has no maturity date or fixed interest rate. The market value of a share of common equity and the rate of return earned on that share of stock will rise or fall in relation to investors' perceptions of the current financial status of a particular company and expectations of the flow of future earnings to the company. Other factors such as current and expected future short-and-long term interest rates, the business cycle, and governmental actions also have an effect on the price of common equity shares generally. As with long-term debt and preferred stock financing, it is extremely difficult to determine the effect of a single event on the cost of common equity financing to a company. The reaction of investors to a particular event, and thus its effect on the cost of equity capital, must be determined indirectly through inferences based on empirical evidence.

The effect of COSI on the cost of common equity capital to PNM may be determined by comparing the market performance of PNM's common equity with the market performance of the common equity of a group of similar electric utility companies over an appropriate period of time. A group of similarly situated electric utilities is selected because, due to their similarity to PNM, the financial market performance of the stocks of these companies can be expected to be roughly equivalent to that of

PNM's. Any significant difference in the market performance of PNM vis-a-vis that of the others may be presumed to be due to the operation of COSI.

The group of companies chosen for comparison with PNM are those listed earlier in Table 1. Selected financial data averaged for the nine comparison companies and for PNM for the period 1974 through 1977 is shown in Table 9. All of the data contained in this table are average annual values as derived from financial information contained in "The Value Line Investment Survey."

The effect of COSI on the cost of common equity capital to PNM can be determined by comparing the relative market performance of PNM's common equity vis-a-vis the nine comparison companies over the four year period, 1974 through 1977, as expressed in the relative changes in each firm's P/E ratio and Market/Book ratio.

The P/E ratio is an indication of investor confidence in each utility's current earnings and expected future earnings. Similarly, the Market/Book ratio indicates investors' evaluation of each company's earnings in relation to the current cost of common equity capital. One of the major goals of the New Mexico Commission when it initiated COSI, was the achievement of a Market/Book ratio for PNM of approximately 1.25.[32/] If the Commission, in instituting COSI, has achieved its goal of reducing the perceived risk of investment in PNM and thereby reducing the Company's cost of common equity capital, then one would expect the market performance of PNM common stock, as reflected in its P/E ratio

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32. Decision and Order of the New Mexico Public Service Commission, Case No. 1196, April 22, 1975, p. 23.

Table 9

AVERAGE VALUES OF SELECTED FINANCIAL INFORMATION AND FINANCIAL RATIOS FOR NINE COMPANIES & FOR THE PUBLIC SERVICE CO. OF NEW MEXICO 1974-1977[a/]

Average of Nine Comparison Companies

| Year | Price/ Share | Earn/ Share | P/E Ratio | Dividend Payout | Market/ Book |
|---|---|---|---|---|---|
| 1977 | $22.81 | $2.75 | 8.3 | 65.8% | 1.13 |
| 1976 | 21.02 | 2.47 | 8.5 | 70.0 | 1.10 |
| 1975 | 18.48 | 2.40 | 7.7 | 69.2 | 1.00 |
| 1974 | 16.76 | 2.14 | 7.8 | 75.7 | 0.94 |
| % Change | 36.10% | 28.5% | 6.4% | (13.08%) | 20.21% |

Public Service of New Mexico

| Year | Price/ Share | Earn/ Share | P/E Ratio | Dividend Payout | Market/ Book |
|---|---|---|---|---|---|
| 1977 | $21.89 | $2.46 | 8.9 | 65.4% | 1.04 |
| 1976 | 20.30 | 2.16 | 9.4 | 65.7 | 0.00 |
| 1975 | 17.08 | 2.44 | 7.0 | 51.6 | 0.85 |
| 1974 | 14.04 | 1.95 | 7.2 | 62.5 | 0.73 |
| % Change | 55.9% | 26.15% | 23.6% | 4.64% | 42.46% |

a. Source: Derived from the Value Line Investment Survey.

and Market/Book ratio, to outperform that of other similar electric utilities. If COSI has not achieved its goal, then one would expect the market performance of PNM common equity to be essentially the same as that of the comparison companies.

Electric utility common equity is purchased primarily as an income producing investment. The Dividend Payout ratio, as an indication of the percentage of income available for common equity which is paid out to the shareholder as dividends, of a company can have a large impact on the value placed on its common equity and thus can affect the firm's P/E ratio and Market/Book ratio. A significant increase in an electric utility's Dividend Payout ratio would likely cause an increase in the company's P/E ratio and Market/Book ratio. However, a high current Dividend Payout ratio may have a negative effect on the price of the company's common equity since it indicates a likely low growth rate in future dividends.

A comparison of the percentage change in PNM's P/E ratio and Market/Book ratio with that of the nine comparison companies shows that PNM has outperformed each of these companies over the four-year period 1974-1977. Only two other companies, however, Public Service of Indiana and Iowa Power & Light, showed an increase in their Dividend Payout ratio during this period of time; a factor which would likely have a positive effect on each company's P/E ratio and Market/Book ratio. However, PNM also outperformed these companies in terms of the percentage increase in its financial ratios. Table 9 shows the average values of each of the financial variables for the nine comparison companies for the period 1974 through 1977. This table also shows

the percentage change for PNM. The average of the nine comparison companies shows a 6.4 percent increase in the P/E ratio for the four-year period while PNM shows a 23.6 percent increase. Also, the average increase in the Market/Book ratio for the nine companies was 20 percent, while PNM showed a 42 percent increase. The nine companies, however, averaged a 13 percent decrease in their Dividend Payout ratio during the same time that PNM showed a 5 percent increase in its dividend payout. It seems unlikely, however, that this relative difference in Dividend Payout ratio could explain the relatively poor performance of the nine comparison companies in relation to that of PNM. The data appear to indicate that COSI has had a favorable impact on the cost of common equity capital to PNM.

There remains one question, then, as to why it appears that COSI has had a favorable impact on the cost of common equity capital to PNM while at the same time there seems to have been no significant impact on the cost of long-term debt or preferred stock. First of all, the information on recent preferred stock financings of PNM is somewhat sketchy in that few financings of similar quality stock issues took place at the approximate time of the PNM sales. However, even though the available information may not be totally conclusive, with the lack of any clear indication of a cost advantage accruing to PNM as a result of COSI, it must be concluded that COSI has not had a significant impact on PNM's cost of preferred stock capital.

In regard to long-term debt financing, it appears that PNM enjoyed a relative cost advantage over sales of similar issues for a period of time. That advantage, however, seems to have dissipated. As with

preferred stock sales, however, it is difficult to observe a significant variance in costs among the several utility company sales based upon three sales of PNM long-term debt over a three-year period.

The effect of COSI on the cost of capital to PNM is likely to be mainly reflected in the cost of common equity to the Company. Data on the market performance of PNM common equity is based on a large number of financial market transactions, not only on a few sales as is the case with long-term debt or preferred stock. Also, COSI is tied to the rate of return earned on common equity capital for PNM rather than to the cost of total invested capital. The purpose of COSI is to enable PNM to better maintain an earned rate of return on its jurisdictional common equity investment similar to that rate of return established by the Commission. It is the actual earned rate of return on jurisdictional common equity capital that triggers the COSI mechanism to cause an adjustment to PNM's service rates. Thus, the effect of COSI on the Company's cost of capital is likely to be expressed through the financial market performance of PNM common stock.

Initial cost of capital savings are likely to be the result of the immediate, short-term reaction of the financial market to the announcement of COSI's implementation. Only over a period of time, as the market analyzes the actual financial performance of PNM under the COSI mechanism, will the financial community's evaluation of COSI become known. During the period 1975 through 1977, PNM's actual rate of return on jurisdictional common equity was consistently below the minimum rate established by the Commission. Thus, even though COSI acted to reduce the level of regulatory lag experienced by the company,

and eliminated much of the risk involved in determining the amount and the timing of rate relief to the Company, it did not result in PNM actually earning its allowed rate of return on common equity investment. It appears that after an initially favorable reaction, the financial community's evaluation of COSI has turned less favorable over time. The data contained in Table 7 seem to bring this point out, by indicating a relative cost advantage for PNM's long-term debt during 1975 and 1977, but showing no such advantage in 1978.

## ALTERNATIVES TO COSI

Traditional ratemaking procedures offer an opportunity for all interested parties to participate in the ratemaking process and give the Commission and its staff the opportunity to investigate a utility's operations and to ensure that it is operating efficiently. Traditional ratemaking procedures also take up a considerable amount of time. During periods of rapid inflation, the rates established at the conclusion of the ratemaking process are likely to produce revenues to the company which are inadequate to recover the current costs of service and provide a reasonable rate of return on investment capital. This is so because current rate schedules are based on test period costs which are usually 12 to 18 months out of date by the time a rate proceeding is concluded.

As a consequence, traditional ratemaking procedure has developed a number of adjustment mechanisms designed to increase the likelihood of a utility actually earning its allowed rate of return.

### Alternatives

1) An attrition allowance (the concept of which was discussed

earlier), designed to allow for the fact that a company's rate base is increasing at costs above those of historic levels.

2) Year-end rate base; design tariffs to produce revenues based on year-end levels of investment and costs of service as opposed to average test-year levels.

3) Adjustment for known cost increases; adjust test-year results for known cost increases which have occured during the ratemaking process.

4) Future test year; use an estimated future test year's investment and costs of service figures as a basis upon which to establish revenue requirements.

5) Inclusion of construction work in progress (CWIP), all or some part thereof, in the company's rate base.

These adjustments may be seen as minor alterations to traditional ratemaking procedures rather than as major deviations from the process.

In spite of these adjustments to the ratemaking process, most utility companies have failed to earn, on any consistent basis, the rate of return allowed by regulatory commissions. Also, as we have seen, COSI has not resulted in PNM earning its allowed rate of return on any consistent basis. It does appear to have reduced the Company's cost of capital somewhat, at least on a short-term basis.

Modified Indexing

COSI could be modified by tying the proportion of costs passed through to the rate of inflation. That is, if inflation were at 5%, 50% of costs would be subject to COSI; a 10% inflation rate would allow

a 100% pass through. This would permit COSI to come into being when inflation was worst, and COSI was most needed.

A variation of the above would be a COSI with variable lag. That is, adjustments would be made monthly when the inflation rate is 10% or more, quarterly when it is 8%, semi-annually at 6% inflation, etc.

The Kendrick proposal has been discussed in detail earlier in this report and this discussion will not be repeated here. Suffice it to say, this proposal increases the incentive for efficiency while raising administrative costs relative to COSI.

Another alternative would vary the pass through based on the controllability of an item by the utility. That is, an item beyond the control of the company would have a 100% pass through; those completely controllable would have no pass through.

It is obvious that, while COSI provided for automatic quarterly adjustments to PNM's service rates, it does not alleviate the necessity for periodic rate proceedings. This is also true of the other forms of comprehensive automatic adjustment mechanisms since, if for no other reason, an occasional rate proceeding would be necessary simply to review and possibly modify the rate of return and the operation of the AAC. None of these other forms of AAC's, however, with the exception of the Kendrick cost and efficiency adjustment clause, addresses itself to the other regulatory issues involved in a rate proceeding. Even the Kendrick proposal addresses only one of these issues - efficiency of operation - and has nothing to say about such matters as plant siting, financing, rate structure or demand projections.

# APPENDIX A

## Persons Interviewed

1. Steven Asher, Office of New Mexico Attorney General, Santa Fe.
2. Marjorie Jones, Merrill Lynch, Pierce, Fenner and Smith, New York.
3. Theodore J. Komosa, Merrill Lynch, Pierce, Fenner and Smith, New York.
4. Mark Luftig, Salomon Bros., New York.
5. Charles D. Olmsted, Olmsted and Cohen, Santa Fe.
6. Albert J. Robison, Public Service Co. of New Mexico, Albuquerque.
7. Robert Swartwout, New Mexico Public Service Commission, Santa Fe.

# APPENDIX B

## Individual Company Data

Table A1

TYPICAL ELECTRIC BILLS FOR CENTRAL ILLINOIS PUBLIC SERVICE COMPANY RESIDENTIAL AND COMMERCIAL SERVICE, JAN. 1974-JAN. 1977[a]

| Central Illinois Pub.Serv. | Jan. 1, 1974 | Jan. 1 1975 | Jan. 1, 1976 | Jan. 1 1977 | % Change 1974-1977 |
|---|---|---|---|---|---|
| Residential Service | | | | | |
| 250 Kwh/month | $ 9.76 | $10.51 | $12.17 | $13.15 | 34.7% |
| 500 Kwh/month | 13.97 | 15.22 | 18.25 | 19.78 | 41.6 |
| 750 Kwh/month | 18.92 | 20.68 | 25.19 | 27.18 | 43.7 |
| 1000 Kwh/month | 25.22 | 27.56 | 33.59 | 36.24 | 43.7 |
| Commercial Service | | | | | |
| 6.0 Kw/750 Kwh | - | - | - | - | - |
| 12.0 Kw/1,500 Kwh | - | - | - | - | - |
| 30.0 Kw/6,000 Kwh | - | - | - | - | - |
| 40.0 Kw/10,000 Kwh | - | - | - | - | - |

a. Source: Federal Power Commission, Typical Electric Bills 1974, 1975, 1976, 1977, Various Tables.

Table A2

TYPICAL ELECTRIC BILLS FOR CLEVELAND ELECTRIC ILLUMINATING COMPANY
RESIDENTIAL AND COMMERCIAL SERVICE, JAN. 1974-JAN. 1977

| Cleveland Elec. Illum. | Jan. 1, 1974 | Jan. 1 1975 | Jan. 1 1976 | Jan. 1 1977 | % Change 1974-1977 |
|---|---|---|---|---|---|
| Residential Service | | | | | |
| 250 Kwh/month | $ 8.28 | $ 11.52 | $10.96 | $13.44 | 62.3% |
| 500 Kwh/month | 12.53 | 19.85 | 20.72 | 25.98 | 107.3 |
| 750 Kwh/month | 16.74 | 28.12 | 30.18 | 38.32 | 128.9 |
| 1000 Kwh/month | 21.44 | 36.90 | 39.64 | 50.66 | 136.3 |
| Commercial Service | | | | | |
| 6.0 Kw/750 Kwh | 28.75 | 38.72 | 37.03 | 44.82 | 55.9 |
| 12.0 Kw/1,500 Kwh | 55.98 | 77.05 | 73.65 | 88.66 | 58.4 |
| 30.0 Kw/6,000 Kwh | 183.72 | 274.79 | 266.62 | 330.33 | 79.8 |
| 40.0 Kw/10,000 Kwh | 285.20 | 429.58 | 414.16 | 512.95 | 79.9 |

Source: Federal Power Commission, Typical Electric Bills 1974, 1975, 1976, 1977, Various Tables

Table A3

TYPICAL ELECTRIC BILLS FOR ILLINOIS POWER COMPANY
RESIDENTIAL AND COMMERCIAL SERVICE, JAN. 1974-JAN. 1977

| Illinois Power | Jan. 1 1974 | Jan. 1, 1975 | Jan. 1, 1976 | Jan. 1, 1977 | % Change 1974-1977 |
|---|---|---|---|---|---|
| Residential Service | | | | | |
| 250 Kwh/month | $ 8.12 | $ 8.79 | $ 9.26 | $ 10.01 | 23.3% |
| 500 Kwh/month | 14.15 | 15.51 | 16.76 | 18.27 | 29.1 |
| 750 Kwh/month | 19.99 | 22.07 | 24.16 | 26.43 | 32.2 |
| 1000 Kwh/month | 25.84 | 28.62 | 31.56 | 34.59 | 33.9 |
| Commercial Service | | | | | |
| 6.0 Kw/750 Kwh | 27.71 | 30.42 | 33.34 | 35.62 | 28.5 |
| 12.0 Kw/1,500 Kwh | 54.83 | 60.19 | 66.02 | 70.57 | 28.7 |
| 30.0 Kw/6,000 Kwh | 197.25 | 215.25 | 236.28 | 254.46 | 29.0 |
| 40.0 Kw/10,000 Kwh | 288.56 | 317.37 | 348.32 | 378.61 | 31.2 |

Source: Federal Power Commission, Typical Electric Bills 1974, 1975, 1976, 1977, Various Tables.

Table A4

TYPICAL ELECTRIC BILLS FOR INDIANAPOLIS POWER AND LIGHT COMPANY
RESIDENTIAL AND COMMERCIAL SERVICE, JAN. 1974-JAN. 1977

| Indianapolis Power & Light | Jan. 1, 1974 | Jan. 1, 1975 | Jan. 1, 1976 | Jan. 1 1977 | % Change 1974-1977 |
|---|---|---|---|---|---|
| Residential Service | | | | | |
| 250 Kwh/month | $ 7.93 | $ 7.93 | $ 9.44 | $ 10.04 | 26.67% |
| 500 Kwh/month | 11.28 | 11.28 | 13.68 | 17.40 | 54.3 |
| 750 Kwh/month | 15.03 | 15.03 | 18.39 | 23.21 | 54.4 |
| 1000 Kwh/month | 18.78 | 18.78 | 23.09 | 29.47 | 56.9 |
| Commercial Service | | | | | |
| 6.0 Kw/750 Kwh | 26.96 | 26.96 | 31.91 | 35.14 | 30.3 |
| 12.0 Kw/1,500 Kwh | 49.46 | 49.46 | 58.77 | 64.86 | 31.1 |
| 30.0 Kw/6,000 Kwh | 166.46 | 166.46 | 199.66 | 231.26 | 38.9 |
| 40.0 Kw/10,000 Kwh | 246.46 | 246.46 | 297.74 | 341.83 | 38.7 |

Source: Federal Power Commission, Typical Electric Bills 1974, 1975, 1976, 1977, Various Tables.

Table A5

TYPICAL ELECTRIC BILLS FOR IOWA POWER AND LIGHT COMPANY
RESIDENTIAL AND COMMERCIAL SERVICE, JAN. 1974-JAN. 1977

| Iowa Power & Light | Jan. 1, 1974 | Jan. 1, 1975 | Jan. 1, 1976 | Jan. 1, 1977 | % Change 1974-1977 |
|---|---|---|---|---|---|
| Residential Service | | | | | |
| 250 Kwh/month | $ 9.49 | $ 9.96 | $ 12.28 | $ 12.33 | 29.9% |
| 500 Kwh/month | 13.13 | 13.97 | 17.72 | 18.30 | 39.4 |
| 750 Kwh/month | 19.17 | 20.58 | 26.15 | 27.28 | 42.3 |
| 1000 Kwh/month | 25.41 | 27.69 | 35.08 | 36.75 | 44.6 |
| Commercial Service | | | | | |
| 6.0 Kw/750 Kwh | 29.52 | 32.38 | 39.30 | 41.15 | 39.4 |
| 12.0 Kw/1,500 Kwh | 54.24 | 59.11 | 72.10 | 75.95 | 40.0 |
| 30.0 Kw/6,000 Kwh | 183.36 | 202.29 | 251.68 | 267.55 | 45.9 |
| 40.0 Kw/10,000 Kwh | 287.20 | 316.85 | 398.60 | 425.15 | 48.0 |

Source: Federal Power Commission, Typical Electric Bills 1974, 1975, 1976, 1977, Various Tables.

Table A6

TYPICAL ELECTRIC BILLS FOR IOWA PUBLIC SERVICE COMPANY
RESIDENTIAL AND COMMERCIAL SERVICE, JAN. 1974-JAN. 1977

| Iowa Public Service | Jan. 1, 1974 | Jan. 1, 1975 | Jan. 1, 1976 | Jan. 1, 1977 | % Change 1974-1977 |
|---|---|---|---|---|---|
| Residential Service | | | | | |
| 250 Kwh/month | $ 9.88 | $ 10.70 | $ 13.15 | $ 14.04 | 42.1% |
| 500 Kwh/month | 14.88 | 16.17 | 19.56 | 21.33 | 43.3 |
| 750 Kwh/month | 21.41 | 23.48 | 28.11 | 30.76 | 43.7 |
| 1000 Kwh/month | 28.36 | 31.40 | 37.93 | 41.47 | 46.2 |
| Commercial Service | | | | | |
| 6.0 Kw/750 Kwh | 37.15 | 39.93 | 50.85 | 53.50 | 44.0 |
| 12.0 Kw/1,500 Kwh | 69.75 | 75.47 | 97.61 | 102.92 | 47.6 |
| 30.0 Kw/6,000 Kwh | 230.69 | 252.00 | 333.32 | 354.55 | 53.7 |
| 40.0 Kw/10,000 Kwh | 359.70 | 392.60 | 521.53 | 556.92 | 54.8 |

Source: Federal Power Commission, Typical Electric Bills 1974, 1975, 1976, 1977, Various Tables.

Table A7

TYPICAL ELECTRIC BILLS FOR KANSAS POWER AND LIGHT COMPANY
RESIDENTIAL AND COMMERCIAL SERVICE, JAN. 1974-JAN. 1977

| Kansas Power and Light | Jan. 1, 1974, | Jan. 1, 1975 | Jan. 1, 1976 | Jan. 1, 1977 | % Change 1974-1977 |
|---|---|---|---|---|---|
| Residential Service | | | | | |
| 250 Kwh/month | $ 5.87 | $ 6.61 | $ 8.93 | $ 11.18 | 90.5% |
| 500 Kwh/month | 9.85 | 11.33 | 14.45 | 18.94 | 92.3 |
| 750 Kwh/month | 13.86 | 16.07 | 20.74 | 27.49 | 98.3 |
| 1000 Kwh/month | 17.88 | 20.83 | 27.04 | 36.01 | 101.4 |
| Commercial Service | | | | | |
| 6.0 Kw/750 Kwh | 30.50 | 32.71 | 35.03 | 41.78 | 37.0 |
| 12.0 Kw/1,500 Kwh | 50.88 | 55.33 | 63.19 | 76.66 | 50.7 |
| 30.0 Kw/6,000 Kwh | 171.74 | 190.97 | 230.37 | 284.28 | 65.5 |
| 40.0 Kw/1,000 Kwh | 247.25 | 277.01 | 340.25 | 430.05 | 73.9 |

Source: Federal Power Commission, Typical Electric Bills 1974, 1975, 1976, 1977, Various Tables.

Table A8

TYPICAL ELECTRIC BILLS FOR NORTHERN INDIANA PUBLIC SERVICE CORP.
RESIDENTIAL AND COMMERCIAL SERVICE, JAN. 1974-JAN. 1977

| Northern Indiana Pub. Serv. | Jan. 1, 1974 | Jan. 1, 1975 | Jan. 1, 1976 | Jan. 1, 1977 | % Change 1974- |
|---|---|---|---|---|---|
| Residential Service | | | | | |
| 250 Kwh/month | $ 8.71 | $ 10.36 | $ 11.44 | $ 11.63 | 33.5% |
| 500 Kwh/month | 12.04 | 14.85 | 19.55 | 19.94 | 65.6 |
| 750 Kwh/month | 17.15 | 21.27 | 27.67 | 28.24 | 64.7 |
| 1000 Kwh/month | 23.08 | 28.58 | 35.78 | 36.55 | 58.4 |
| Commercial Service | | | | | |
| 6.0 Kw/750 kwh | 38.97 | 45.11 | 42.65 | 43.22 | 10.9 |
| 12.0 Kw/1,500 Kwh | 74.96 | 87.28 | 96.06 | 97.21 | 29.7 |
| 30.0 Kw/6,000 Kwh | 220.59 | 262.17 | 283.87 | 288.49 | 30.8 |
| 40.0 Kw/10,000 Kwh | 315.34 | 378.71 | 424.43 | 432.12 | 37.0 |

Source: Federal Power Commission, Typical Electric Bills 1974, 1975, 1976, 1977, Various Tables.

Table A9

TYPICAL ELECTRIC BILLS FOR PUBLIC SERVICE OF INDIANA
RESIDENTIAL AND COMMERCIAL SERVICE, JAN. 1974-JAN. 1977

| Public Serv. of Indiana | Jan. 1, 1974 | Jan. 1, 1975 | Jan. 1, 1976 | Jan. 1, 1977 | % Change 1974-1977 |
|---|---|---|---|---|---|
| Residential Service | | | | | |
| 250 Kwh/month | $ 10.70 | $ 11.03 | $ 13.81 | $ 14.39 | 34.5% |
| 500 Kwh/month | 14.16 | 14.83 | 20.50 | 21.64 | 52.8 |
| 750 Kwh/month | 18.26 | 19.27 | 27.02 | 28.73 | 57.3 |
| 1000 Kwh/month | 22.57 | 23.90 | 33.33 | 35.63 | 57.9 |
| Commercial Service | | | | | |
| 6.0 Kw/750 Kwh | 35.65 | 36.61 | 43.36 | 45.06 | 26.4 |
| 12.0 Kw/1,500 Kwh | 63.13 | 65.05 | 77.07 | 80.49 | 27.5 |
| 30.0 Kw/6,000 Kwh | 174.82 | 182.58 | 219.23 | 233.01 | 33.3 |
| 40.0 Kw/10,000 Kwh | 256.91 | 269.88 | 329.44 | 352.44 | 37.2 |

Source: Federal Power Commission, Typical Electric Bills 1974, 1975, 1976, 1977, Various Tables.

Table A10

TYPICAL ELECTRIC BILLS FOR PUBLIC SERVICE OF NEW MEXICO
RESIDENTIAL AND COMMERCIAL SERVICE, JAN. 1974-JAN.1977

| Pub. Serv. of New Mexico | Jan.1, 1974 | Jan.1, 1975 | Jan.1, 1976 | Jan.1, 1977 | % Change 1974-1977 |
|---|---|---|---|---|---|
| Residential Service | | | | | |
| 250 Kwh/month | $ 7.92 | $ 9.35 | $ 9.91 | $ 10.61 | 34.0% |
| 500 Kwh/month | 10.55 | 16.31 | 17.42 | 18.82 | 78.4 |
| 750 Kwh/month | 14.97 | 22.36 | 24.43 | 26.53 | 77.2 |
| 1000 Kwh/month | 20.29 | 27.82 | 30.69 | 33.49 | 65.1 |
| Commercial Service | | | | | |
| 6.0 Kw/750 Kwh | 28.92 | 32.86 | 35.28 | 37.38 | 29.3 |
| 12.0 Kw/1,500 Kwh | 51.64 | 62.73 | 67.56 | 71.75 | 38.9 |
| 30.0 Kw/6,000 Kwh | 157.96 | 189.91 | 209.24 | 226.02 | 43.1 |
| 40.0 Kw/10,000 Kwh | 258.14 | 297.19 | 329.40 | 357.36 | 38.4 |

Source: Federal Power Commission, Typical Electric Bills 1974, 1975, 1976, 1977, Various Tables.

Table A11

AVERAGE TYPICAL ELECTRIC BILLS FOR NINE SELECTED UTILITY COMPANIES
RESIDENTIAL AND COMMERCIAL SERVICE, JAN. 1974-JAN. 1977

| Average of Nine Selected Utilities | Jan. 1, 1974 | Jan. 1, 1975 | Jan. 1, 1976 | Jan. 1, 1977 | % Change 1974-1977 |
|---|---|---|---|---|---|
| Residential Service | | | | | |
| 250 Kwh/month | $ 8.74 | $ 9.71 | $ 11.27 | $ 12.25 | 40.2% |
| 500 Kwh/month | 12.89 | 14.78 | 17.91 | 20.18 | 56.6 |
| 750 Kwh/month | 17.84 | 20.73 | 25.29 | 28.63 | 60.5 |
| 1000 Kwh/month | 23.18 | 27.14 | 33.00 | 37.49 | 61.7 |
| Average of Eight Selected Utilities | | | | | |
| Commercial Service | | | | | |
| 6.0 kw/750 Kwh | 31.90 | 35.36 | 39.18 | 42.54 | 33.4 |
| 12.0 Kw/1,500 Kwh | 59.15 | 66.12 | 75.56 | 82.17 | 38.9 |
| 30.0 Kw/6,000 Kwh | 191.08 | 218.31 | 252.63 | 280.49 | 46.8 |
| 40.0 Kw/10,000 Kwh | 285.83 | 328.56 | 384.31 | 428.76 | 50.0 |

Source: Tables A1 through A10.

Table A12

SELECTED FINANCIAL INFORMATION AND FINANCIAL RATIOS FOR THE PERIOD 1974-1977

Central Illinois Public Service Co.

| Year | Price/ Share | Earn/ Share | P/E Ratio | Dividend Payout | Market/ Book |
|---|---|---|---|---|---|
| 1977 | $15.04 | $1.60 | 9.4 | 80.0% | 1.11 |
| 1976 | 14.26 | 1.47 | 9.7 | 85.7 | 1.08 |
| 1975 | 12.53 | 1.67 | 7.5 | 71.9 | 0.97 |
| 1974 | 11.84 | 1.48 | 8.0 | 81.0 | 0.93 |
| % Change | 27.02% | 0.08% | 17.5% | (1.23%) | 19.35% |

Source: The Value Line Investment Survey

Table A13

SELECTED FINANCIAL INFORMATION AND FINANCIAL RATIOS FOR THE PERIOD 1974-1977

Cleveland Electric Illuminating Co.

| Year | Price/ Share | Earn/ Share | P/E Ratio | Dividend Payout | Market/ Book |
|---|---|---|---|---|---|
| 1977 | $22.11 | $ 2.91 | 7.6 | 60.5% | 1.17 |
| 1976 | 19.75 | 2.38 | 8.3 | 71.8 | 1.14 |
| 1975 | 17.51 | 2.11 | 8.3 | 78.2 | 1.08 |
| 1974 | 17.39 | 2.45 | 7.1 | 65.3 | 1.13 |
| % Change | 27.14% | 18.78% | 7.04% | (7.35%) | 3.35% |

Source: The Value Line Investment Survey

Table A14

SELECTED FINANCIAL INFORMATION AND FINANCIAL RATIOS FOR THE PERIOD 1974-1977

Illinois Power Co.

| Year | Price/ Share | Earn/ Share | P/E Ratio | Dividend Payout | Market/ Book |
|---|---|---|---|---|---|
| 1977 | $26.53 | $2.68 | 9.9 | 82.8% | 1.26 |
| 1976 | 25.79 | 2.41 | 10.7 | 91.3 | 1.25 |
| 1975 | 23.31 | 2.71 | 8.6 | 81.2 | 1.16 |
| 1974 | 19.66 | 2.26 | 8.7 | 97.3 | 1.01 |
| % Change | 34.97% | 18.58% | 13.8% | (14.9%) | 24.75% |

Source: The Value Line Investment Survey

Table A15

SELECTED FINANCIAL INFORMATION AND FINANCIAL RATIOS FOR THE PERIOD 1974-1977

Indianapolis Power and Light Co.

| Year | Price/ Share | Earn/ Share | P/E Ratio | Dividend Payout | Market/ Book |
|---|---|---|---|---|---|
| 1977 | $24.42 | $ 3.44 | 7.1 | 56.1 | 1.14 |
| 1976 | 21.92 | 2.52 | 8.7 | 71.9 | 1.10 |
| 1975 | 19.35 | 2.36 | 8.2 | 77.1 | 1.03 |
| 1974 | 18.91 | 1.91 | 9.9 | 95.3 | 1.00 |
| % Change | 29.14% | 80.1% | (28.28%) | (41.13) | 14.0% |

Source: The Value Line Investment Survey

Table A16

SELECTED FINANCIAL INFORMATION AND FINANCIAL RATIOS FOR THE PERIOD 1974-1977

Iowa Power & Light Co.

| Year | Price/ Share | Earn/ Share | P/E Ratio | Dividend Payout | Market/ Book |
|---|---|---|---|---|---|
| 1977 | $26.06 | $3.14 | 8.3 | 69.1% | 1.09 |
| 1976 | 23.18 | 3.01 | 7.7 | 67.4 | 1.03 |
| 1975 | 20.03 | 3.18 | 6.3 | 59.1 | 0.89 |
| 1974 | 18.41 | 2.63 | 7.0 | 66.9 | 0.85 |
| % Change | 41.55% | 19.39% | 18.57% | 3.29% | 28.2% |

Source: The Value Line Investment Survey

Table A17

SELECTED FINANCIAL INFORMATION AND FINANCIAL RATIOS FOR THE PERIOD 1974-1977

Iowa Public Service Co.

| Year | Price/ Share | Earn/ Share | P/E Ratio | Dividend Ratio | Market/ Book |
|---|---|---|---|---|---|
| 1977 | $21.99 | $ 2.65 | 8.3 | 67.9% | 1.07 |
| 1976 | 19.54 | 2.22 | 8.8 | 76.1 | 1.00 |
| 1975 | 16.60 | 2.63 | 6.3 | 58.6 | 0.86 |
| 1974 | 16.07 | 2.06 | 7.8 | 72.8 | 0.82 |
| % Change | 36.84% | 28.64% | 6.41% | (6.73%) | 30.49% |

Source: The Value Line Investment Survey

Table A18

SELECTED FINANCIAL INFORMATION AND FINANCIAL RATIOS FOR THE PERIOD 1974-1977

Kansas Power & Light Co.

| Year | Price/ Share | Earn/ Share | P/E Ratio | Dividend Payout | Market/ Book |
|---|---|---|---|---|---|
| 1977 | $ 21.37 | $ 3.01 | 7.1 | 56.5 | 0.97 |
| 1976 | 19.11 | 2.73 | 7.0 | 58.6 | 0.97 |
| 1975 | 17.04 | 2.47 | 6.9 | 61.5 | 0.89 |
| 1974 | 17.20 | 2.00 | 8.6 | 76.0 | 0.91 |
| % Change | 24.24% | 50.5% | (17.44%) | (25.66%) | 6.59% |

Source: The Value Line Investment Survey

Table A19

SELECTED FINANCIAL INFORMATION AND FINANCIAL RATIOS FOR THE PERIOD 1974-1977

Northern Indiana Public Service Co.

| Year | Price/ Share | Earn/ Share | P/E Ratio | Dividend Payout | Market/ Book |
|---|---|---|---|---|---|
| 1977 | $18.95 | $ 2.06 | 9.2 | 69.9% | 1.04 |
| 1976 | 18.25 | 2.50 | 7.3 | 56.0 | 1.00 |
| 1975 | 16.20 | 2.16 | 7.5 | 62.9 | 0.93 |
| 1974 | 15.36 | 1.92 | 8.0 | 70.8 | 0.91 |
| % Change | 23.37% | 7.29% | 15.0% | (1.27%) | 14.28% |

Source: The Value Line Investment Survey

Table A20

SELECTED FINANCIAL INFORMATION AND FINANCIAL RATIOS FOR THE PERIOD 1974-1977

Public Service Company of Indiana

| Year | Price/ Share | Earn/ Share | P/E Ratio | Dividend Payout | Market/ Book |
|---|---|---|---|---|---|
| 1977 | $28.86 | $ 3.28 | 8.8 | 61.3% | 1.30 |
| 1976 | 27.39 | 3.01 | 9.1 | 62.8 | 1.35 |
| 1975 | 23.77 | 2.33 | 10.2 | 74.2 | 1.26 |
| 1974 | 21.00 | 2.53 | 8.3 | 56.6 | 1.17 |
| % Change | 37.43 | 29.6 | 6.02 | 8.3% | 11.11% |

Source: The Value Line Investment Survey