MASTER

Analysis Report

Electric Utilities in the 1970's—Financial Practices and Performance

December 1980

U.S. Department of Energy
Energy Information Administration
Assistant Administrator for Applied Analysis
Washington, D.C. 20461

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December 1980

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ABSTRACT

The report "Electric Utilities in the 1970's--Financial Practices and Performance" explains characteristics of financial factors that are controlled by regulatory bodies and which have a significant impact upon the financial condition of investor-owned electric utilities. Specifically, the report emphasizes matters affecting a utility's cost of service such as: the composition of operating costs; normalization versus flow-through accounting (particularly where depreciation and the investment tax credit are concerned); the rate base; and construction work in progress and the related allowance for funds used during construction. The report also reviews aggregate investor-owned electric utility financial data for the 1970-77 period. CWP

PREFACE

This report explains characteristics of financial factors that are controlled by regulatory bodies and which have a significant impact upon the financial status of investor owned electric utilities (IOUs).

The author wishes to thank all those who contributed their help. Overall direction and coordination was provided by John Mitrisin, Director, Financial & Industry Studies Division. Sherre Washington cheerfully typed many versions of this paper.

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EXECUTIVE SUMMARY

This report comments upon certain financial factors affecting investor-owned electric utilities (IOUs) that are controlled by regulatory bodies and which affect the individual utility's estimated cost of service. Since cost of service determination is the basic method of estimating the appropriate level of revenues for a utility, ultimately, it affects the price customers pay for electricity. The factors discussed are of considerable importance because, despite the fact that the electric utility industry has been operating in a generally deteriorating financial environment since the 1960's, it is anticipated that the electric utility industry will require significant funds for capital outlays over the intermediate term. The report also provides an overview of the financial performance of IOUs during the 1970-77 period.^{1/}

Specifically, the factors that the report concentrates on are: the composition of operating costs; implications of normalization versus flow-through accounting (with emphasis

^{1/} See Energy Information Administration, Annual Report to Congress, 1978, Volume Three, Washington, D.C., EIA, 1979. pp. 139-141.

on differences in the way in which depreciation and the investment tax credit can be handled); how the rate base affects estimated cost of service; and the treatment of construction work in progress (CWIP) and the related allowance for funds used during construction (AFDC). The report emphasizes that regulatory authorities have more than one choice as to how utilities operating under their jurisdiction can treat an individual factor that is included in determining cost of service. Since the method chosen affects the utility's revenues, profitability, and cash flow, it becomes obvious that regulatory bodies can have a significant impact upon the financial well-being of the individual utility and the industry as a whole. This well-being is important because it is expected that the electric utility industry will require considerable funds over the intermediate term.

The report also points out that, although a regulatory body may treat utilities under its jurisdiction in a consistent manner, other regulatory bodies may treat the utilities they regulate in different ways. Therefore, the regulatory environment of the electric utility industry results in inconsistent methods of determining cost of service to customers and in reporting financial results. It also becomes apparent that in evaluating the financial status of a utility, the potential for erroneous conclusions exists if emphasis is placed on the way in which a

regulatory authority requires one or two specific cost of service elements to be treated while deemphasizing other elements. It is possible that the regulatory authority may use a conservative treatment of one element while providing an offsetting liberal treatment of another.

The report also reviews financial data for the investor-owned segment of the electric utility industry. A table is provided showing aggregate source and use of funds data for the 1970-77 period while another table details the composition of funds from operations for the same time span.

The aggregate Source and Use of Funds statement illustrates that significant changes have taken place in the types of financing used by IOUs since 1970 and that, with the exception of 1975, annual capital expenditures have increased steadily.

A separate schedule shows the effect of the financing shifts upon the aggregate capitalization of IOUs. An analysis of the breakdown of funds from operations for 1970-77 indicates that in 1977 net income and depreciation, depletion and amortization constituted the largest proportion of funds from operations, as in 1970, but the proportions were significantly smaller in 1977 than in 1970. Deferred income taxes and investment tax credit adjustments have

increased in absolute and relative size since 1970.

The table also reveals that the "Allowance for Funds Used During Construction" (AFDC) had risen to 28 percent of net income in 1977 versus 17 percent in 1970, which tends to support those who claim the quality of utility earnings has been declining.

1. OVERVIEW

Historical Perspective

During the 1970's, the domestic electric utility industry has operated in an environment considerably different from that of the relatively stable and favorable conditions of the 1960's. Consequently, in the 1970's the financial wellbeing of this industry has become a major concern.

For the largest segment of the industry, investor-owned utilities (IOUs),^{1/} electric operating revenues rose 197 percent from 1970 through 1977, while electric operating expenses increased 217 percent.^{2/} This is in contrast to the immediately preceding period. Electric operating revenues rose 65 percent during the seven year period from 1963 through 1970, while

^{1/} The domestic electric utility industry is composed of a privately owned sector, referred to as investor-owned utilities (IOUs), and a non-investor segment consisting of organizations owned either by municipalities, the Federal Government or cooperatives. The IOU sector consists of over 200 companies and accounts for about 80 percent of total U.S. electric generating capacity. The non-IOU sector, which accounts for the remaining 20 percent of capacity, consists of approximately 3,500 firms. In discussing the financial status of electric utilities, attention will be limited to the IOU sector. For additional information see U.S. Department of Energy, Energy Information Administration, The Feasibility of Financing Domestic Energy Development During 1978-1984, by Suraj Kanhouwa, Analysis Report, DOE/EIA-0181/2, May 1979, p. 49.

^{2/} U.S. Department of Energy (formerly Federal Power Commission), Statistics of Privately Owned Electric Utilities in the United States, (Washington, D.C., 1977 ed.), p. 34.

electric operating expenses rose only 37 percent.^{3/} The average cost of both the long- and short-term debt of IOUs has increased steadily over the past decade--from 4.17 percent in 1968 to 6.99 percent in 1977.^{4/} Since considerable IOU debt is coming due during the 1978-87 period, much of which was issued at four percent or less, average interest rates on total debt will rise as new debt replaces old.^{5/} Also, interest coverage ratios on IOU long-term debt have decreased steadily--from 3.7 in 1965 to 2.4 in 1977.^{6/} In addition, price/earning ratios of certain IOU common stocks (which ranged from 13.94 to 21.89 times earnings, on average, during the 1960's) sold at an average of only 8.30 times earnings in 1977, after having sold as low as 7.38 times earnings in 1975.^{7/} In many cases, utility stocks have sold below book values in the 1970's and a good argument can be made that although utility earnings have increased, their quality has decreased.

Adding to the problem is that IOUs have been having difficulty in predicting demand in recent years. This is extremely important in any highly capital intensive

industry since overexpansion of facilities can result
3/ U.S. Dept. of Energy (formerly Federal Power Commission),
Statistics of Privately Owned Electric Utilities in the
United States, 1974 ed.), p. XXV, 1971 ed. pp. XXIV, XXV.

4/ Ibid., 1977 ed., p. 9.

5/ Ibid., 1977 ed., p. 9.

6/ Ibid., 1977 ed., p. 36; 1974 ed. p. XXIX.

7/ Suraj Kanhouwa Op. cit., p. 72 (based on statistics
of Standard & Poor's).

in high per unit costs of electricity as fixed charges for depreciation are spread over lower than anticipated output. On the other hand, insufficient capacity can result in inadequate service to customers. Nonetheless, the electric utility industry will likely require significant funds over the intermediate term. The Department of Energy has estimated that during the January 1, 1979 - December 31, 1990 period, capital expenditures for the electric utility industry will range from \$276 billion to \$327 billion (in 1978 dollars)^{8/}. Bankers Trust Company has forecasted that for the shorter 1978-1982 period, capital requirements of the electric utility industry will amount to \$166 billion (in current dollars)^{9/}. In addition, electric utilities have encountered uncertainty about the availability of fuel supplies, increasing costs of new capacity and time lags in passing along the increased costs that are inherent in the regulatory process.^{10/}

^{8/} U.S. Department of Energy, Energy Information Administration, Annual Report to Congress, 1978 edition, Volume III, p. 130.

^{9/} Energy Group, Bankers Trust Company, U.S. Energy and Capital, A Forecast, 1978-1982, 1978, p. 17.

^{10/} Statistics and information relating to many of these issues can be found in various issues of Statistics of Privately Owned Electric Utilities in the United States, Classes A and B Companies prepared annually by the U.S. Department of Energy, and the 1976 edition of The National Power Survey, "The Adequacy of Future Electric Supply: Problems and Policies", prepared by the Federal Power Commission and the Department of Energy's Analysis Report referred to in footnote 1, "The Feasibility of Financing Domestic Energy Development During 1978-1984", by Suraj Kanhouwa.

Financially Related Regulatory Matters

Electric utilities are a regulated industry. State public utility commissions (PUCs) and, where interstate sales of electricity are involved, the Federal Energy Regulatory Commission establish policies and procedures concerning specific electric utility financial matters, including the establishment of rates that consumers pay for electricity. Thus, they exert significant control over the revenues and financial condition of individual utilities.

Under typical ratemaking procedures PUCs estimate appropriate total revenue requirements for each individual utility and then establish rates for various classes of customers that are intended to yield the estimated revenue requirements.^{11/} The basic revenue estimating procedure is the cost of service (COS) method.

11/ Sources consulted for background on ratemaking and financial issues in this work and to which the reader may wish to refer for more details include: Paul J. Garfield and Wallace Lovejoy, Public Utility Economics, Englewood Cliffs, N.J., Prentice-Hall, 1964; Haskins & Sells, Public Utilities Manual (1977 or later); Price Waterhouse & Co., 1977 Survey of Financial Reporting and Accounting Developments in the Public Utility Industry; Summer N. Levine, editor, Financial Analysts Handbook, II "Dow Jones-Irwin, Inc., Ill., 1975, Chapter 30 "Utilities" by Kenneth Hollister; Temple, Barker & Sloan, Inc., draft of report for the Department of Energy, Financing Issues in the Electric Utility Industry, Lexington, Mass.; and Daniel White, "Financing Electric Utility Investment Requirements", Public Utility Fortnightly, January 18, 1979, pp. 27-32.

Under COS, total revenues should: cover the utility's appropriate operating expenses, depreciation and amortization, and taxes; and provide a fair and reasonable return on the rate base so that the company will be able to pay interest and dividends, retain a portion of their earnings which over time, will expand the equity base, and attract capital. The operating expenses, depreciation and amortization and some taxes are considered to be normal operating expenses of doing business. They are termed "above the line" items because, in the statement of Income and Retained Earnings, they appear above the net operating income line. Generally, for each above the line expense category, a calculation is made of the amount to be included in COS. Therefore, the sum of all above the line costs is part of COS. Items considered to be of a nonoperating nature such as interest income, interest expense and dividends are referred to as "below the line" items. The amount of COS that will cover below the line items is determined by calculating a return on the rate base; the rate base is composed mainly of a utility's property plant and equipment.

Cost of service, therefore, is composed of two elements: itemized "above the line" expenses and a return on the rate base that will cover "below the line" items. It is worthwhile to note though that there is a lack of consistency among PUCs as to the way in which they calculate and treat various cost of service elements.

Generally, there are few problems in determining the types of operating expenses included in COS, although there are questions as to the proper time period used to estimate them. Depreciation allows a firm to recover its investment in depreciable fixed assets by including a portion of the basis of those investments as an expense of doing business each period. However, the depreciation method used for taxes versus those used for ratemaking often differ thereby resulting in deferred taxes. In a typical situation this means that higher tax payments which would have been made if the book depreciation method had been used for tax purposes, will be deferred to a later date. Whether deferred tax expense should be included as a current cost of doing business for ratemaking purposes is a prominent question that is referred to as the "normalization" issue.

Specific issues related to the rate base deal with the method of valuing rate base assets and whether construction work in progress (CWIP) should be included in the base. A derivation of the CWIP issue is whether an allowance for funds used during construction (AFDC), which is a nonoperating, noncash income item, adversely affects the quality of reported earnings.

2. FINANCIALLY RELATED ISSUES

Introduction

Not all financially oriented regulatory and non-regulatory issues are dealt with in this study. For example, the time lag that IOUs encounter when trying to pass on rising fuel costs to customers, the relationship of utility stock prices to book value, interest rate trends, reductions in the quality ratings of some utilities' securities and the impact upon generating capacity are not treated in detail here. Emphasis is directed at factors that are related to cost of service calculations.

Operating Expenses Included in Cost of Service

Little controversy exists over the types of costs included as operating expenses in determining cost of service. They include mainly costs of fuel, maintenance, distribution and purchase power. However, opinions differ as to what is the appropriate period upon which to calculate these expenses. Whatever period is selected, it should have some valid relationship to the period used to determine the rate base. Operating costs could be based on a compilation of average historical data or an estimate of future costs. If operating expense requirements are underestimated by a PUC, then

12/ Haskins & Sells, Public Utilities Manual (1977 or later), p. 13.

revenues will be inadequate to cover actual operating expenses and this will have an adverse impact upon earnings and cash flow.

Normalization and Flow Through Accounting

The normalization issue is whether a utility should be allowed to include in cost of service the income tax expense for which it incurs an actual current liability to the Internal Revenue Service (IRS) or that tax expense plus or minus a deferred tax adjustment. This deferred tax adjustment, or normalization of the tax expense, comes about because taxpayers typically account for certain transactions one way for tax purposes and another way for book, or financial, reporting purposes. When normalization is used for ratemaking purposes, total tax expense will exceed the IRS tax expense during the early life of an asset. In later years, the situation will be reversed, and the tax expense for ratemaking purposes will be lower than the IRS tax expense. Thus, if a PUC allows cost of service to include normalized taxes, in early periods the rates charged current customers will be higher than if only the current IRS tax expense is allowed to "flow-through" to these consumers in the form of lower current rates for electricity. Therefore, normalization of income tax expense results in a larger cash inflow to a utility during the early life of assets than does the "flow-through" method of treating income tax expense.

Two typical situations where utilities treat an accounting entry one way for financial, or book, purposes even though the same item is treated entirely differently for tax purposes (thereby providing the potential for normalization of tax expense) are depreciation and the investment tax credit.^{13/}

Depreciation. Depreciation allows a firm to recover its capital expenditures for fixed assets as an expense of doing business over time. The depreciation practice that is almost always used for ratemaking purposes is the straight line method which spreads the depreciation expense evenly over the life of the asset. For tax purposes, it is common to use various accelerated methods of depreciation which depreciate a greater amount during the early life of an asset than the straight line method. As a result, for tax purposes, in the early life of an asset accelerated depreciation results in a lower income before taxes than if straight line depreciation had been used. The difference in accelerated and straight line depreciation during a period

^{13/} More detailed information on this subject is contained in an informal paper "Technical Analyses of the Phenomenon Referred to as Public Utility Phantom Taxes", by Stephen Skjei, U.S. Department of Energy, Office of Policy and Evaluation, Utilities Division, December 21, 1978. Also, refer to appropriate sections of the Internal Revenue Code, specifically Sections 46(f), (1) and (2) and related Treasury Regulations.

multiplied by the corporate tax rate is the amount of deferred taxes. For ratemaking, these deferred taxes will be added to the actual IRS tax expense for the year and the total will be used in calculating cost of service; an amount equal to the deferred tax expense will be added to a cumulative deferred tax account that appears in the Balance Sheet. In later periods, accelerated depreciation results in a higher income before taxes than the straight line method. Over the entire life of the asset, total depreciation will be approximately the same regardless of whether straight line depreciation or an accelerated method is used.^{14/}

By using accelerated depreciation for tax purposes, actual taxes to be paid during the early life of an asset will be lower than if the straight line procedure were used. This enables an IOU to benefit from the time value of the additional funds it has during the early periods due to paying lower taxes.

As stated previously, straight line depreciation is typically used for ratemaking; so in the early life of a fixed asset, the depreciated basis of fixed assets (i.e., original basis of the assets less accumulated depreciation on those assets)

^{14/} There will be some difference in total depreciation under straight line and accelerated depreciation because the straight line method deducts estimated salvage value from the cost of the asset to determine its depreciable basis whereas accelerated depreciation does not.

on the Balance Sheet will be higher than if accelerated depreciation were used for ratemaking purposes. Since fixed assets compose the vast majority of the rate base, during the early life of a fixed asset, the rate base will be higher than if accelerated depreciation were used on the assets for ratemaking reasons. This holds true even though it is common for PUCs to require IOUs to calculate the rate base by deducting from the depreciated basis of the fixed asset account the cumulative amount of deferred taxes that are in the Balance Sheet due to depreciation.

These points can be illustrated by making a few assumptions. If first-year depreciation on a fixed asset was \$10 for book, or ratemaking, purposes (due to using the straight line method) and \$20 for income tax purposes (due to using accelerated depreciation), then income before taxes for ratemaking purposes would be \$10 higher than for tax purposes -- assuming all revenues and other pre-tax expenses were the same in both cases. If it is further assumed that a tax rate of 50 percent was applied to income before taxes, the current income tax expense (i.e., the tax expense legally due to the Internal Revenue Service) would be \$5 lower than if the tax rate had been applied to the higher income before taxes for ratemaking purposes. Therefore, by using accelerated depreciation for tax purposes instead of straight line depreciation, \$5 of income tax expense has been deferred.

This \$5 has not been avoided since eventually depreciation on the fixed asset will be greater under the straight line method than under the accelerated method. The way of recognizing this situation for ratemaking purposes is to establish on the books a deferred income tax expense account of \$5; this will be added to the current income tax expense, which is also on the books, to produce an effective tax rate of 50 percent based on income before taxes for ratemaking purposes. The other portion of this entry is to credit \$5 to a deferred tax account in the Balance Sheet.

The results of these assumptions is that for tax purposes the only income tax expense would be the current portion actually due to the Internal Revenue Service -- assume \$15; for ratemaking purposes the income tax expense would be the \$15 current portion plus the \$5 deferred tax expense, or a total expense of \$20. If it is assumed that the fixed asset cost \$100, its depreciated basis for tax purposes would be \$80 (i.e., \$100 less \$20 of cumulative accelerated depreciation). The depreciated basis of the fixed asset for ratemaking purposes would be \$90 (i.e., \$100 less \$10 of cumulative straight line depreciation). Subtracting the \$5 of deferred taxes in the Balance Sheet from the \$90 leaves \$85 to be used as the rate base in this example, which is higher than the \$80 depreciated basis of the fixed asset for tax purposes due to using accelerated depreciation. It would be highly unusual for accelerated depreciation to be used for ratemaking purposes.

As mentioned previously, in the later life of a fixed asset, annual depreciation expense will be less using the accelerated procedure than by using straight line. However, these comments refer to a single depreciable asset. As long as an IOU's base amount on all of its depreciable assets is increasing or is stable from one period to the next, total accelerated depreciation on all assets may exceed straight line depreciation, even though the reverse may be true for certain individual assets contained within the total asset base.

Investment Tax Credit. The investment tax credit (ITC) allows a taxpayer to reduce his federal income tax expense by a certain percentage of his "qualified investment" in certain new depreciable equipment placed in service during the period.^{15/} The percentage is subject to certain limitations but, in general, may not exceed 10% of the qualified investment. A credit, of course, reduces income taxes dollar for dollar, whereas an expense deduction, such as depreciation, reduces taxes by the product resulting from multiplying the

^{15/} The term "qualified investment" refers to that portion of the investment in the property to which the tax credit may be applied. The amount of qualified investment is less than 100 percent of the basis of the property if it has a useful life of less than seven years. The amount of the credit is generally 10 percent of the qualified investment but, under certain circumstances an 11 percent rate may be used. For further details see: Commerce Clearing House, Inc., United States Master Tax Guide, 1979, Chicago, Ill., Sec. 1178-1184, pp. 447-452. In some situations, the investment tax credit may be taken as the asset is being constructed (i.e., before it is placed in service).

depreciation expense by the corporate tax rate. For rate-making purposes, an IOU is permitted to immediately flow through (i.e., pass on) the entire investment tax credit to customers only if prior to 1969 it used flow-through accounting for ratemaking when using accelerated depreciation.

If the flow-through method (or as it is sometimes referred to, "immediate flow-through") is used for ratemaking, income tax expense will be reduced by the entire ITC during the period in which the investment is put in service; this particular factor will result in lower initial cost of service than if a normalization procedure were used. For ratemaking, depreciation will be based on the original cost of the asset, not original cost less the ITC, and the rate base will be original cost less accumulated depreciation. If, instead, a normalization procedure is used, customers will be affected differently. Two normalization methods are used. They are referred to as the Ratable Flow-Through Method (RFT) and the Rate Base Reduction Method (RBR).^{16/}

Under RFT, the tax credit reduces tax expense evenly over the life of the asset for ratemaking purposes. Thus, if an IOU received a \$10 million credit on assets with an average

^{16/} The term "Rate Base Reduction" is used in the previously mentioned (see footnote 13) informal paper on phantom taxes where the issue is discussed in more detail. It is not an official Federal Energy Regulatory Commission term. The term "Ratable Flow-Through" is also referred to as "Rateable Flow-Through."

ten year life, for ratemaking purposes the above the line income tax expense would be reduced by \$1 million in each of the ten years. In contrast, if the immediate flow-through method were used for ratemaking, which is not a normalization procedure, tax expense would be reduced by the entire \$10 million in the first year and there would be no credits in future years due to these assets. For ratemaking under RFT, depreciation will be based on the original cost of the asset (as with the immediate flow-through method); the rate base will not be reduced by the cumulative amount of deferred taxes in the Balance Sheet due to the ITC (unlike the procedure followed for depreciation normalization).

If RBR is used, the investment tax credit reduces expenses over the life of the asset for ratemaking purposes, as with RFT. However, unlike RFT, RBR treats the annual ITC (in the previous example, \$1.0 million) as a below the line item. This means that with RBR, the above the line federal income tax expense, which is included with other specific operating costs in determining COS (see pages 4 and 5), will be higher than with RFT. On the other hand, with RBR the below the line costs, which are recovered by the return on the rate base (discussed subsequently) portion of COS, will be lower than with RFT. Therefore, the method of normalization used for investment tax credits will produce the same amount of ITC. However, the location of the ITC in the Statement of Income and Retained Earnings will differ depending on the method of normalization used. Since different

methodologies are used by PUCs in covering above the line and below the line COS items, the location of the ITC will affect the rate charged to customers.

For ratemaking with RBR, depreciation is based on the original cost of the asset (i.e., not the original cost less the ITC), as with RFT. However (unlike RFT), with RBR the cumulative amount of deferred taxes in the Balance Sheet due to ITC is deducted from the depreciated basis of the fixed asset account in determining the rate base. The cumulative deferred Balance Sheet account is reduced ratably each period over the life of the asset.^{17/} Consequently, each period under RBR, the rate base increases due to this procedure. It is not the purpose of this paper to treat in more detail specific accounts or accounting entries related

17/ For a further discussion of the complicated subject of what is "ratable" the reader is referred to: Commerce Clearing House, Inc., Standard Federal Tax Reporter, 1979, Vol. 1 (Treasury Regulations and CCH Explanations), Reg. 1.46-6(g), p. 11, 187. In part, this portion of the Standard Federal Tax Reporter States: "What is "ratable" is determined by considering the period of time actually used in computing the taxpayer's regulated depreciation expense for the property for which a credit is allowed. "Regulated depreciation expense" is the depreciation expense for the property used by a regulatory body for purposes of establishing the taxpayer's cost of service for ratemaking purposes. Such period of time shall be expressed in units of years (or shorter period), units of production, or machine hours and shall be determined in accordance with the individual useful life system or composite (or other group asset) account system actually used in computing the taxpayer's regulated depreciation expense. A method of restoring, or reducing, is ratable if the amount to be restored to rate base, or to reduce cost of service (as the case may be), is allocated ratably in proportion to the number of such units."

to the ITC. Furthermore, details on appropriate accounting and tax treatment of RFT and RBR are discussed in less than clear language of Sections 46(f) (1) and (2) of the Internal Revenue Code.

In summary, three treatments of the ITC have been discussed. The flow-through method reduces income tax expense by the entire amount of the credit in the initial period of service. Thus, current customers benefit immediately from reduced utility rates which reflect the utilization of the entire credit. Under the flow-through method, depreciation will be based on the total cost of the fixed asset (not original cost less ITC) and the rate base will be original cost of the fixed assets less depreciation.

Two normalization procedures were discussed -- RFT and RBR. In both cases, the reduction in costs due to ITC is spread over the life of the asset (although RFT reduces above the line expenses whereas RBR reduces below the line expenses) and depreciation is based on the original cost of the asset. Therefore, under normalization, rates that utility customers pay will not immediately reflect the entire benefit of the credit; in other words, future, as well as current, customers will benefit from the credit.

The determination of the rate base under RFT and RBR differs. Under RFT, the rate base will be the original cost of the fixed asset (i.e., not original cost less ITC) less accumulated depreciation. With RBR, the rate base will be calculated by taking the net basis of the fixed assets (i.e., original cost less accumulated depreciation, as with RFT) and then (unlike RFT) deducting the balance of the deferred tax account due to ITC that is in the Balance Sheet. This deferred tax account is reduced ratably over the life of the asset but because it is deducted from the rate base under RBR, the RFT method produces a higher rate base than the RBR method. Obviously, if the same percentage was applied to the rate base under both the RBR and RFT procedures, a utility would obtain lower revenues under RBR -- due to this one calculation. But this does not necessarily mean that a utility would receive lower total revenues if it used RBR versus RFT.

The overall revenues a utility receives is dependent not only on the rate base, they also depend on the percentage applied to the rate base and the amount of above and below the line expenses -- and above and below the line expenses are not equal under the two methods. As mentioned previously, an estimate is made of each above the line expense item and the sum of all such items is part of COS.^{18/} The amount of

^{18/} See pages 4 and 5.

COS that will cover estimated below the line costs and other items is calculated by applying a percentage to the rate base (discussed subsequently). Utility rates will then be set at levels that are expected to yield total revenues that will cover both COS elements. If a company uses RBR versus RFT for a specific transaction RFT could result in higher overall revenues. However, given the exact same circumstances and then changing only one factor, such as the percentage applied to the rate base, it is possible that RBR would result in higher overall revenues than RFT.

Rate Base Composition

As mentioned previously, in addition to covering above the line expenses, the cost of service method provides for a return on the rate base so that the utility will be able to cover below the line expenses such as interest, pay dividends, retain some of its earnings and attract capital. Normally, 95 percent or more of a company's rate base is composed of the utility's property, plant and equipment in service less ^{19/} the accumulated reserve for depreciation and amortization.

Whether plant and equipment is in service depends on the individual PUC's interpretation of the regulatory concept of "used and useful." Assets may be "useful" to a utility and thus be included in the rate base even though they may

^{19/} Haskins & Sells, Public Utilities Manual (1977 or later), p. 15.

not actually be in current "use" (e.g., land held for future use). The preponderant practice is to value the rate base on original cost as opposed to a reproduction cost or a fair market value. Once the base is established, it is multiplied by a percentage that generally represents the weighted cost of capital; the product is included as part of the cost of service. The percentage that the base is multiplied by varies from utility to utility. It depends on each utility's amount of debt and equity, interest rate on debt, preferred dividends, a rate of return on common equity that the PUC determines, and the rate setting philosophy of the individual PUC. All other things being equal, the higher the rate applied to the rate base, the higher will be the revenues, gross cash inflows, and reported earnings of the utility.

Construction Work in Progress and the Allowance for Funds Used During Construction

The issue of whether to include the cost of construction work in progress (CWIP) in the rate base has two components. One question is whether current customers should pay the financing costs of facilities not yet in service and the other is whether the exclusion of CWIP from the rate base adversely affects the quality of earnings by interjecting significant noncash income into the Statement of Income and Retained Earnings.

The issue is essentially this; if CWIP is included in the asset base, the utility will receive actual cash revenues from its current customers to help cover associated financing costs of the CWIP. If CWIP is excluded from the rate base, there will be no cash inflow from current customers to cover these financing costs; instead, to cover financing costs, an imputed noncash income item will be included as nonoperating (i.e., below the line) income in the current income statement and a like amount will be added to the CWIP account. The above assumes that all other factors, such as the percentage applied to the rate base, are equal. It would be possible for one PUC to exclude CWIP from the rate base but apply a high percentage to it, thereby producing the same result as a different PUC that included CWIP in the base while applying a lower percentage.

The dominant view among PUCs is that only assets that are in actual use, or that are just about to be put into actual use, should be included in the rate base. By excluding CWIP from the rate base, current customers do not have to pay for the financing costs of debt or stock used to raise funds for the construction. Of course, once CWIP is considered to be completed and is included in the rate base, the cost of service to customers will include both the depreciation charges and the financing cost.

During the construction period though, if CWIP is not included in the rate base, the utility will still pay the costs of financing the construction even though the facilities being constructed do not generate revenues to offset the financing costs, some of which reduce earnings. Therefore, when CWIP is not in the rate base, PUCs allow each utility to calculate its imputed cost of financing the CWIP and include the amount as noncash, nonoperating income while a like amount is added to the CWIP account in the balance sheet.^{20/} The noncash amount treated as nonoperating income is typically referred to as "Allowance for Funds Used During Construction" (AFDC).^{21/} As a result of this practice, as the CWIP asset account increases, so will annual AFDC, assuming all other factors, such as the rate to calculate imputed costs, remain constant.

Essentially, AFDC is a variation of the treatment of "interest during construction" that is applied to non-utility firms. The theory is that while a facility is being constructed it is not able to generate revenues to cover the costs of the funds used to finance the construction. Therefore, it is

^{20/} The CWIP account is multiplied by a percentage determined by each PUC (which may or may not be the same rate applied to the rate base) to determine the amount of AFDC.

^{21/} Effective 1977, AFDC is subdivided into two parts known as "Allowance for Other Funds Used During construction" and "Allowance for Borrowed Funds Used During Construction".

considered inappropriate to reduce earnings by the interest costs of the associated debt until the facility has been completed (i.e., presumably is able to generate revenues). Since, in practice, it is often impossible to associate actual debt with a specific facility, the interest expense may be imputed. With a utility, all interest costs reduce reported earnings but AFDC mitigates the impact on earnings. However, although AFDC increases earnings, it does not increase cash inflow. Therefore, it can be argued that since AFDC earnings are noncash earnings, they are of inferior quality to the cash earnings derived when CWIP is included in the rate base. Furthermore, it can be argued that the quality of earnings is in a deteriorating trend for those companies that are not allowed to include CWIP in their asset base because noncash AFDC has been increasing significantly in recent years as a proportion of total net income. Specifically, AFDC was 28.2 percent of net income in 1977, up from 17.3 percent in 1970 and only 3.6 percent in 1965.^{22/} As for CWIP, at the end of 1977 it composed 23.6 percent of total electric utility plant (after deducting the accumulated reserve for depreciation and amortization)

^{22/} U.S. Department of Energy (formerly Federal Power Commission), Op. Cit., Statistics of Privately Owned Electric Utilities in the United States, 1977 ed., p. 12; 1974 ed., p. IX.

compared to 14.3 percent at the end of 1970 and 5.3 percent
at the end of 1965.^{23/}

It has been pointed out that as the proportion of a utility's reported earnings received in cash decreases, the quality of its reported and perceived earnings decreases and investors take this reduced earnings quality into account when evaluating the appropriate market value of the firm's common stock.

Thus, as the quality of reported earnings decreases, so does market value of the stock. Also, the reduction in current cash inflow due to using AFDC (as opposed to charging current customers higher rates) adversely affects interest coverage ratios, results in reduced bond ratings, and causes utilities to use higher cost financing.^{24/}

Summary

Several financially-related issues have been commented upon in this section. They include: types of expenses to be

^{23/} U.S. Department of Energy (formerly Federal Power Commission), Statistics of Privately Owned Electric Utilities in the United States, Washington, D.C., 1977 ed., p. 30; 1965 ed., pp. XIII, XVII.

^{24/} Federal Energy Administration. Written statement regarding Federal Power Commission Docket #RM 75-13, Amendments to Uniform Systems of Accounts for Public Utilities and Licenses and for Natural Gas Companies (Classes A, B, C and D) and to Regulations Under the Federal Power Act and the Natural Gas Act to Provide for Inclusion of Construction Work in Progress in Rate Base, by Roger Feldman, Deputy Assistant Administrator for Finance and Environment, Energy Resource Development, Washington, D.C. 1976, pp. 6-8.

included in COS; normalization and flow-through accounting for depreciation and the ITC; the composition of the rate base; the rate applied to the rate base; construction work in progress; and AFDC.

It becomes apparent that in evaluating the financial status of a utility there is potential for drawing erroneous conclusions if one focuses attention on only one of these factors. It is possible that a PUC may treat one factor in a manner that is relatively favorable from the utility customers' standpoint while treating another factor in a manner that is relatively favorable to the utility. Furthermore, there is a lack of consistency among PUCs as to how they treat various factors affecting cost of service.

25/ For additional commentary about the regulation of utilities which deals with, and expands upon, some of the matters covered in this chapter, the reader is referred to: U.S. Department of Energy, Energy Information Administration, State Regulation of Electric and Gas Utilities, by Martin Taschdjian and James Hewlett, Energy Policy Study, Vol. 4, DOE/EIA-0201/4.

3. HISTORICAL FINANCIAL DATA

Introduction

This chapter contains three tables which illustrate financial trends of investor owned-utilities on an aggregate basis:

Table 1, Sources and Uses of Funds; Table 2, composition of capitalization; and Table 3, the composition of internally generated funds. The data for the tables have been taken

from various editions of the U.S. Department of Energy annual publication, Statistics of Privately-owned Electric Utilities in the United States, Classes A and B Companies

(formerly published by the Federal Power Commission) which contains very comprehensive financial information.^{26/} In addition, its validity tends to be verified by comparing

^{26/} Still, it must be recognized that the DOE data on changes in financial position (including the composition of internally generated funds in Table 3) have certain limitations: (1) they were not compiled prior to 1970, so very long term trends are not available; (2) the utilities are not governed by consistent regulatory practices, hence all data are not prepared consistently; (3) for reporting purposes to DOE, utilities do not always classify data (as opposed to calculating it) consistently which required making some adjustments to source data in preparing Table 3; and, (4) the DOE format for the statement in Table 1 does not show the annual changes in working capital so it has been necessary to calculate changes in working capital from Balance Sheets. Despite the limitations, these data appear to be the most detailed available on the subject.

specific line items with similar items contained in a publication of the Edison Electric Institute.^{27/}

Sources and Uses of Funds Overview

Table 1 indicates that funds from IOU operations increased from \$5.6 billion to \$14.3 billion, or 155 percent, during the 1970-1977 period. Even so, it was necessary for IOUs to rely heavily upon outside, or "new money", sources which rose from \$8.2 billion in 1970 to \$16.0 billion in 1977. Extensive use of new money was necessary to meet very large annual expenditures for property, plant and equipment and to retire or refinance significant amounts of debt. Dividend payments during the eight year span increased from \$2.5 billion to \$6.1 billion. Although the absolute dollar amount increased significantly, as a percentage of funds from operations, dividends ranged from 46 percent to 42 percent. They were at the lower end of this range in the 1975-77 period when IOUs experienced large increases

^{27/} Specifically, reference is made to the Edison Electric Institute (EEI) annual publication Statistical Year Book of the Electric Utility Industry which aggregates financial information of the investor, or privately owned, sector of the industry. A difference in the EEI and the DOE publications is that EEI excludes Alaska and Hawaii whereas DOE includes all 50 states. Still, a comparison of the net income and capital expenditure data on p. 61, Table 52S, and p. 59, Table 50S of the 1977 edition of the EEI publication with similar data in Tables 1 and 3 shows that they are very close. Unfortunately, the EEI does not publish an aggregate statement of changes in financial position whereas DOE does.

Table 1. Sources and Uses of Funds for Classes A and B Investor-Owned Electric Utilities, 1970-1977 (Million Current Dollars)

	1970	1971	1972	1973	1974	1975	1976	1977
Sources of Funds:								
From Operations	5,603	6,353	7,269	8,021	8,648	10,543	12,825	14,337
Outside Sources (new money):								
Long-Term Debt	5,597	5,443	5,113	5,411	8,473	7,885	6,902	7,879
Preferred Stock	1,145	1,750	2,292	1,713	1,829	2,045	1,673	1,965
Common Stock	1,363	1,762	2,181	2,376	1,774	3,111	3,626	3,880
Net Increase in Short-Term Debt	-	133	-	1,687	2,955	754	768	1,222
Other (net)	142	212	532	490	964	869	955	1,077
Total--New Money Sources	3,247	9,300	10,118	11,682	15,995	14,664	13,924	16,023
Other Sources (net)	663	1,084	819	1,350	987	1,904	1,876	2,027
Total	14,513	16,737	18,206	21,053	25,630	27,111	28,625	32,387
Application of Funds:								
Construction and Plant Expenditures (includes land) ^a	10,481	12,274	13,469	14,872	16,370	15,249	17,331	20,148
Dividends	2,501	2,824	3,188	3,639	4,011	4,616	5,403	6,087
Retirement of Securities & Short-Term Debt:								
Long-Term Debt	593	650	629	677	1,231	2,005	1,597	2,477
Preferred Stock	3	4	114	13	8	15	26	165
Common Stock	1	2	2	(47)	12	5	7	6
Net Decrease in Short-Term Debt	159	-	-	758	369	3,218	1,685	1,208
Other (net)	122	143	39	141	436	611	586	210
Total Retirements	878	799	784	1,542	2,056	5,854	3,901	4,066
Other Uses (net)	578	702	398	1,241	606	586	1,105	1,069
Total	14,438	16,599	17,839	21,294	23,043	26,305	27,740	31,370
Increase/(decrease) in Working Capital, (excluding short-term debt)	75	138	367	(241)	2,587	806	885	1,017

a/ Excludes Allowance for Funds Used During Construction.

Source: U.S. Department of Energy (formerly Federal Power Commission) Statistics of Privately Owned Utilities in the United States, Classes A and B Companies, Washington, D.C. various issues.

in funds from operations. The net impact of "Other Sources (Net)" and "Other Uses (Net)", which includes sales of noncurrent assets and investments and advances to subsidiaries, was relatively small.

A closer look at fund sources on Table 1 indicates that from 1970 through 1973, funds from operations accounted for 38-40 percent of total fund sources, but in 1974 the percentage dropped to 34 percent. Reasons for this sharp decline were an extraordinarily large increase in fuel costs that resulted from actions of OPEC nations, time lags in passing on higher costs to customers due to inherent delays in the regulatory process and an absolute decline in electricity consumption. These factors helped to hold the annual increase in funds from operations to \$627 million, while 1974 construction expenditures were rising \$1.5 billion from the 1973 level.

In 1975, funds from operations composed 39 percent of total funds and then rose further, to 45 percent in 1976. In 1977, funds from operations remained at approximately the 1976 proportion. Contributing to the increased significance of funds from operations during the 1975-77 period were sharply higher earnings due to more favorable rates, increases in electricity consumption, and benefits of the higher

statutory investment tax credit due to enactment of the "Tax Reduction Act of 1975". An additional factor was the decrease in construction expenditures in 1975, which reduced fund requirements. This was due partly to cutbacks in expansion plans by some utilities as a result of uncertainty over future electricity demand and high financing costs. As industry conditions improved in 1976 and 1977 construction expenditures rose again but funds required for the retirement of securities dropped below the 1975 level. Increases in construction expenditures in recent years have been due not only to the addition of capacity but also because the cost of adding the capacity has been continually increasing. For example, Bechtel Corporation has indicated that from August 1974 to March 1977 the annual rate of increase in construction costs for nuclear fuel production was 8.8 percent to 10.0 percent; for power plants and transmission lines, 7.3 to 9.9 percent; and for electricity distribution, 3.0 to 4.4 percent.^{28/}

^{28/} Bechtel Corporation, Escalation in the Costs of Manpower, Materials, and Equipment Needed for Energy Facilities, by Paul F. Paskert and J. M. Gallagher, a report for the United States Energy Research and Development Administration (now U.S. Department of Energy), October 1977, pp. 1-5, 1-6.

Funds from new money sources accounted for 55 to 57 percent of total funds during 1970-73. The proportion increased to 62 percent in 1974 when construction expenditures rose to \$16.4 billion, \$1.5 billion over the 1973 level, and the aforementioned industry conditions reduced the significance of funds from operations. Another factor contributing to the greater proportion of new money was that the proportion of funds from the "Other Sources (Net)" category also declined in 1974. Information is not readily available to permit detailed analysis of this category. New money source decreased in relative and dollar size in 1975 and 1976 but in 1977 rose in dollar terms--to \$16.0 billion--and in relative terms--to 50 percent of total funds from operations.

Composition of New Money Sources. It should be noted that there has been a significant change in the sources of new money employed by IOUs at the beginning of the decade and those used in recent years. In 1970, long-term debt accounted for \$5.6 billion or 68% of total new money sources and there was no net increase in short term debt. However, since 1970 the relative importance of long term debt has declined, due largely to a trend of increasing interest rates, low interest coverage ratios and the fact that long

term debt, with its associated fixed charges, already constituted a large portion (see Table 2) of total capitalization in 1970. Since 1970, IOUs have increased their equity base and utilized considerable short term debt. For example, Table 1 indicates that IOUs stepped up their use of short term debt extensively in 1973 and 1974. In fact, the net increase in the short term debt category amounted to \$1.7 billion and \$3.0 billion in 1973 and 1974, respectively. This was 14 and 18 percent, respectively, of funds from new money sources in those two years.

Since 1974, there have been improvements in IOUs earnings, funds from operations, price earnings (P/E) ratios of common stocks and ratios of market price of common stock to book values. To be more specific, since 1974, earnings of IOUs have risen from \$5.3 billion to \$8.0 billion and funds from operations from \$8.6 billion to \$14.3 billion (see Table 3). The average P/E ratios for selected IOU stocks during the 1973-77 period were as follows:

10.02; 7.87; 7.38; 8.37; and 8.30.^{29/} The market to book ratio had declined significantly below 1.0 in 1974 for many companies but by 1977 it had risen to 1.01 on the average for the IOU sector.^{30/} The significance of the

^{29/} Op. Cit. Suraj Kanhouwa, p. 72, based on statistics of Standard & Poor's.

^{30/} Op. Cit. Suraj Kanhouwa, p. 73, based on information of the Edison Electric Institute.

market to book ratio is that if the ratio is below 1.0, it is unattractive for IOUs to issue common stock since each additional share of common stock issued lowers the average book value per share further. This tends to make common stock less attractive to investors. As a result, preferred stock is sometimes used instead. The improvements since 1974 in earnings, funds from operations, etc., have been accompanied by significant reliance on equity financing and Table 2 indicates the eventual impact upon the capitalization of IOUs.

Although net short-term debt, shown in Table 1, has decreased in relative importance as a source of new money since 1974, still, in 1977 it accounted for \$1.2 billion or 8 percent of new money sources, compared to nothing in 1970. Even though long-term debt has declined in proportion to total capitalization, as shown in Table 2, the average interest rate on the sum of long- and short-term debt has increased steadily for many years. It will continue to do so because over the next several years considerable amounts of long term debt, much of which was issued at 4 percent or less, is scheduled to mature and will have to be refinanced at much ^{31/} higher rates.

31/ U.S. Department of Energy (formerly Federal Power Commission), Op. Cit., Statistics of Privately Owned Electric Utilities in the United States, 1977 edition, p. 9.

Table 2. Composition of Capitalization for Classes A & B
Investor-Owned Electric Utilities

	Year End		
	<u>1977</u>	<u>1974</u>	<u>1970</u>
Long-term debt	50.7%	53.0%	54.8%
Preferred stock	12.3	12.2	9.8
Common equity and surplus	<u>37.0</u>	<u>34.8</u>	<u>35.4</u>
	100.0%	100.0%	100.0%

Source: U.S. Department of Energy, Statistics of Privately Owned Electric Utilities in the United States, Classes A and B Companies, 1977 edition, p. 33.

Other Factors. The last new money source in Table 1, "Other (Net)", has also increased as a percentage of total new money sources. In 1970 it was only \$142 million, or 2 percent of new money sources; in 1977 it was \$1.1 billion, or 7 percent of new money sources. Unfortunately, it is difficult to draw conclusions from this as adequate information is not available regarding its composition. It is known though that this category contains some proceeds from sales of fixed assets, which would more appropriately be contained in the final major category, "Other Sources (Net)".

Internally Generated Funds

Table 3 provides details of the composition of funds from operations for the 1970-77 period. Net income and depreciation, depletion and amortization (DD&A) account for the largest portion of funds from operations. However, although their dollar amounts increased during 1970-77, their relative size decreased because other factors grew faster. For example, in 1970, net income of \$3.4 billion and DD&A of \$2.4 billion were equal to 61 and 44 percent of funds from operations, respectively. In 1977, despite increases in net income to \$8.0 billion and DD&A to \$5.4 billion, their contribution to funds from operations decreased to 56 and 37 percent, respectively. During the same span,

Table 3. Composition of Internally Generated Funds for
Classes A and B Investor-Owned Electric Utilities,
1970-1977 (Million Current Dollars)

Year	Net Income	Depreciation Depletion & Amortization	Deferred Income Taxes (Net)	Investment Tax Credit Adjustment & Other Charges	AFDC ^a	Funds From Operations
1970	\$3,408	\$2,449	\$ 121	\$ 213	\$ (588)	\$ 5,603
1971	3,852	2,704	204	405	(812)	6,353
1972	4,419	3,003	360	556	(1,069)	7,269
1973	4,986	3,378	527	367	(1,237)	8,021
1974	5,297	3,737	788	357	(1,531)	8,648
1975	6,198	4,323	1,007	660	(1,645)	10,543
1976	7,194	4,808	1,347	1,335	(1,859)	12,825
1977	8,010	5,352	1,461	906	(1,392)	14,337

a/ AFDC (Allowance for Funds Used During Construction). Effective 1/1/77, Federal Energy Regulatory Commission Order No. 561 required that AFDC be subdivided into two categories, "Allowance for Other Funds Used During Construction" (AOFDC) and Allowance for Borrowed Funds Used During Construction" (ABFDC). Prior to 1/1/77, all AFDC was included in the one account. In 1977 the source document includes only AOFDC in calculating Funds From Operations; ABFDC is not included. Consequently, 1977 AFDC data are not exactly comparable with prior years. For example, in 1977 an AFDC figure of \$2,257 million (composed of both AOFDC and ABFDC) would be comparable to the 1976 AFDC figure of \$1,859 million. Thus, in 1977, total AFDC of \$2,257 million was equal to 28 percent of Net Income.

Source: U.S. Department of Energy (formerly Federal Power Commission) Statistics of Privately Owned Electric Utilities in the United States Classes A and B Companies, Washington, D.C., various issues, 1970 through 1977.

deferred taxes rose from 2 to 10 percent of funds from operations and the investment tax credit adjustment and other changes rose from 4 to 6 percent. The total of the four components exceeds 100 percent of funds from operations because the allowance for funds used during construction (AFDC) is noncash income and, therefore, must be deducted from net income to calculate funds from operations.

In 1970, AFDC was \$588 million or 10 percent of funds from operations. In 1977 AFDC, computed on a different basis, was \$1.4 billion, still approximately 10 percent of funds from operations.^{32/}

Net income is the residual item that results after all expenses have been deducted from all income. Therefore, net income is affected by economic conditions and the manner in which regulatory agencies allow IOUs to adapt to those conditions. Net income is affected by the rates utilities

^{32/} The AFDC figure in Table 3 for 1977 of \$1.392 billion, in accordance with Federal Energy Regulatory Commission procedure, was reported on a basis inconsistent with that used in prior years (see footnote a to Table 3, page 35). If 1977 AFDC had been reported in a manner similar to that used in 1976, it would have amounted to \$2.257 billion versus the \$1.859 billion in 1976; total funds from operations in 1977 would have been \$13.472 billion, i.e., \$14,337 - (\$2.257 - \$1.392), compared to \$12.825 billion in 1976 since all other categories would have remained unchanged. Therefore, on an adjusted basis, AFDC in 1977 would have been equal to 17% of Funds from Operations and 28% of Net Income.

are allowed to charge their customers, regulatory policy concerning AFDC, demand for electricity, interest rates, cost and availability of fuel, ability to pass on added costs in a timely manner, federal income tax laws, etc. IOU net income has grown from \$3.4 billion in 1970 to \$8.0 billion in 1977, or 135 percent. The rate of this growth slowed considerably in 1974 with the increase in fuel costs due to OPEC actions, time lags in passing on increased costs to customers and decreased U.S. consumption of electricity. Since 1974 though, net income has risen substantially due to increased electricity consumption, improvements in rates charged customers and benefits accruing from a more generous investment tax credit law.

Although net income increased 135 percent from 1970 to 1977, it can be argued that the quality of earnings decreased because, as discussed previously, AFDC has become an increasingly greater proportion of net income. This reflects increased construction costs and lengthened construction periods. In 1970 AFDC was 17.3 percent of net income, whereas in 1977 it was equal to 28.2 percent.^{33/} It should also be noted that trends in absolute dollar income figures alone can sometimes be misleading. A more detailed analysis might observe if trends in per share net income of individual IOUs coincide with trends in absolute dollar figures.

^{33/} Refer to footnote on Table 3.

Deferred income taxes, which were only \$121 million, or 2 percent of funds from operations in 1970, were \$1.5 billion or 10 percent of the total in 1977. The large increase is due, at least in part, to a 1969 federal tax law that resulted in greater use of normalization (i.e., deferred tax) policy by IOUs.

Investment tax credit adjustments and other charges rose from \$213 million in 1970 to \$906 million in 1977, or from 4 to 6 percent, respectively of funds from operations in those years. This category amounted to \$1.3 billion, or 10 percent of funds from operations in 1976. Supplementary data indicate that the decrease in 1977 is due to factors other than ITC. Details concerning other factors are not readily available but may reflect to some degree a limitation referred to earlier, inconsistencies in source document data. Nonetheless, the increased importance of this category compared to 1970 is due largely to the reestablishment of the investment tax credit in 1971 (it had been repealed in 1969) and the enactment by the Congress of the "Tax Reduction Act of 1975" which increased the amount of the credit from 4 to 10 percent.

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