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The Electric Utilities Rate Structure Determination

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THE ELECTRIC UTILITIES RATE STRUCTURE DETERMINATION

by

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Walid M. Kailani

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ABSTRACT

Electric Utilities Rate Structure Determination

by

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The purpose of this study is to analyze the determination of the rate structure of the electric utilities. It consists of three chapters.

The first chapter deals with the determination of the rate basis of electric utilities. The calculation of the rate base is explained, and also the problems of the price level changes.

The second chapter shows the calculation of the rate of return and the measures used for testing the fair rate of return.

The third chapter is an analysis showing the effect of the different cost and demand factors in determining the rate structure of electric utilities.

(72 pages)

INTRODUCTION

The regulation of public utilities by the Federal and State Commissions is becoming more important. In some vital economic enterprises, competition might fail to produce financial stability and growth to the producer, and to insure good service at reasonable rates for the consumer. The public utilities have high expenses in fixed assets. If the competition was allowed between these utilities it would lead to a waste of resources by over investment in fixed assets. As for reasonable rates for the consumer, if there was not regulation of rate structures of the utilities, they would charge the consumers high prices and produce low level of output.

For competitive enterprises, the market mechanism determines the price which in turn determines the success or failure of the enterprise. However, the regulating authorities determine the price of the regulated utilities through the rate adjustments. The regulatory commissions are charged with responsibility of setting rates of the regulated utilities which will be reasonable for the consumer and still allow a return to the utilities sufficient to enable them to continue provision of service.

Determining electrical rates is a very difficult problem. It can be summarized as a problem of joint costs with joint consumers, because it is hard to determine the cost of a particular unit of electricity due to many indirect costs, and it is hard to determine the specific consumer of that unit after its transmission from the generating station.

Since the regulation of electric utilities started, many arguments and many courts decisions have arisen in response to the need to determine fair rates for the utilities. Many rules were established and are followed in determining the price of electricity. Some rules are still subject to argument, but the important rule, known as the "End Result," was determined in the Hope Gas Case in 1944. According to that rule the earnings of the utility should be enough 1) to cover its operating expenses, 2) to maintain its credit position, 3) to yield a return sufficient to cover its cost of capital, and 4) to allow for its expansion.

CHAPTER I

THE RATE BASE OF ELECTRIC UTILITIES

Establishing the rate base of electric utilities is the first step in the rate structure determination. The relationship between the rate structure and the rate base is that the price of electricity should yield a reasonable rate of return on the property used to render the service. The first thing to consider in determining the rate base is the used and useful property of the electric utility, and the second thing is to determine the value of that property. The determination of the used and useful property leads to a discussion of the assets that comprise the rate base, and the value of the rate base leads to a discussion of the original cost and the fair value of the property.

The rate base equals the net plant plus the working capital.

Net Plant

The net plant equals the electric plant in service minus a reserve for depreciation, minus construction work in progress, minus a contribution in aid of construction, minus accumulated deferred income taxes, plus net common plant.[1]

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[1] Federal Power Commission. Statistics of Electric Utilities in the United States, Washington, D. C.: Federal Power Commission. 1965. p. 653.

Electric plant in service

Electric plant in service is an average of beginning and end of year balances of plant account. These accounts are divided into the following main groups: intangible plant, production plant, transmission plant, and distribution plant (for more details see Chart No. 1, page 5).

Reserve for depreciation

Depreciation refers to the value of the property used up in rendering the service. Some of the factors that cause depreciation are: the physical decrease in the value of the property, the change in circumstances, and the processes of innovation. Depreciation is charged to the operating expenses at the end of the financial period. The entry for charging depreciation to operating expenses has a debit-side called depreciation expense and a credit side called depreciation reserve. The balance of the depreciation reserve account represents the allocation of depreciation in succeeding years of the life of the depreciable item. At the life end of the equipment, the reserve for depreciation account is debted and the asset depreciated is credited.

The depreciation of the depreciable electric plant refers to that loss in its service value not restored by current maintenance.

> Depreciation as applied by depreciable electric plant means the loss in the service value not restored by current maintenance, incurred in connection with the consumption of prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given are wear and tear,

Rate Base = Net Plant +

Net plant = Electric plant in service--Reserve for depreciation--Construction work in progress--Contribution in aid of construction--Accumulated deferred income taxes + (Common plant--its reserve for depreciation)

Electric Plant in Service

Intangible Plant

- Organization
- Franchises and Consents
- Miscellaneous Intangible Plant

Production Plant

- Steam production plant
  - Land and land rights
  - Structures and improvements
  - Boiler plant equipment
  - Engines and engine driven generators
  - Trubogenerator units
  - Accessory electric plant
  - Miscellaneous
- Hydraulic Production Plant
  - Land and land rights
  - Structure and improvements
  - Reservoirs, dams, and water-ways
  - Water wheels, turbines and generators
  - Accessory electric equipment
  - Roads, railways, and bridges
- Other production plant
  - Land and land rights
  - Structures and improvements
  - Fuel holders, producers and accessories
  - Prime movers
  - Generators
  - Accessory electric equipment
  - Miscellaneous power plant equipment

Chart 1. Rate base.

Source: Federal Power Commission. Statistics of Electric Utilities in the United States. Washington, D. C.: Federal Power Commission. 1965.

Working Capital

Transmission

Land and land right
Clearing land and land
  right-of-way
Structures and improvements
Station equipment
Towers and fixtures
Poles and fixtures
Overhead conductors
  and devices
Underground conduit
Underground conductors
  and devices
Roads and trails

Common Plant in Service

Land and land rights
Structures and improvements
Office furniture and equipment
Transportation equipment
Stores equipment
Tools, shop and garage equipment
Laboratory equipment
Communication equipment
Miscellaneous equipment

Distribution Plant

Land and land rights
Structures and improvements
Station equipment
Storage battery equipment
Poles, towers, fixtures
Overhead conductors and devices
Underground conduit
Underground conductors and
  devices
Line transformers
Services
Meters
Installations on customer's
  promises
Leased property on customer's
  promises
Street light and signal system

decay, action of elements, inadequacy, obsolesences, changes in the art, changes in demand and requirement of public authorities.[2]

The term depreciable electric plant refers to the total electric plant in service minus the sum of the investment in the intangible plants,[3] minus land and land rights, minus electric plant leased to others, minus construction work in progress, minus electric plant held for future use, minus electric plant acquisition adjustment.[4] Another approach in computing the depreciable electric plant is to add the total production plant, the total transmission plant, and plus the total distribution plant, then subtract the land and land rights in any of the three plants mentioned. The definition for depreciation of the depreciable electric plant by the Federal Power Commission does not mean that the depreciable electric plant is the only item that counts for depreciation and retirement in the electric utility. In reference to the uniform system of accounts published by the Federal Power Commission the following retirements of electric plant are: intangible plant, production plant, transmission plant, distribution plant and general plant.

From these five items the depreciable electric plant includes three: the production plant, the transmission plant and the distribution plant. It does not include the reitrement of the intangible plant and the depreciation of the general plant.

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[2] Federal Power Commission. Electric Utility Depreciation Practices. Washington, D. C.: Federal Power Commission. 1958. Jacket.

[3] This form which is used in the Federal Power Commission is not suitable term because the intangible assets are not a plant.

[4] Federal Power Commission, p. 1.

The retirement of the intangible plant refers to the retirement of the intangible assets such as the franchise and organization expenses.

The depreciation of the general plant refers to the depreciation of the whole property included in the general plant (common plant) minus the land and the land rights.

Methods of calculating depreciation

The methods of accruing depreciation employed by 263 electric companies at the cose of 1958 were as follows.

Table 1. The distribution of 263 electric companies by the method of depreciation employed

Method of depreciation	Number of utilities	Per cent of total
Straight line	241	92
Interest	11	4
Retirement	9	3
Revenue	2	1
	263	100

Source: Federal Power Commission. Electric Utility Depreciation Practices. Washington, D. C.: Federal Power Commission. 1957. p. 1.

The straight line method. The straight line method is based on deducting equal amounts spread over the estimated life of the plant. Thus if an asset has a cost of \$11,000, a net salvage of \$1,000 and a service life of 40 years, the annual provision for depreciation equals:

$$\frac{\text{Total value of the asset--net salvage value}}{\text{Estimated life of the asset}}$$

i.e.

$$\frac{\$11,000--\$1,000}{40} = \$250.00$$

The interest method. It is called also the sinking fund method. According to this method the property is allocated to the years of service in increasing amounts in accordance with a compound interest method, in the first year of the life of the equipment, the depreciation expense is charged with a certain amount. The second year charge would be this amount plus the interest rate. The third year charge would be the fixed sum plus the interest rate all squared and so on until the total accumulation of the depreciation for the succeeding years equals the value of the equipment at the end of its estimated life.

The retirement method and the revenue method are not real methods of depreciation.

> The other depreciation methods represented above, the retirement method and the revenue method, should not, in fact, be termed methods of accruing depreciation. Since reserves for the ultimate retirement of property accumulated under these methods do not purport to measure the estimated depreciation of the associated property. Under the retirement method the reserves are based largely on an assumed uniform rate of property replacement adjusted as necessary for variation in the rate. In the revenue method the credit is a fixed percentage of revenues usually reduced by the amount spent for maintenance of the properties.[5]

As is shown in the table the revenue method and the retirement method are not widely used.

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[5] Federal Power Commission, p. 1.

The straight line method versus the interest method. The straight line method is simpler and more efficient than the interest method. There are some factors that should be taken into consideration when adopting a method of depreciation: wear and tear, the loss in the service value for any reason, and the depreciation as a source of internal finance.

In considering these factors the interest method is inefficient, because the change in art or demand may take place earlier in the life of the equipment, and the charges for depreciation might not be enough for the replacement.

When considering depreciation as a source for internal finance, the interest method is not able to accomplish this duty especially in the early life of the depreciable plant. Another disadvantage of the interest method is that when the plant is new, the maintenance expenses are low, but as the plant gets older, the maintenance expenses get higher. This means that if the interest method is adopted the cost of production would increase because of two factors: increase in the depreciation charges, and increase in the maintenance expenses.

The cost of the service should not be affected by the method of calculating depreciation. Depreciation is a real cost, and this cost should not be doubled several times at the end of the life of the plant as compared with the first year in service. The following table illustrates the difference in annual depreciation charges and reserve accumulation under a straight line method and the 6 per cent compound interest method. The example assumes an asset cost of \$10, 000, no net salvage, and a service life of 40 years. The figures are shown at five year intervals to simplify the presentation.

Table 2. Comparison between annual depreciation charges and reserve accumulation under a straight line method and a 6 per cent interest method

	Annual provision for depreciation		Reserve accumulation	
Year	Straight line	6% compound interest	Straight line	6% compound interest
1	$250	$ 64.61	$ 250	$ 64.61
5	250	81.57	1,250	364.24
10	250	109.17	2,500	851.67
15	250	146.08	3,750	1,503.95
20	250	195.50	5,000	2,376.88
25	250	261.62	6,250	3,545.05
30	250	350.11	7,500	5,108.34
35	250	468.53	8,750	7,200.38
40	250	627.00	10,000	10,000.00

Source: Case No. 5129, 1961 before the Public Service Commission of Utah. p. 10.

In the example above the annual provision of charge for depreciation expense is higher during the first 24 years under the straight line method. After the first 24 years the compound interest method exceeds the straight line. The higher the interest rate used in computing depreciation under the interest method, the greater the difference between the annual charges made under the interest method compared with charges made under the straight line method.

If the interest rate becomes zero the straight line method annual charges would equal the interest rate annual charges.

Table 3 shows the relationship between the depreciation reserves and the depreciable plant. (Frequency-distribution by method of depreciation accrual.) The ratio of the depreciation reserves to depreciable plant in the straight line method is 20.9 per cent compared with a ratio of 16.9 per cent for the interest method and 17.5 for other methods. This shows that the ratio of depreciation reserves to the depreciable electric plant is the highest under the straight line method of depreciation.

Table 4 shows the ratio of depreciation expense to depreciable plant. The straight line method has the highest ratio of 2.6 per cent compared with 1.9 per cent under the interest method, and 2.4 under other methods.

Construction work in progress and contribution in aid of construction

Contribution in aid of construction, construction work in progress and the plant held for future use; are not included in the net plant since they do not contribute to the current production. Investors should be compensated in the future for these items when they start to produce.

In reference to Chart 1, the construction work in progress the plant held for the future, and the contribution in aid of construction are not listed under the electric plant in service.

Accumulated deferred taxes

Accumulated deferred taxes should not be included in the rate base, because the deferred income tax is not an asset of the utility, but is a liability that should be paid in the future.

The preceding discussion explained how the Federal Power Commission computes the net plant. An analysis of the elements of each account followed that discussion showing the steps used in determining the net plant.

The first part of this chapter mentioned that the rate base as computed by the Federal Power Commission equals: Net plant plus working capital. A discussion and analysis of working capital follows.

Table 3. Electric utility depreciation practices--1958. Relation of depreciation reserves to depreciable plant--frequency distribution by method of depreciation accrual

Depreciation reserves per cent of depreciable plant	Utilities		Depreciation reserves		Depreciable plant		
	Number	Per cent of total	Amount (thousands)	Per cent of plant	Amount (thousands)	Per cent of total	Cumulative per cent
			Straight Line Method				
Under 15	25	11.5	447,337	13.0	3,432,428	11.6	11.6
15-19	55	25.2	1,679,542	17.9	9,358,652	31.6	43.2
20-24	65	29.8	2,507,056	22.4	11,217.169	37.9	81.1
25-29	38	17.4	1,199,774	26.3	4,559,195	15.4	96.5
30 and over	35	16.1	367,652	35.7	1,048,224	3.5	100.0
Total	218	100.0	6,201,361	20.9	29,615.668	100.0	
			Interest Method				
Under 15	4	50.0	62,065	11.4	543,910	22.2	22.2
15-19	3	37.5	349,762	18.4	1,899,062	77.7	99.9
20-24	1	12.5	345	21.4	1,610	0.1	100.0
25-29	---	-----	---------	-----	----------	-----	-----
30 and over	---	-----	---------	-----	----------	-----	-----
Total	8	100.0	412,172	10.9	2,444,582	100.0	-----
			Other Methods[a]				
Under 15	1	12.5	35,585	14.9	239,506	29.4	29.4
15-19	5	62.5	98,188	18.1	542,928	66.7	96.1
20-24	1	12.5	1,050	21.4	4,910	0.6	96.7
25-29	1	12.5	7,631	28.0	27,279	3.3	100.0
30 and over	---	-----	---------	-----	----------	-----	-----
Total	8	100.0	142,454	17.5	810,623	100.0	-----

[a]Retirement and revenue.

Source: Federal Power Commission. Electric Utility Depreciation Practices. Washington, D. C.: Federal Power Commission. 1958. p. 3.

Table 4. Electric utility depreciation practices--1958. Relation of depreciation expenses to depreciable plant--frequency distribution by method of depreciation accrual

Depreciation expenses per cent of depreciable plant	Utilities		Depreciation expenses		Depreciable plant		
	Number	Per cent of total	Amount (thousands)	Per cent of plant	Amount (thousands)	Per cent of total	Cumulative per cent
			Straight Line Method				
Under 2	13	6.0	24,209	1.7	1,450,630	4.9	4.9
2.0-2.4	37	17.0	121,344	2.3	5,222,864	17.6	22.5
2.5-2.9	101	46.3	517,663	2.7	19,097,073	64.5	87.0
3 and over	67	30.7	120,291	3.1	3,845,101	13.0	100.0
Total	218	100.0	783,607	2.6	29,615,668	100.0	-----
			Interest Method				
Under 2	3	37.5	6,390	1.5	418,487	17.1	17.1
2.0-2.4	4	50.0	40,764	2.0	2,024,485	82.8	99.9
2.5-2.9	1	12.5	47	2.9	1,610	0.1	100.0
3 and over	---	-----	---------	-----	----------	-----	-----
Total	8	100.0	47,201	1.9	2,444,582	100.0	-----
			Other Methods[a]				
Under 2	---	-----	---------	-----	----------	-----	-----
2.0-2.4	3	37.5	11,827	2.3	505,805	62.1	62.1
2.5-2.9	4	50.0	7,692	2.5	303,908	37.3	99.4
3 and over	1	12.5	169	3.4	4,910	0.6	100.0
Total	8	100.0	19,688	2.4	814,623	100.0	-----

[a]Retirement and revenue.

Source: Federal Power Commission. Electric Utility Depreciation Practices. Washington, D. C.: Federal Power Commission. 1958. p. 3.

Working Capital

Working capital is the amount of money required by a company to meet its current obligations. This amount of money should be included in the rate base so that the investors are compensated for the capital they supplied to the company. In determining the working capital for the electric utilities the following information is needed: Materials and supplies, prepayment, cash working capital, and 50 per cent of Federal income taxes. Working capital equals, the sum of the first three items minus the fourth.

Materials and supplies

The annual average value of the materials and supplies is used in determining the working capital. When these materials and supplies are used they will be included in the operating expenses. The amount invested in the materials and supplies stock depends on their turnover. If the utility keeps enough stock of materials and supplies for 50 days of production then the value of this stock represents the average value of materials and supplies which should be considered as a part of the working capital. The Federal Power Commission publishes in the electric utilities statistics, the stocks and day supply of coal and oil for the production of electric utilities.

Prepayments

The average prepayments are included in the working capital. The idea behind including these prepayments in the working capital is that they represent expenses which do not belong to current period of the production. If these prepayments were not made their balances would be absorbed in some other balances usually in cash or supplies.

Cash working capital

The amount of the cash to be included in the working capital is calculated to be one-eighth of the current annual electric operation and maintenance expenses minus purchased power.

The theory, used in determining one-eighth of the operating expenses for the cash working capital, may be that cash turnover of the operation and maintenance expenses is approximated to be eight times per year.

The purchased power should not be included in the working capital and thus not in the rate base, since it is not an investment in the utility.

Federal income taxes

Working capital is defined as the sum of the first three items minus the tax. Fifty per cent of Federal income taxes charged is deducted from the above three items. The time between the accrual and the payment of the taxes results in the accumulation of funds which may be used as a means of temporary financing. The Federal income tax is not an asset of the utility, but a liability, and should not be considered in the working capital.

The Rate Base and the Price Level Changes

When the price level goes up, the real value of the money decreases, thus effecting purchasing power. The replacement cost of an asset would be greater than it was in the past in terms of current prices. If the value of the plant in service and the general plant are calculated at the original cost and if there was no adjustment in the rate base or the rate of return the investor will suffer. To explain this let us assume an investor having $1000 in capital giving him 10 per cent return his income would be $100. Then let us assume that the price level doubled. The investor would be able to buy one half as much with his return as he did before the inflation. If the $1000 were inflated to be $2000 at the per cent return his income would be $200 which has the same purchasing power as the $100 before the inflation.

If the price level decreased the opposite will happen the investor income would double as a result of the doubling of the purchasing power of the money.

The fair value doctrine

In 1893 the stockholders of the Union Pacific Reailway Company, and other railroads operating in Nebraska challenged the decision of establishing a maximum rate of return by the State Board of Transportation on the basis that these rates were confiscatory. The Supreme Court held that the rates were confiscatory and enumerated specific measures to be considered in determining the rates of the regulated companies. Justice Harlan said:

> We hold, however, that the basis of all calculations as to the reasonableness of rates to be charged by a corporation maintaining a highway under legislative sanction must be the fair value of the property being used by it for the convenience of the public. And in order to ascertain that value, the original cost of construction, the amount expended in permanent improvements, the amount and market value of its bonds and stock, the present as compared with the original cost of construction, the probable earning of the property under particular

> rates prescribed by statue, and the sum required to meet operating expenses, are all matters for consideration, and are to be given such weight as may be just and right in each case. We do not say that there may not be other matters to be regarded in estimating the value of the property. What the company is entitled to ask is a fair return upon the value of that which it employs for the public convenience.[6]

Thus the court measured of value to be considered in determining the fair value are:

1. The original cost of construction and the amount spent on permanent improvements,
2. The amount of bonds and stocks,
3. The market value of bonds and stocks,
4. The present as compared with the original cost of construction,
5. The probable earning capacity of the property, and
6. Operating expenses.

The Smyth v. Ames Case, became the bases of the fair value doctrine in determining the rate base of the regulated utilities. In the Minnesota Cases, Mr. Justice Hughes referred to Smyth v. Ames Case in determining the rate base:

> The bases of calculation is the fair value of the property used for the convenience of the public.[7]

Some of the measures mentioned in determining the fair value in Smyth v. Ames Case are still considered. Others have been rejected.

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[6] Irston R. Barnes (Ed.). Cases on Public Utility Regulation. (Smyth v. Ames). New York: F. S. Crofts and Co. 1938. p. 378.

[7] Ibid., (The Minnesota Rate Cases B), p. 384.

> Of these measures specifically mentioned, four were subsequently rejected as a proper measure of value. Earning capacity and the market value of bonds and stocks involve circular reasoning, because they depend on the companies earnings which in turn, depend on the rate charged. The amount of bonds and stock also has been rejected, for to base valuation for rate-making purposes on this amount would encourage stock watering and over capitilization. And operating expenses have nothing to do with the determination of the rate base. As a result, two measures remain (1) Original cost, including expenditures on permanent improvements; (2) present, current, or reproduction cost.[8]

Reproduction cost. In 1909 when the price started to rise the reproduction cost became more and more important. The courts argued that the companies are entitled to any increase in property value.

> And we concur with the court below in holding that the value of the property is to be determined as of the time when the inquiry is made regarding the rates. If the property, which legally enters into the consideration of the question of rates, has increased in value since it was acquired, the company is entitled to the benefit of such increase. This is at any rate the general rule.[9]

In determining the reproduction cost, some problems arise because this cost is a theoretical estimate. Wilcox has proven this by asking some questions which could be summarized as follows;

1. What is it that is being reproduced. A modern replacement for an old plant? The old plant in its original condition? or a modern replacement of it?

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[8] Charles F. Phillips Jr. The Economics of Regulation. Homewood, Illinois: Richard D. Irwin, Inc. 1965. p. 219.

[9] Clair Wilcox. Public Policies Toward Business. Homewood, Illinois: Richard D. Irwin, Inc. 1960. p. 572.

2. Under what conditions is the reproduction cost to occur? Those original existing conditions or conditions existing at the present?

3. Is it going to be a reproduction on a large scale operations with modern techniques? Or on a small scale with techniques no longer in use?, and

4. What prices are to be taken? The spot prices of a certain day? An average price of a recent period? Or the future prices?

Original cost. The original cost is easy and simple to determine, with fair accuracy from the records of the utility if records are available and complete. It is a stable rate base which changes only when there are changes in the property by addition or retirement. The original cost was the main factor considered in determining the rate base before the emphasis on the reproduction cost. After Smyth v. Ames Case the reproduction cost and the original cost were both to be considered in determining the rate base. Since 1944 there was a shift from the fair value to the "End Result Doctrine."

The End Result Doctrine

The "End Result" started in 1933 with the Los Angeles Gas Case.

> With disatisfaction being expressed both in and outside the Supreme Court, it was perhaps inevitable that a shift in emphasis would be forthcoming. That shift began with the Los Angeles Gas Case in 1933 and culminated with the Hope Natural Gas Case in 1944. In Los Angeles Case, the California Commission made two valuations. One based on "historical cost" and the other on "fair value." It then reduced the company's gas rates. The new rates were estimated to produce a 7.7 percent rate of return on historical cost and 7 percent on fair value. The court, upholding the order, held that the choice

of valuation measure was within the discretion of the commission.[10]

The "End Result" Doctrine became strong in 1944 with the case of the Hope Natural Gas Company. As a result of the court's decision the commissions became free to use any measure in determining the rate base of the regulated company as long as the method used provides a reasonable rate of return to the investors. In expressing the opinion of the court, Justice Douglas said:

> Under the statutory standard of just and reasonable it is the result reached not the method employed which is controlling. . . . It is not the theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the act is at end . . . As we have noted the commission fixed a rate of return which permits Hope to earn 2, 191, 314 annually. In determining that amount it stressed the importance of maintaining financial integrity of the company. It considered the financial history of Hope and a vast array of data bearing on the natural gas industry, related business, and general economic conditions . . . Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid, even though they might produce only a meager return on the so-called "fair value," rate base.[11]

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[10] Philips, p. 227.

[11] Burton A. Kolb and Otis Lipstren. New Concepts and Current Issues in Public Utility Regulation. Denver, Colorado: Peerless Publishing Company. 1963. p. 13.

Conclusion

The determination of the rate base was the main step in setting the electric utility rates. The original cost was the main factor in determining the rate base until 1893, when the Smyth v. Ames Case arose. According to the decision of the court many factors were considered in determining what the court called the "fair value." These factors were the original cost, the reproduction cost, the market value of the bonds, the probable earnings, and the operating expenses.

Since 1933 there was a shift from the "fair value" to the "End Result" Doctrine. According to this doctrine the rates should enable the company to maintain its credit standing, to obtain necessary replacement funds, and to maintain the real income of the investor.

CHAPTER II

THE RATE OF RETURN

The rate of return as computed by the Federal Power Commission is found by dividing the net income by the rate base.

It was shown in the previous chapter how to calculate the rate base. An explanation of how to calculate the net income follows.

When determining the net income two things should be known: net operating revenue and provision for deferred income taxes.

Net Operating Revenue [1]

Net operating revenues equal total electric operating revenues minus total operating expenses.

Total electric operating revenues

Total electric operating revenues equal the summation of revenues from the consumers and revenues from sales of electricity for resale. Ultimate consumers are divided into groups such as residential, commercial, industrial, etc. The sales for resale come from sales to other small companies, municipalities, and big companies through the interconnection of electric companies.

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[1]See Chart 2, page 24.

Rate of Return = Net income/Rate Base

Net Income = Total Revenue - Total Operating Expenses + provision for deferred income taxes

Total Revenue		Total Operating Expenses
Revenues from Ultimate Consumers Residential Commercial and Industrial small or commercial, large or industrial Public street and highway lighting Other Public Authorities Railroads and Railways Interdepartmental	Revenues from sales for resale	Operating expense Maintenance expense Depreciation expense Amortization Taxes other than income taxes Income taxes-- Federal Other Provision for deferred income taxes Income taxes deferred in prior years or investment tax credit adjustment (net)

Chart 2. Rate of return.

Total operating expenses

Total operating expenses include operating expenses. maintenance expense, depreciation expense, amortization and taxes. The item operating

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[2] For more details concerning the rate base see Chart No. 1, p. 5.
Source: Federal Power Commission. Statistics of Electric Utilities in the United States. Washington, D. C.: Federal Power Commission. 1965.

expense includes all types of operating expenses such as: materials and supplies, fuel, wages and salaries.

Provision for deferred income taxes

The Federal Power Commission determines the net income by adding the provision for deferred income taxes to the net operating revenues. The provision for deferred income taxes is listed under the total operating expenses in the uniform system of accounts required by the Federal Power Commission. Actually this item is not an expense, it is a reserve. Since it was included under operating expenses, and was deducted from total revenue, it should be added to the operating expenses in order to get the actual operating expenses.

Now the rate of return can be calculated by dividing the net income by the rate base as shown in Chart No. 2.

The Fair Rate of Return

Court decisions have upheld the general principal that regulated utilities are entitled to a fair return on the fair value of their investment. There is no specific rate of return that is always fair. The fair rate of return changes with the changes in the factors that are considered in determining that specific fair rate of return. The determination of the fairness of a rate of return can be determined by testing that rate of return under the present conditions.

> What is a fair return..... cannot be settled by invoking decisions of this court made years ago based upon conditions radically different from those which prevail today. The problem is one to be tested primarily by present day conditions . . . What will constitute a fair return in a given case is not capable of exact mathematical demonstration . . .[3]

Tests for the fairness of the rate of return

A rate of return in order to be fair should be sufficient to cover the cost of capital and to attract it.

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for capital costs of the business. These include service on the debt and dividend on the stock..... By that standard the returns on investments in other enterprises having corresponding risks. That return moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.[4]

Cost of capital. The first test for the fairness of the rate of return is the cost of capital. The cost of capital refers to the average return paid to the capital owners and the bond holders. By analyzing the capital structure of the electric utility three sources of finance are found. They are: capital preferred stock, common stock, and long-term debt. Each of these sources

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[3]Justice George Sutherland, United Railways and Elect Com. v. West. 280 U. S., p. 234,251, 1930.

[4]Justice William Douglas, Federal Power Com. v. Hope Gas Co. 380 U. S., p. 591,603, 1944.

should have a different rate of return depending on the degree of risk in capital and the assurance of the return. The long term debt has the lowest rate of return, because the return is guaranteed, and there is little risk involved in losing the principle. In case of liquidation the bond holders have priority over the share holders.

The preferred stock holders have a lower rate of return, than the common stock holders because the preferred stock holders have priority in the rate of return when profits are distributed, and priority in principle when the company is liquidated.

The highest return to the common stock holders because they have the greatest degree of risk in return and in capital. An analysis of the Utah Power and Light Company capital structure and long term debt might be helpful in explaining the cost of capital.

Capital Paid in (1966)

Cumulative Preferred Stock (authorized, 2,000,000 shares of $25 each, issuable in series--outstanding.

$1.28 series A, 400,000 shares	10,000,000
$1.18 series B, 480,000 shares	12,000,000
$1.16 series C, 200,000 shares	5,000,000
Total	27,000,000

Common stock (authorized, 7,500 shares at $12.80 each outstanding 4846,240 shares, dividens 1.54 in 1966 and 1.46 in 1965.

1.46 in 1965.	62,671,872
Capital paid in excess of paid value	4,867,477
Total	94,539,349

Long term debt

First mortgage bonds	
2-3/4 per cent series due 1967	32,000,000
3-1/8 per cent series due 1978	3,000,000
3- per cent series due 1979	3,000,000
2-7/8 per cent series due 1979	3,000,000
2-7/8 per cent series due 1980	8,000,000
3-5/8 per cent series due 1981	9,000,000
3-1/2 per cent series due 1982	10,000,000
3-1/4 per cent series due 1984	15,000,000
3-5/8 per cent series due 1985	15,000,000
4-7/8 per cent series due 1990	16,000,000
4-1/2 per cent series due 1992	22,000,000
4-1/2 per cent series due 1993	15,000,000
4-5/8 per cent series due 1994	15,000,000

The following data is from the financial statement of the Utah Power and Light Company for the year 1966. The cost of the common stock is $12. 80 per share. The return per share was $1. 46. The rate of return would be equal to 12 per cent.

The nominal rate of return to the preferred stockholders would equal the dividends divided by the share value which would yield 5. 12 per cent for series A share holders, 4. 72 per cent for series B, and 4. 64 for series C. The mean rate of return for the capital and the bonds which is the cost of capital to the company, is 5. 6 per cent. In order to be fair the rate of return should cover the cost of capital and should not be less than 5. 6 per cent.

Attracting capital. The second test for the fairness of the rate of return is the attracting of capital. The investors decision to invest depends on the rate of return, the degree of risk, and the degree of liquidity. If the rate of return increases, other things being equal, the supply of loanable funds should increase. The demand for the loanable funds depends on the interest rate and the marginable efficiency of capital.

r = interest rate
I = investment
S = supply of loanable funds
D = demand of the loanable funds

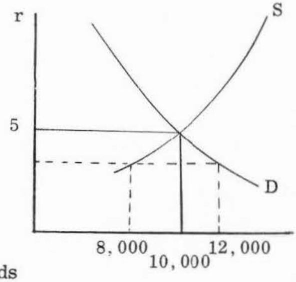

Figure 1. Supply and demand for loanable funds

Consider the following example. At an interest rate of 5 per cent the supply of loanable funds is \$8,000 and the demand is \$12,000. The equilibrium point is \$10,000 at an interest rate of 6 per cent. Actually the loanable funds market is almost a competitive market, and if the utility does not pay the prevailing interest rate paid by the other competitive companies in the capital market, which have the similar degree of risk, it might not be able to attract any capital, but if it pays the current interest rate it might get as much capital as it needs. From the notes on capital page 27, it is found that a part of the bonds was borrowed at 2 3/4 per cent interest rate while the current price for bonds is almost 5 per cent. If the bonds with 2 3/4 per cent interest rate are retired, the company would not be able to attract the replacement unless it pays the current rate of return. The average rate of return should be at least 5. 60 per cent to meet the increment in the interest rate of the new bonds. If the average rate of return did not increase, the result would be a drop in the rate of return of the stock-holders. Thus, in order to maintain the credit of the company the rate of return should consider the increment in the interest rate of new bonds.

The following table shows the rate of return for 192 electric companies in the United States between 1961-1965. The calculation of these rates of return was done on a uniform basis, described at the beginning of this chapter. In 1965, Table 1 shows that the lowest interest rate was 3. 52 earned by Electric Energy Inc. The highest rate of return was 13. 30 earned by New Orleans Public Service Inc. The rate 3. 52 per cent is too low and it does not meet the two tests of meeting the cost of capital and attracting capital, since the prevailing interest rate in the bond market is about 5 per cent.

The stockholders would have a very low rate of return of their investments. This confirms the idea that the fair rate of return is not guaranteed for the regulated companies. On the other hand, the rate of return of 13. 30 is a little high compared with other electric utilities. The regularing commissions could allow the regulared utilities to earn a high rate of return as a result of efficiency. The table shows that there is not much difference between the rates of return. Whether they could be considered fair rates of return depends on the circumstances of the company.

Table 5. Per cent of return earned on rate base of 192 electric companies 1961-65

Company	1961	1962	1963	1964	1965
Alabama Power Co.	7.11	7.08	7.01	7.83	7.28
Appalachian Power Co.	6.73	7.55	7.40	7.36	7.01
Arizona Public Service Co.	6.65	6.63	6.23	5.83	5.48
Arkansas-Missouri Power Co.	6.23	7.63	7.38	7.81	8.14
Arkansas Power and Light Co.	6.53	6.64	6.84	7.22	7.75
Atlantic City Electric Co.	7.00	6.69	6.75	6.63	6.92
Baltimore Gas and Electric Co.	6.91	6.61	6.83	7.07	7.66
Bangor Hydro-Electric Co.	6.73	6.98	6.98	6.98	7.07
Black Hills Power and Light Co.	7.75	7.09	6.95	6.49	6.55
Blackstone Valley Electric Co.	11.38	10.74	11.18	9.00	9.34
Boston Edison Co.[a]	6.70	6.88	7.24	7.07	7.41
Brockton Edison Co.	7.78	7.95	9.63	8.73	9.11
California Pacific Utilities Co.	6.01	5.28	5.66	6.56	5.82
Cambridge Electric Light Co.	7.75	7.84	8.22	8.05	8.32
Cape and Vineyard Electric Co.	7.23	7.88	7.84	8.59	7.95
Carolina Power and Light Co.	6.73	6.88	6.98	7.39	7.68
Central Hudson Gas and Electric Corp.	6.43	6.46	6.48	6.63	6.87
Central Illinois Electric and Gas Co.	8.58	8.58	8.73	9.66	9.66
Central Illinois Light Co.	6.30	7.57	8.12	8.10	8.63
Central Illinois Public Service Co.	8.25	8.35	8.87	9.00	8.14
Central Kansas Power Co.	6.20	6.54	6.42	7.33	7.62
Central Louisiana Electric Co., Inc.	8.15	8.46	8.71	8.90	9.23
Central Maine Power Co.	5.95	6.02	6.12	6.29	6.49
Central Power and Light Co.	8.02	8.63	8.75	9.00	9.20
Central Vermont Public Service Corp.	6.05	6.03	6.07	6.38	6.26
Cheyenne Light, Fuel and Power Co.	9.82	8.65	8.05	7.15	6.77
Cincinnati Gas and Electric Co.	8.07	7.28	7.53	8.07	8.55
Citizen Utilities Co.	7.24	7.38	9.44	10.28	9.67
Cleveland Electric Illuminating Co.	7.13	6.91	7.02	7.48	8.29
Columbus and Southern Ohio Electric Co.	6.86	5.91	6.69	6.85	7.49
Commonwealth Edison Co.	7.84	7.85	7.89	8.04	8.56
Commonwealth Edison Co. of Indiana, Inc.	6.11	6.91	6.65	6.68	6.42
Community Public Service Co.	8.65	9.14	9.08	9.34	8.77
Concord Electric Co.	7.47	7.20	7.38	7.12	7.03
Connecticut Light and Power Co.	6.69	6.71	6.65	6.75	6.88

Table 5. Continued

Company	1961	1962	1963	1964	1965
Conowingo Power Co.	4.89	4.90	5.65	4.99	6.18
Consolidated Edison Co. of New York, Inc.	5.36	5.40	5.18	5.18	5.35
Consolidated Water Power Co.	8.63	7.28	2.61	3.84	9.60
Consumers Power Co.	6.82	6.73	6.98	7.51	7.95
Dallas Power and Light Co.	7.40	7.98	9.33	8.44	7.99
Dayton Power and Light Co.[b]	7.40	7.52	7.55	8.03	8.17
Delaware Power and Light Co.	6.42	6.73	7.21	7.48	7.72
Detroit Edison Co.	6.84	7.08	7.43	7.92	8.38
Duke Power Co.	6.78	7.54	6.98	7.41	7.90
Duquesne Light Co.	7.42	7.51	7.67	7.93	8.06
Eastern Shore Public Service Co. of Maryland	6.12	4.80	5.18	5.44	5.70
Edison Sault Electric Co.	9.31	9.59	9.43	10.00	9.41
El Paso Electric Co.	8.36	8.98	9.20	9.52	9.97
Electric Energy, Inc.	3.53	3.56	3.51	3.52	3.52
Empire District Electric Co.	7.13	7.88	8.07	8.22	8.30
Fall River Electric Light Co.	7.04	8.16	9.59	7.44	7.89
Fitchburg Gas and Electric Light Co.	7.01	7.03	6.83	6.98	7.31
Florida Power Corp.	7.54	8.08	7.87	7.91	7.97
Florida Power and Light Co.	7.74	8.32	8.31	8.72	8.21
Georgia Power Co.	6.88	7.26	6.94	7.35	7.41
Granite State Electric Co.	7.09	6.38	5.97	6.25	7.24
Green Mountain Power Corp.	6.57	6.79	6.76	6.76	6.80
Gulf Power Co.	7.36	7.59	7.73	8.18	7.85
Gulf State Utilities Co.	6.97	7.56	7.41	7.54	8.17
Hartford Electric Light Co.	5.73	6.15	7.03	6.93	6.86
Hawaiian Electric Co.	7.26	7.86	7.42	7.14	7.39
Hilo Electric Light Co., Ltd.	7.91	8.47	7.43	8.02	7.57
Holyoke Power and Electric Co.	10.39	5.83	5.71	6.00	5.67
Holyoke Water Power Co.	10.03	7.30	7.61	8.03	7.37
Home Light and Power Co.	7.56	7.51	8.01	8.62	7.20
Houston Lighting and Power Co.	7.50	8.62	9.34	9.97	11.32
Idaho Power Co.	6.14	5.83	6.45	6.62	6.74
Illinois Power Co.	8.24	8.58	9.18	8.99	9.16
Indiana-Kentucky Electric Corp.	3.67	3.65	3.64	3.62	3.73
Indiana-Michigan Electric Co.	6.05	6.55	6.91	7.43	7.71

Table 5. Continued

Company	1961	1962	1963	1964	1965
Indianapolis Power and Light Co.[a]	7.95	8.31	8.26	8.53	9.12
Interstate Power Co.	7.51	7.30	7.14	7.18	7.30
Iowa Electric Light and Power Co.[a]	7.73	8.06	8.06	7.95	8.18
Iowa-Illinois Gas and Electric Co.	7.70	7.51	8.14	8.70	9.07
Iowa Power and Light Co.	6.14	6.17	6.28	6.28	6.39
Iowa Public Service Co.	6.99	7.06	7.36	7.25	7.33
Iowa Southern Utilities Co.	7.08	7.99	8.09	8.07	9.26
Jersey Central Power and Light Co.	6.80	6.52	6.94	7.03	7.08
Kansas City Power and Light Co.	6.69	7.00	7.31	7.36	7.18
Kansas Gas and Electric Co.	6.74	7.02	7.50	7.56	7.61
Kansas Power and Light Co.	7.80	8.03	8.12	9.14	8.15
Kentucky Power Co.	7.85	9.90	9.62	8.01	8.02
Kentucky Utilities Co.	7.72	7.85	8.08	8.37	8.69
Kingsport Power Co.	6.49	6.94	6.31	6.53	6.02
Lake Superior District Power Co.	6.78	6.89	6.81	6.92	6.65
Long Island Lighting Co.[c]	6.97	6.72	6.41	7.09	7.42
Louisville Power and Light Co.	7.25	7.31	7.40	7.89	7.17
Louisville Gas and Electric Co.	8.00	8.13	8.10	8.56	8.99
Madison Gas and Electric Co.	7.42	7.25	7.50	7.43	5.83
Maine Public Service Co.	7.44	7.03	8.00	6.85	5.41
Marietta Electric Co.	5.98	5.95	6.35	6.56	7.02
Massachusetts Electric Co.	7.87	5.80	5.43	5.39	5.92
Maui Electric Co.	6.91	7.23	6.88	6.76	6.01
Metropolitan Edison Co.	7.23	7.10	7.32	7.63	7.45
Michigan Gas and Electric Co.	9.43	8.40	9.04	9.03	8.72
Minnesota Power and Light Co.	6.08	6.26	6.27	6.39	6.65
Mississippi Power Co.	7.64	8.11	7.88	7.78	8.10
Mississippi Power and Light Co.	6.88	6.97	7.13	7.21	8.42
Missouri Edison Co.	7.60	7.70	7.25	7.79	6.35
Missouri Power and Light Co.	6.62	7.44	7.21	7.44	6.92
Missouri Public Service Co.	5.82	6.14	6.17	6.70	7.11
Missouri Utilities Co.	6.23	6.80	7.36	6.51	6.47
Monongahela Power Co.	6.96	7.18	7.31	7.32	7.64
Montana-Dakota Utilities Co.	5.34	5.42	6.42	6.52	6.76
Montana Power Co.	9.78	10.12	10.24	10.92	11.37

Table 5. Continued

Company	1961	1962	1963	1964	1965
Montaup Electric Co.	5.79	5.64	6.85	5.85	5.69
Nantahala Power and Light Co.[d]	5.19	7.59	9.20	10.12	10.53
Narragansett Electric Co.	4.96	4.77	4.84	5.18	5.58
Nevada Power Co.	8.39	7.79	8.21	8.23	7.13
New Bedford Gas and Electric Co.	7.54	8.12	7.87	7.20	8.79
New England Power Co.	4.51	5.95	6.52	6.46	6.57
New Hampshire Electric Co.	6.49	6.51	6.08	5.89	5.76
New Jersey Power and Light Co.	6.85	6.66	6.82	6.75	6.89
New Mexico Electric Service Co.	9.29	9.25	9.57	9.99	11.78
New Orleans Public Service, Inc.[a]	10.88	12.27	13.04	13.17	13.30
New York State Electric and Gas Corp.	6.91	6.78	6.67	6.77	7.27
Newport Electric Corp.	7.28	7.13	7.56	8.30	7.55
Niagara Mohawk Power Corp.	5.66	5.85	5.82	5.82	6.36
Northern Indiana Public Service Co.	8.59	8.38	8.37	8.81	9.13
Northern States Power Co. (Minnesota)	7.44	8.05	8.34	8.07	7.88
Northern States Power Co. (Wisconsin)	6.55	6.63	6.54	6.60	7.33
Northwestern Public Service Co.	8.13	7.29	8.97	8.57	7.73
Ohio Edison Co.	7.32	6.96	7.33	7.93	8.73
Ohio Power Co.	6.59	6.77	7.26	7.47	8.16
Ohio Valley Electric Corp.	4.15	4.13	4.14	4.10	4.26
Oklahoma Gas and Electric Co.	6.75	7.47	8.04	8.13	8.93
Old Dominion Power Co.	5.19	5.70	5.26	5.13	5.62
Orange and Rockland Utilities, Inc.	6.43	6.45	6.52	7.00	7.50
Otter Tall Power Co.	5.93	6.14	6.77	6.39	7.02
Pacific Gas and Electric Co.	6.21	6.47	6.43	6.29	6.87
Pacific Power and Light Co.	6.19	6.45	6.39	6.12	6.34
Pennsylvania Electric Co.	7.13	6.71	7.06	7.07	6.95
Pennsylvania Power Co.	7.56	8.10	8.40	7.94	7.86
Pennsylvania Power and Light Co.	6.51	6.47	6.63	6.77	6.80
Philadelphia Electric Co.	6.27	6.44	6.55	6.93	7.21
Plymouth County Electric Co.	6.90	6.94	6.75	6.27	5.79
Portland General Electric Co.[e]	6.50	6.94	6.75	6.27	5.79
Potomac Edison Co.	7.81	7.95	7.87	7.21	7.49
Potomac Edison Co. of Pennsylvania[f]	6.62	5.69	7.10	5.96	5.48
Potomac Edison Co. of Virginia[g]	5.36	5.51	5.35	5.46	5.68

Table 5. Continued

Company	1961	1962	1963	1964	1965
Potomac Edison Co. of West Virginia	6.28	6.19	6.01	5.97	5.89
Potomac Electric Power Co.	6.98	6.73	6.97	6.62	6.58
Public Service Co. of Colorado	7.83	7.48	7.68	7.66	7.41
Public Service Co. In Indiana, Inc.	6.48	6.78	7.06	7.47	8.20
Public Service Co. of New Hampshire	5.68	6.41	5.98	5.96	5.34
Public Service Co. of New Mexico	7.95	8.09	8.11	8.07	8.43
Public Service Co. of Oklahoma	7.17	7.44	8.00	7.99	8.10
Public Service Electric and Gas Co.	7.01	7.22	7.14	7.04	7.22
Puget Sound Power and Light Co.	6.38	6.28	5.46	5.37	5.59
Rochester Gas and Electric Corp.	6.20	6.65	7.12	7.10	6.84
Rockland Electric Co.	6.75	6.52	7.24	7.34	6.81
Safe Harbor Water Power Corp.	5.12	5.09	5.06	5.10	5.06
St. Joseph Light and Power Co.	8.05	8.06	8.23	7.86	7.53
San Diego Gas and Electric Co.	6.39	6.30	6.31	6.13	6.50
Savannah Electric and Power Co.	7.48	7.22	7.37	7.96	8.26
Sierra Pacific Power Co.	8.83	7.99	8.92	7.55	6.93
South Carolina Electric and Gas Co.	7.68	7.87	7.45	7.49	7.87
Southern California Edison Co.	6.71	6.61	6.64	6.55	6.69
Southern Electric Generating Co.	7.67	7.97	7.94	7.72	7.44
Southern Indiana Gas and Electric Co.	6.71	6.95	7.63	8.41	8.73
Southwestern Electric Power Co.	7.82	8.48	9.23	8.91	9.06
Southwestern Electric Service Co.	6.74	6.76	7.13	7.28	7.13
Southwestern Public Service Co.	7.24	8.01	8.35	8.56	7.93
Superior Water, Light and Power Co.	7.65	7.47	8.05	7.25	7.55
Tampa Electric Co.	7.64	8.33	8.92	8.89	8.49
Tapoco, Inc.	5.64	5.88	7.63	6.83	7.14
Texas Electric Service Co.	8.38	8.85	9.00	8.59	8.50
Texas Power and Light Co.	8.51	9.06	9.67	10.22	9.01
Toledo Edison Co.	6.32	6.81	6.78	7.11	7.31
Tucson Gas and Electric Co.	7.85	8.32	7.48	7.69	7.89
Union Electric Co.	6.61	6.60	6.47	6.66	6.97
Union Light, Heat and Power Co.	6.48	5.93	6.04	6.77	7.03
United Gas Improvement Co.	5.77	5.40	5.43	6.13	6.93
United Illuminating Co.	7.22	7.19	7.52	7.45	7.79
Upper Peninsula Generating Co.	3.42	3.47	3.83	4.87	3.66

Table 5. Continued

Company	1961	1962	1963	1964	1965
Upper Peninsula Power Co.	8.27	8.60	8.49	8.65	8.69
Utah Power and Light Co.	6.17	6.20	6.33	5.65	6.08
Vermont Electric Power Co.	5.66	5.39	5.16	5.17	5.16
Virginia Electric and Power Co.	7.02	7.41	7.26	7.20	7.39
Washington Water Power Co.	6.09	6.01	5.93	6.26	6.21
West Penn Power Co.	7.33	7.57	7.23	7.43	7.75
West Texas Utilities Co.	9.28	9.48	9.40	9.72	9.51
Western Colorado Power Co.	4.83	4.64	4.72	4.95	5.19
Western Massachusetts Electric Co.	6.78	7.52	7.14	7.54	7.72
Western Power and Gas Co., Inc.[i]	7.26	7.41	8.25	7.57	6.48
Wheeling Electric Co.	5.89	5.65	5.40	5.86	5.58
Wisconsin Electric Power Co.	6.06	6.12	6.42	6.70	7.10
Wisconsin Michigan Power Co.	5.94	6.15	6.08	5.95	5.60
Wisconsin Power and Light Co.[j]	7.25	7.16	7.40	7.36	7.78
Wisconsin Public Service Corp.	7.42	7.93	8.16	7.31	7.36
Yadkin, Inc.	6.07	6.20	7.73	6.55	7.41
Yankee Atomic Electric Co.	3.40	6.39	6.99	7.48	7.90

[a] Company reports depreciation for combined utilities. Rate of return for electric utility based on allocation of depreciation to electric plant on the basis of gross average electric plan to gross average total plant.

[b] Prior to 1964, the company reported depreciation for combined utilities. See note a.

[c] Long Island Lighting Co. acquired Patchogue Electric Light Co. through merger June 1, 1964

[d] Company made a refund of $905,658 to its customers in 1965 in accordance with a North Carolina Commission order stipulating a retroactive rate decrease for the years 1961 through 1963. The refund, net of the tax effect, has been added to 1965 net operating revenue and the applicable portions deducted from previous years incomes. The returns for 1961, 1962, 1963, and 1965 reflect this adjustment.

[e] Additional provision for depreciation reported as other interest expense is deducted from net operating revenue

[f] Formerly South Penn Power Co. Company acquired Cumberland Valley Electric Co. Aug. 31, 1964, through merger.

[g] Formerly Northern Virginia Power Co. [h] Formerly Potomac Light and Power Co.

[i] Formerly Western Light and Telephone Co., Inc. into which the former Western Power and Gas Co. was merged July 1, 1965. Return reflects full year operation of the acquired company.

[j] Company charges to depreciation expense an amount equivalent to the estimated reduction in Federal income taxes under section 167 of the 1954 Internal Revenue Code. The amount reported was for combined utilities.

Conclusion

The rate of return of electric utilities is calculated by the Federal Power Commission by dividing the net income by the rate base based on the original cost valuation.

The fair rate of return is a relative term not an absolute one. There are many factors to be considered in determining the rate of return. Such as the risk in business, the rate realized by similar enterprises. The attraction of capital. The maintenance of credit and the expansion of the utility. Two tests can be made about the fairness of the rate of return.

The first one is the cost of capital. This test shows whether the rate of return yields a fair return for the different groups of investors. With common stock, preferred stock or bonds.

The second test is whether the rate of return enables the company to obtain the replacement of bonds, and attract the necessary capital for expansion.

CHAPTER III

THE RATE STRUCTURES OF ELECTRIC UTILITIES

In the preceeding chapter, it was stated that the level of return should cover the operating expenses and yield a fair return to the investors.

In analyzing the total revenue in Chart No. 2, page 24, the total revenue was divided into the total revenue from ultimate consumers and revenue from sales for resale. The ultimate consumers were divided into groups such as residential, commercial, industrial, etc.

In this chapter the specific rate structures, that are determined to yield that level of return will be discussed. The fact that there is more than one rate schedule for electricity is due to two factors. The first factor is the difference in the cost of electricity consumed by different groups of consumers. This difference is due to a difference in load factors, off peak service, utilization and diversity factors. The second factor is the difference in the elasticity for the demand of electricity, which together with a separate market helps to create a price discrimination. A discussion of the cost and the demand of electricity follows.

Cost Analyses

In cost accounting there is an approach for determining the cost of a unit. This cost is determined by dividing the cost into three items; raw materials, labor, and overhead. Each of these items can be divided into direct and indirect costs. A direct cost on a unit of production is that cost which should be carried one hundred per cent by the unti of production. The indirect cost is that cost which does not belong to a certain unti, but is common to a group of units. If the cost of labor, material, and overhead were all direct costs, there would be no problem in determining the cost of a unit of production, but the difficulty is when there are indirect costs. In this case an arbitrary way of distributing the costs on the units of production should be found. The basis for division might be the hours of labor, or the hours of machinery work, or the value of the raw material spent in the production. The greater the diversity of the production on the hours of production the less the difference between the costs of the units of production.

In determining the cost of a unit of electricity the problem of the indirect costs appears. There are a lot of indirect costs and an approximation should be used in order to obtain the cost of a kwh of electricity. The situation of the indirect costs leads to what is called the joint costs, since the products which have a different production function could be called different products. Producing electricity by means of a steam production plant should have a different production function than producing it by a hydraulic production plant.

If the cost of a kwh could be determined with one hundred per cent accuracy this would still not solve the problem: since the idea in finding the cost of a unit of electricity is to determine the price of the unit that the consumer should be charged. Electric utilities have different groups of consumers with a large number in each group and there is no exact and practical way of determing the consumer who is consuming a specific kwh of electricity.

Determining the cost of kwh of electricity is hard and impractical in determining the rate structures of electricity. The best and practical approach would be <u>first</u>, dividing the production into plant costs, such as generating costs, transmission costs, distribution costs, and general costs, <u>second</u>, determining the factors that affect the costs of production, <u>third</u>, finding the relationship between these factors and the consumers groups, and <u>fourth</u>, reflecting the cost effects of these factors when determining the rate structures of the consumers groups.

<u>Generation costs</u>

The costs of producing electricity at the central plant is called the generation costs. If the production was evenly distributed per unit of time, then there would be no difference in the generation cost of a unit whether produced in the morning or in the evening. The details of the accounts included under the generation plant can be referred to in Chart No. 1, page 5.

Transmission costs

The transmission costs are the costs of carrying electricity at a high voltage from the generating station to the distribution centers which are known as substations. A group of consumers, that are at the same distance from the generating station, and that are using the current from substations, should have the same average cost per unit of current. The increase in the density of consumers caused a decrease in the average cost of electricity between the generating plant and the other locations.

Distribution costs

Distribution costs are the costs of distributing the current from the substation to the final consumer. These costs vary with the quantity of the current which flows through the wires. Doubling the quantity which is consumed might cut the distribution costs of a unit of electricity almost in half.

General costs

General costs are expenditures of the whole production. They are mainly the costs of the general plant, such as depreciation of the general plant, salaries, equipment, advertising, stationery, etc.

The second step in cost analysis would be the determination of the factors that affect the costs which follow:

The load factor

The peak load occurs only for a limited period, and during the off peak period part of the plant remains idle. The load factor is the relationship between the average load and the peak load. The Federal Power Commission publishes in the electric power statistics the peak load and the energy produced monthly by the electric companies in the United States. To find the load factor of an electric utility the average load and the peak load has to be known. The energy reported for Montana Power Company for November 1966 was 388,211,000 kwh and the peak load was 724,000.[1] To find the average load divide the energy produced by the hours of production in the month (24 x 30 = 840). The average load is $\frac{388,211,000}{840}$ = 459,800 and the load factor $\frac{459,800}{724,000}$ = .63

The load factor should be less than one because the average load is less than the peak load. When the load factor increases it makes a better utilization for the generators and decreases the average transmission and the distribution costs.

The utilization factor

The utilization factor is the relationship between the peak load and the maximum capacity of the system. The electric utility should have some surplus in capacity beyond the peak load because the peak load is not fixed

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[1]Federal Power Commission, Electric Power Statistics. Washington, D. C.: Federal Power Commission. 1966. p. 12.

and it changes. The utility should always be able to meet the demand of the consumers. If we suppose that the maximum capacity of Montana Power and Light was one million kwh then the utilization factor should be the peak load divided by the maximum capacity: $\frac{724,000}{1,000,000} = .724$. The utilization factor should be less than one because the peak load can not be more than the maximum capacity of the utility. A high utilization factor is desirable but it serves as a warning to the utility that the reserve capacity is declining, and that the utility should move to another scale of production if it wants to expand it's output.

The diversity factor

The diversity factor is the relationship between the sum of the maximum demand of all the consumers to the maximum demand at the generation plant. The sum of the maximum demands is always more than the maximum demand at the generation plant because the maximum demands of the different groups of consumers do not occur at the same time. The higher the diversity factor the better the utilization of the equipment of the utility is. To explain this, assume there are three groups of consumers having 3, 2 and 3 peak loads which are distributed over the 24 hours of the day so that no two of them demand electricity at the same time. The peak load at the generating station would be 3, the diversity factor would be $\frac{3 + 2 + 3}{3} = \frac{8}{3} = 2\ 2/3$.

On the other hand assume that all three consumers demand electricity at the same time. The peak load at the generation station would be: $3 + 2 + 3 = 8$ and the sum of the peaks of the consumer would be eight so the diver sity factor would be: $\frac{3 + 2 + 3}{3 + 2 + 3} = 1$.

In the first case when the diversity factor was 2 2/3, eight units were produced with a maximum capacity of three units. In the second case when the diversity factor was one, eight units were produced with a maximum capacity of eight. So a higher diversity factor means less capacity for the same amount of production but with less costs.

The relative importance of the cost factors

In the early days of introducing electricity the peak factors and the load factors were of importance in determining the rate structures. These two factors caused a difference in the rates of the domestic and the industrial users. The domestic demand comes at the peak period and has a very low load factor because the average load is low and the peak load is high. The cost considerations were that each group should cover besides its variable costs the fixed costs to supply the load it creates. The utilities often encourage off peak use by special rates. However, the diversity factor had lessened the importance of the peak load, because a higher diversity factor means better use of the capacity of the plant.

The cost factors mentioned are used as guides in setting the rate strucutres for the different groups of consumers. The ultimate analysis of the costs is to allocate the costs to consumers taking into consideration the load factors, the utilization factor, and the diversity factor. When the costs are allocated to the groups of consumers, the costs are divided into three types: service costs, demand costs, and commodity costs.

Service costs

Service costs are direct costs chargeable to the individual consumer, such as meter reading, billing, collecting, keeping of accounts, connections from the street to the meter, adjustment of appliances, and the like. These charges could be worked into the rate structure in a form of a minimum charge, or they could be included in some form of a unity charge. This can be explained by studying Utah Power and Light Company's rate schedule for residential service.

Monthly Bill
Rate
3.90 c per kwh first 60 kwh
2.80 c per kwh next 140 kwh
1.70 c per kwh next 200 kwh
1.65 per kwh all additional kwh
Minimum
$1.10 for single phase service
$3.30 for three phase service
Seasonal service:
When seasonal service is supplied under this schedule, the minimum seasonal charge will be $12.00.[2]

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[2] Utah Power and Light Co. Electric Rate Schedules and Electric Service Regulations. Salt Lake City, Utah: Public Service Commission of Utah. 1963. p. 1.

If the bill was 30 kwh or less than the charge would be \$1. 10 for the single phase service. The price per kwh is high in the first block so that the service costs can be covered if the quantity consumed is 30 kwh or more. If the quantity consumed is less than 30 kwh then the service costs are worked into the rate structure in the form of a minimum which is \$1. 10 for the single phase. The service costs do not have any relationship to the load or the utilization of the diversity factors and thus when the rates are made, these factors are not taken into consideration with relationship to the service costs.

Demand costs

What ever the size of the consumer demand of electricity might be, the utility must be ready at all times to serve him. The consumer may not require the use of the services for a period of time, but the company should be ready to serve him at anytime, and therefore the company should receive a return on the investment necessary for this service. Here the effect of the cost factors should be considered. The demand costs for a consumer whose demand occurs during the peak load of the generation plant is higher than the demand costs of a consumer whose demand occurs in the off peak period.

Commodity costs

The relationship between the per unit cost and the quantity consumed is what is intended by the commodity costs. The average cost per unit decreases when the quantity consumed increases. The important point is whether the increase in the quantity produced makes the producer move towards the short run optimum rate of output or beyond it. And whether the production has a decreasing or increasing long run average curve, the average cost of production. The following figure explains this concept.

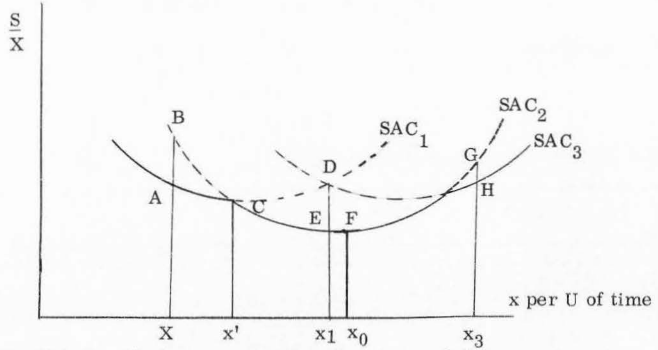

Figure 2. Relationship between the size of out put and the average cost.

In the above figure there are three short run average cost curves. The solid line represents the long run average cost. If an electric utility is producing an out put of x the average cost would be A on the short run average cost curve SAC. If the out put is increased to x^1 the commodity costs would decrease (average cost per unity) and it would be CX^1. If the out put expands to the point X_1 and the company can not expand its scale immediately the cost of the commodity would be DX_1 but if the utility increases its scale the average cost would decrease to EX_1. The Point F on SAC_2 at an out put of X_0 represents the minimum average cost, it is the point where the long run average cost curve is at its minimum and tangent to the short run average cost SAC_2. If the electric utility moves from this point the average cost increases. It was mentioned previously that costs should be allocated to the groups of consumers when working out the rate schedules. Yet the cost considerations are not the only factors in determining the rate structures of electric utilities. The value of the electricity which is reflected in the elasticity of demand should be taken into consideration when fixing the rates.

Demand Analysis

Frequently the difference in demand causes the difference in the rates of the regulated industries. The demand of a consumer is based on the price of the service, the utility that it gives him, his income, and the availability of substitutes. The consumer's demand is considered elastic when he has little need for the service, when he does not have the ability to pay for it, when he can provide it for himself, or buy it from a competing seller. The consumer's demand is relatively inelastic when he has no alternative source of supply or when his needs and ability to pay are great. Price discrimination may give the seller marked advantages. The seller intends to utilize his plant and maximize his profit. He will not practice discrimination if a single price can maximize his profit. But a price low enough to maintain full production may yield insufficient revenues to cover costs, while one set high enough to cover costs may result in unused capacity.

This situation makes the seller increase his revenues by charging a higher price where demand is inelastic and a lower price where demand is elastic.

> Price discrimination is frequently encountered in public utility industries. Electric power companies usually separate commercial from domestic users of electricity. Use of separate meter for each user enables the company to keep the markets apart. Elasticity of commercial users' demand for electricity is higher than that of domestic users; consequently, a lower rate is charged commercial users.[3]

The difference in prices charged for the same product could be shown by explaining the case of price discrimination and profit maximization under monopoly.

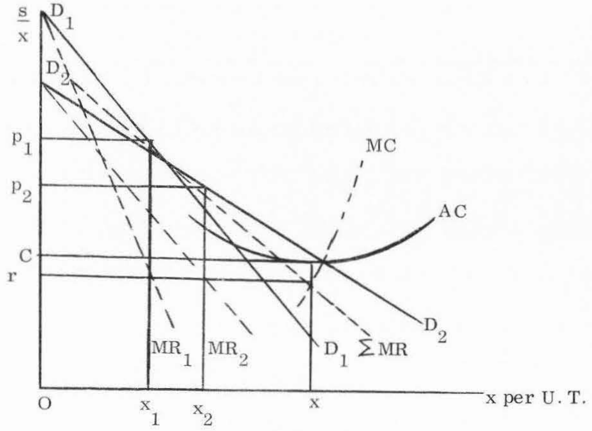

Figure 3. Monopoly and profit maximization.

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[3]Richard H. Leftwich. The Price System and Resource Allocation, New York: Holt, Rinehart and Winston, 1966), p. 199-200.

The monopolist's cost curves, together with the marginal revenue curve for his total sales volume, are needed to solve his profit-maximizing problem. Suppose that his average cost curve and his marginal cost curve are those of Figure 10. They are operative for his entire output regardless of how it is distributed. The marginal revenue curve for the entire sales volume when sales are properly distribured is Σ M R in Figure 10. The demand curve and marginal revenue curve for Market II have been drawn in the regular way. The $M R_1$ and $M R_2$ are summed horizontally to obtain Σ M R.

The profit-maximizing problem is reduced now to simple monopoly problem. The total output of the monopolist should be X at which Mc = Σ M R. The distribution of sales and the prices charged should be x_1 in Market I, sold at price p_1, and x_2 Marginal revenue in Market I equals marginal revenue in Market II equals r with this distribution of sales. If total output and sales were less than x marginal revenue in one market or the other (or both) would be greater than r marginal cost would be less than r. Increases in production up to x would increase profits. If total output and sales were expanded beyond x, marginal cost would exceed r and marginal revenue in one market or the other (or both) would be less than r. Such increases in production would add more to total costs than to total receipts and would decrease profits. With output x properly distributed between the two markets, profit in Market I will equal cp, x x_1, and profit in Market II will equal $cp_2 \times x_2$. Total profit will be $cp_1 \times x_1$ plus $cp_2 \times x_2$.

Rate Forms

The different rate schedules of the consumers were based on different rate forms. These rate forms were set to take into consideration the cost and the demand effects on the price of the electricity. Each group

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[4]Richard H. Leftwich. The Price System and Resource Allocation. New York: Holt, Rinehart and Winston. 1966. pp. 198-199.

of consumers might have a rate schedule based on a different rate form. The most familiar rate schedules for electric utilities are the following.

Block meter rates

Under this rate schedule the amounts of energy are divided into prescribed blocks with a different rate for each block. For example:

First 25 kwh or less	\$1.25
Next 25 kwh per month	4 cents per kwh
Next 50 kwh per month	3 cents per kwh
Excess	2 cents per kwh

This rate schedule takes care of the consumer costs by making a flat charge for the first kilowatt hour block or by making a minimum charge, even though nothing is consumed. The demand costs are covered in the higher blocks. The best feature of this schedule is that it is simple and easy to understand.

Wright demand rate

This rate schedule is known as the load factor rate. In this rate schedule the consumer is charged a higher price for his maximum demand and a lower price for the rest of his consumption. An example of this would be 4 cents per kilowatt hour for the first twenty-five hours per month at the maximum demand and 2 cents per kilowatt hour for any amount in excess of these twenty-five hours. With this type of rate the maximum demand for each consumer should be determined. It could be done by recording demand meter, or by estimation. This rate schedule is complicated and the consumer does not understand it.

Hopkinson rate

This type of a rate schedule has a separate charge for demand and a separate charge for energy. An example of this is:

Demand charge
First 5 kwh of demand at $3. 00 per kwh per month
Excess kwh of demand at $2. 00 per kwh per month plus an energy charge of
First 1, 000 kwh per month at 3 cents per kwh
Next 1, 000 kwh per month at 2 cents per kwh
Excess kwh per month at 1 cent per kwh

Other forms of rates

There are some other forms of rates, but they are of less significance than those which have been mentioned. Some of the other rates are straight line meter rate, flat rate and step rate. The flat rate, straight line meter rate, and step rate are not based on demand and cost analysis in determining the rate schedules. They were used in the past when the demand and cost analysis was not well developed and the groups of consumers were not very diversified.

Consumer Groups and Their Rate Schedules

Different rate schedules are set for different groups of consumers. Each group has in common similar cost and demand conditions. The load factor, the diversity factor, and the utilization factor should be considered when a rate schedule for a group of consumers is determined. Any rate schedule should cover the consumer costs, the demand costs, and the comodity costs, with consideration for the elasticity of demand for each group of consumers. The most important rate schedules are the following.

Residential rates

In this kind of rate schedules the first part of the schedule is determined to cover the consumer costs, such as the costs of the meter billing. The second part is a block type covering the demand and the energy costs. The third part covers the commodity costs. An analysis of the Utah Power and Light residential schedule mentioned on page 45, would explain the residential schedule. The first part of this rate schedule is a minimum charge of $1. 10 for single phase service or 3. 90 cents per kwh for the first 60 kwh. This first part is determined to cover the consumer costs, if his consumption was only zero kwh he should pay $1. 10 because of the costs of billing, reading the meter and other direct costs on the consumer. The second block is 2. 80 cents per kwh for the next 140 kwh. It is determined to cover the demand costs (in addition to the variable costs of the commodity). The electric utility can not charge the consumer costs and the demand costs in the first block of the rate schedule otherwise the price of electricity would be too high and this would discourage the consumption of it. If the consumer does not consume more than the units in the first block, a great deal of demand costs are not covered. Actually if it happened that some of the consumers were at the extreme in demanding a minimum out put, related to their group of consumers, it would be adjusted by the average behavior of the consumer whose demand would equal the expected amount of out put determined for his consumption. In the residential Utah Power and Light rate schedule for blocks, 1.70 cents per kwh and 1.65 cents per kwh, are determined mainly to include the commodity costs. Because the service costs and the demand costs are covered in the first two block of the rate schedule. These costs are close to the marginal costs because they cover the increase in the variable costs caused by increasing the out put.

Commerical rates

The commerical schedules are almost like the residential schedules. The difference is that the blocks of the commercial rates are designed to be several times the size of the residential schedules. In this kind of schedule special attention is given to the load factor, the diversity factor, and the utilization factor. An analysis for Utah Power and Light rate schedule no. 4 for commercial consumers explains the basis for determining this kind of rate schedule.

> Availability: At any point on the Company's interconnected system where there are facilities of adequate capacity.
>
> Application: This schedule is for alternating-current, controlled single-phase electric service supplied at not less than 240 volts through one kilowatt-hour meter at a single point of delivery exclusively for commercial and other non-residential storage water heating purposes. Service will be supplied by not less than seventeen hours per day, such hours to be specified by the Company and may be controlled by suitable device provided and maintained by the Company. This schedule is not applicable to space heating.
>
> Monthly bill:
>
> Rate:
>
> $2.15 for first 150 kwh or less
> 1.07 per kwh all additional kwh

Minimum
$2.15 [5]

Let it be assumed that the first block, which is the minimum charge, covers the whole consumer and demand costs. The next block which is 1.07 should mainly cover the commodity costs. If the consumption of a certain consumer was zero the consumer costs and the demand costs would be covered by $2.15. If the consumption of the consumer was 150 kwh or more than the $2.15 would cover the consumer costs, the demand costs, and the commodity costs. The commodity costs for the first block should almost equal the commodity costs in the second block which is 1.07 cents per kwh. The commodity costs for the first 150 kwh would be 150 x 1.07 = $1.605 cents. The residual would be $2.15 - $1.605 = $.545 for covering the demand costs and the consumer costs which are the minimum for these costs. The demand and consumer costs would be between $.545 and $2.15. But it should be noticed that the number of commericial consumers is not evenly distributed in this interval and it is likely to be biased in favor of $.545. The distribution would be more concentrated near the consumers with the 150 kwh demand or more. The other point, which is an important one is the application of this rate schedule.

". . . . Service will be supplied for not less than seventeen hours per day . . . ."

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[5] Utah Power and Light Company, p. 1.

This condition takes into consideration the load factor, the diversity factor, and the utilization factor. During the peak period the company might not provide the commercial consumers with electricity, this would increase the diversity factor because it decreases the peak load required for the company.

Power rates

Power rates are more difficult to set than residential and commercial rates. They should take into consideration; first, the consumer costs, the demand costs, and the commodity costs; second, the load factor; third, the elasticity of demand. To explain this the rate schedule of Utah Power and Light Company No. 9 will be analyzed.

> Application
>
> This schedule is for altering current, three phase electric service supplied at approximately 44,000 volts or higher through a single point of delivery for all service required on the customer's premises for manufacturing or other industrial purposes by industrial customers contracting for not less than 80 kwh seasonal service will be available only under other appropriate schedules.
>
> Monthly bill
>
> Rate
>
> \$2.00 per kwh first 100 kwh of demand
> \$1.90 per kwh next 200 kwh of demand
> \$1.63 per kwh all additional kwh
> .635 ¢ per kwh first 1,000,000 kwh
> .630 ¢ per kwh all additional kwh
>
> Power factor
>
> This rate is based on a consumer maintaining at the time of maximum use a power of 86 per cent lagging, or higher as determined by measurement. If the power factor is found to be less than 85 per cent lagging, the demand as recorded by the company's member will be increased by 3/4 or 1 per cent for every 1 per cent that the power facor is less than 85 per cent.

Minimum

The monthly demand charge, but not less than $160. 00

Demand

The kwh as shown by or computed for the readings of the companies demand meter for the 15 minute period of consumers use during the month, adjusted for power factor as specified, determined to the nearest kwh, but not less than 80 kw.[6]

This rate schedule is typically a Hopkinson rate schedule. It has a separate charge for demand and a separate charge for energy. This high charge for demand should cover the consumer costs and the demand costs. The demand cost is the more important factor in determining the demand charge. The utility should reserve a certain capacity for the industrial consumer, and he should be charged for reserving that capacity for him. In the case of the industrial consumers of Utah Power and Light Company the minimum capacity reserved is 80 kwh and the minimum demand charge is $160 a month. A power factor of less than 85 per cent is taken into consideration because a lower power factor means unsold electricity which is wasted because of the low power factor. This should increase the cost per unit of the final product. The industrial consumer who causes more losses than a certain level which is set at 85 per cent power factor should pay for this loss of electricity.

The energy charges per kwh in this schedule are low and it is very close to the marginal costs of the company. This is due to the relatively

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[6] Ibid.

elastic demand of electricity for the industrial consumer, because he could generate it for himself if the price is too high for him. The company would be willing to sell him the energy at any price that maximizes its profits and this price should be where the marginal cost equals the marginal revenue.

How Rates are Adjusted

Adjustments in rate schedules take place after submitting an application to the regulating commissions by a concerned party. The adjustment is then "a bit by bit change." A little may be chopped off of an existing schedule here, a little may be added there. One of the main duties of the utility commission is to see that there is no unjust discrimination, that is to see that each consumer has the same rate schedule which is applied to the group of consumers to which he belongs, between consumers and consumer groups. The detailed cost studies, for the average cost of kwh are hard, impractical, and expensive and are thus beyond the resources of the utilities and the commissions. The rate structures of electric utilities were developed historically, and adjustments have occurred when there was a need for adjustment. This was done by submitting an application for adjustment either by the company or by a concerned party.

The Effects of Regulation on Output and Price

The cost and the demand analysis, for the purpose of setting the rate structures of electric utilities, were explained in this chapter. Yet it should be noticed that it is not a one way road. Unless it is a case of constant costs the regulation of the price should effect the rate of output and consequently the cost per unit of production.

For an illustration a case of pricing under conditions of imperfect competition and decreasing cost will follow:

In this case a maximum price set below the monopoly price would benefit the consumers through both the lower price and the increased product output.

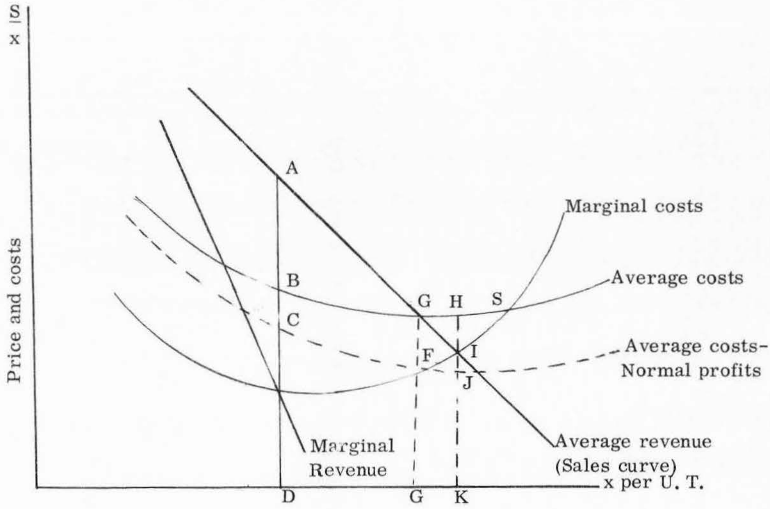

Figure 4. The effect of regulation on output and price.

Figure 4 represents an imperfect market in which the firm operates under conditions of decreasing costs. In the absence of regulation, the utility would maximize profits in the situation at output OD which corresponds with the point at which MR = MC. This represents the firm's equilibrium because the incremental cost (MC) for any unit of production beyond OD exceeds the incremental revenue (MR) expected from its sale. For any output short of OD the firm has not maximized profits since additional output in each instance would involve a marginal cost smaller than the corresponding marginal revenue. With production at OD, the unregulated firm would price according to its sales curve AD. Average costs exclusive of normal profit would be CD, average normal profit would be BC and the average abnormal profit would be AB.

If the firm is regulated at P = AC, in this instance (1) the total output would be increased to OG, (2) the regulated price would be EG which is less than AD, (3) the average cost minus normal profit would be FG, which is less than the unregulated average cost of CD, (4) the firm would enjoy average normal profit of EF which is greater than the unregulated normal profit of BC since such profits vary directly with the change in the volume of sales. If, instead of average cost pricing, the public utility commission attempts to follow the rule of marginal cost pricing production in Figure 3 would be I at which the sales curve AR intersects the marginal cost curve. In this situation output OK would be greater than OG, the output under average cost pricing and the rate charged to consumers, IK would be smaller. Although in this instance MC pricing will come closer to approximating the social optimum, it is important to note that the normal profits would only be IJ and not the full amount RJ required to keep the firm in business. In this case the government must subsidize the industry by the amount of HI on every unit of sales.[7]

Conclusion

The regulation of electric utilities is a difficult task. It involves the consideration of many variables to determine the rate base, the rate of return and the rate structures.

The determination of the rate base was very important in the past, many factors were considered in the determination of what is called the fair value. Among these factors are the original cost, the reproduction cost, the probably earnings of the utility, and the market prices of bonds and stocks.

The determination of the rate of return took less effort than the determination of the rate base. There are many factors which affect the rate of return. Among these factors are the return in the competing companies; the degree of risk involved in the company, and the current market interest rate.

The problem of determination of the fair rate of return and the fair value became less important after the Hope Gas case. According

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[7]Burton A. Kolb and Otis Lipstren. New Concepts and Current Issues In Public Utility Regulation - 214. Denver, Colorado: Peerless Publishing Company. 1963. p. 213.

to that case the "End Result" doctrine was the test for the fairness of the return. The "End Result" doctrine implies that the returns should be enough to maintain the credit position of the investor, to cover cost of capital, and to permit expansion of the utility.

The determination of the rate structure is the most important step, because the rate structures are the means by which the utility could realize the required level of earning according to the "End Results" doctrine, and because the rate structures determine the different prices which should be reasonable to the different group of consumers.

When determining the rate structures the cost factors such as the load factor, the utilization factor and the density factor should be taken in consideration. The elasticity of demand for electricity should be considered also in determining the rate structure. It should be noticed that as the costs determines to some extent the rate structures. The rate structures themselves have some effects in determining the cost of the regulated utilities, by determing the level of output produced at that rate structure.

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Master of Science

Thesis: The Electric Utilities Rate Structure

Major Field: Economics

Biographical Information:

Personal Data: Born in Nablus, Jordan, January 6, 1938.

Education: Attended elementary school and high school in Nablus, Jordan; received the Bachelor of Science degree in 1962 from Ain Shames University in Cairo, Egypt, major in accounting, with double minor in economics and business administration. Completed requirements for the Master of Science degree in economics at Utah State University in 1968.

Personal Experience: 1963 worked in the position of chief clerk in Nablus Municipality. Since 1964 worked as an accountant in the Agricultural Credit Corporation in Jordan.