Automatic Adjustment Clauses: Theory and Application
Automatic Adjustment Clauses
Automatic Adjustment Clauses: Theory and Application

by

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1980
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Division of Research
Graduate School of Business Administration
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to

Professor James E. Suelflow
Indiana University

A man whose support, encouragement, guidance, and friendship will be appreciated forevermore.

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The electric utility industry has recently experienced rather trying financial difficulties, jeopardizing its ability to attract new investment capital. This situation has been caused by abnormally high inflation (especially in fuel cost), a reduction in historic increases in productivity, the high cost of money, insufficient internal cash flow, and increasing investment requirements as a result of both load growth and construction cost increases. A primary factor influencing the tenuous financial status of the electric utility industry has been the delay in incorporating these rapidly rising costs into electric service rates.

Recognition that the present method for changing rates is expensive and time consuming and often lags behind economic conditions has resulted in public policies that go beyond the traditional method of rate regulation in order to satisfy statutory responsibilities. One of the more practical solutions has been the use of automatic adjustment clauses.

The purpose of this study is to examine the historical and current application of automatic adjustment clauses in electric utility tariffs as an alternative to traditional ratemaking. My task is now complete, and its success or failure is in the hands of the reader. No book is solely the product of its author, however, and, although any shortcomings the reader may find are my own responsibility, the work positively benefits from careful and time-consuming input from a number of highly qualified individuals in academia, government, and the electric utility industry.

The early portion of the work was completed as part of my doc-
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Mr. C. Burton Nelson, former commissioner and chairman of the Illinois Commerce Commission. His helpful insights on the service-at-cost and managerial portions of the study were invaluable. All of these individuals deserve to share in the success of this work, and it is unfortunate that they are no longer a part of the regulatory community.

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A significant portion of this study was completed during my tenure as manager of the Policy Analysis and Research Division of the Illinois Commerce Commission. From a regulatory perspective, I was able to investigate many of the issues surrounding automatic adjustment clauses as well as to obtain the help and guidance of colleagues at the commission whose knowledge on these matters is second to none. I would especially like to thank Charles P. Kocoras, former chairman of the Illinois Commerce Commission, for his dedication to the staff investigation into the fuel adjustment clause. His insistence that all the issues be brought into the open and thoroughly investigated provided a great deal of material for this work. I would also like to thank Mr. C. Wayne Fox, former manager of the Public Utility Division, for his help in a number of technical aspects associated with fuel adjustment clauses. Mr. Fox, along with Robert Lane, former supervisor of the Electric Section, and Neill Demmick, the commission's chief accountant, reviewed and commented upon each of the problem areas. Their input was critical in the composition of that portion of the study, and without their contributions the end result would not have been achieved. Finally, I would like to thank...
Consumers paid $13.4 billion more for electricity and natural gas in 1977 than in 1976. That annual increase is an all-time high. This conclusion was reached in a recently released U.S. government report entitled Electric and Gas Utilities Rate and Fuel Adjustment Clause Increases, 1977. The report states that electric utilities accounted for about 65 percent of the increase, gas utilities for 35 percent. During the last four years, electric and gas increases have amounted to $48.3 billion, an average of more than $12 billion a year. This contrasts with the period 1948 to 1973, when electric and gas utility rates increased only $6 million. Thus, currently, the average increase every six months in utility bills equals the increase for the entire quarter-century ending in 1973.

Fuel adjustment clauses account for ever larger percentages of the total increases. These clauses for both gas and electric provided 58 percent of the increases in 1974 and 1975, 76 percent in 1976, and 82 percent in 1977. Of the $13.4 billion increase in 1977, $11 billion was due to the fuel adjustment clause, and a "mere" $2.4 billion resulted from rate increases due to formal rate proceedings.

Automatic Adjustment

An adjustment clause is a tariff provision, approved in advance by the regulatory commission, in which a change in a preselected cost item or items will automatically permit a change in the price consumers are charged for service, without the delay and expense of a formal regulatory hearing. Faced with unprecedented price increases, consumer reaction to fuel cost recovery through automatic
adjustment has not been passive. The fuel clause has come under considerable public protest due to its magnitude, real and potential abuses by utilities, and rapid widespread application. The public is becoming convinced that automatic adjustment clauses are moneymakers for utilities, coal companies, and oil and natural gas producers. The intensity of consumer reaction to the magnitude of the costs passed on to them automatically by the fuel adjustment clause has been expressed in increased consumer presence at rate hearings, letters to commissioners and staff, and political pressure in state legislatures and Congress. Perhaps Ms. Ollie Baker of the Chicago consumer group Metro Seniors in Action summed up consumer reaction best by referring to the clauses as "Santa Clauses for the power companies." The late Senator Lee Metcalf, during congressional debate on the topic, referred to the FAC as a "fool adjustment clause."

The automatic adjustment clause can act as a two-edged sword. The clauses also pass cost savings forward to the consumer, allowing them to enjoy a reduction in price when the cost of the item subject to automatic adjustment falls. Furthermore, automatic adjustment, under certain circumstances, can work against the utility. For example, if sales fall off the utility need not operate higher cost plants, although the cost of operating such plants is built into its base rates. Thus, per unit (kwh) prices are higher than costs would dictate. With the fuel clause in effect, however, the savings from not operating the higher cost plant are passed on to the consumer.

Purpose
The purpose of this study is to examine the historical and current use of automatic adjustment clauses to augment traditional ratemaking in electric utility tariffs. The first segment of the study deals with regulatory lag and its positive and negative aspects. The legal and economic constraints under which the regulatory agency and the regulated firm must operate are examined.

The second portion of the study deals with the automatic adjustment clause as a regulatory tool for mitigating the negative effect of regulatory lag. This review examines historical methodology, application, and development of various automatic adjustment mechanisms. Specific criticisms and suggestions are included where applicable.

The final section of the study examines current problems in automatic adjustment clauses and deals with current applications of comprehensive automatic adjustment as well as problems in electric fuel adjustment clauses in the context of the requirements of the National Energy Act (Public Utility Regulatory Policies Act, Sec. 115). The discussion specifically examines fuel adjustment clauses in the states of Ohio, North Carolina, and Connecticut.
The electric and gas utility industries currently face unprecedented challenges in cost increases as well as capital investment. With the passage of the National Energy Act, in combination with historic increases in the wellhead price, gas utilities will face atypical price increases for the foreseeable future. The electric utilities have faced similar cost increases in fossil fuels as a result of the Arab oil embargo, changes in environmental requirements, changes in coal mining practices, and use of low sulfur coal.

Periods of rising costs are not unusual for the utility industry, but during the 1950s and early 1960s, when inflation rates of 4 percent or less were prevalent, the industry was generally able to offset rising costs through productivity increases, technological improvement, and increased scale economies. Recently, however, these offsetting factors have leveled off, and when combined with double-digit inflation, especially in fuel costs, the industry’s earning performance has been handicapped. As a result, electric and natural gas utility stock prices have plunged, more so than in other industries, often resulting in market prices substantially below book value.

A primary factor influencing the financial status of the utility industry has been the delays encountered in demonstrating the need for rate relief before the regulatory agencies. This delay has traditionally been referred to as “regulatory lag.” An examination of the basic theoretical as well as practical aspects of regulatory lag and its positive and detrimental effects during changes in economic conditions follows.

### Rigid Rate Level

The solutions to the economic and financial difficulties experienced by utilities are often complicated by the regulatory environment in which the industry must operate. A basic problem is the reconciliation of a static or fixed rate level to the pressures and demands of a dynamic or changing economy. Rate level is defined as the total amount of revenues the utility is allowed to collect from the rate payers for a given amount of service. Although windfall in nature during periods of high gains in productivity and/or cost decreases, a static rate level results in economic hardship to the utility when cost increases outstrip productivity gains.

The procedure for setting a rate level in a formal rate case is time consuming and allows little or no flexibility to change rates until the next rate hearing. The procedure is as follows. (1) A “rate base” is found, that is, the investment in the firm, usually the original installed cost of plant used and useful (plant under construction is excluded), less depreciation, in serving the public. (2) A competitive rate of return that should be allowed on that investment is determined sufficient to attract and maintain investment capital. (3) That rate of return is applied to the rate base, providing the dollar amount that may be earned to satisfy capital holders (both debt and equity). (4) The prices to be charged for the utility’s services are then set at a level which is expected to yield that dollar amount of return after all other allowed expenses associated with doing business, including depreciation and income taxes, are met.

These requirements can be shown more succinctly by the cost of service model:

\[
RR = E + d + t + (V-D)R, \tag{1.1}
\]

where:
- \( RR \) = revenue requirements or total revenues the regulated firm is allowed to collect for its services (total cost of service);
- \( E \) = allowed operating expenses;
- \( d \) = depreciation expense for the current year;
- \( t \) = taxes, including local property taxes and state and federal income taxes;
- \( V \) = gross valuation of the utility’s plant investment, including an allowance for working capital;
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\[ D = \text{accumulated depreciation of the firm's plant investment}; \]
\[ (V-D) = \text{net valuation or rate base}; \]
\[ R = \text{the allowed rate of return (usually includes aspects of the weighted average cost of embedded and current debt, preferred stock, and after-tax cost of existing equity at current market value)}; \]
\[ (V-D) R = \text{return amount, or earnings allowed on the rate base}. \]

Inherent in the above formulation is the problem of determining the proper competitive (no monopoly or economic profit) level of return \( R \) that should be allowed.

The Proper Rate of Return

For nearly fifty years, regulators, the courts, and the utilities themselves have debated the question of the proper rate of return for the utility enterprise. Pragmatic agreement on the determination of a rate base has diminished the previously controversial aspects of the value of utility property. The contractual feature of the return to bondholders and preferred stockholders reduces argument on the allowed rate of return to these investors to minor significance. However, substantial debate remains on the determination of the rate of return to be granted common stockholders. The bulk of this debate concerns the risk premium to be allowed and its determination.

The Role of Risk

Utilities and other business firms are similarly influenced by the capital markets' appraisal of risk. For any type of firm, risk enters into the markets' appraisal of the value of existing or proposed securities, the firm's decisions regarding its capital structure, and the firm's appraisal of individual investments, alternative production techniques, and so forth. The markets' reaction to these factors forms the basis for the cost of capital to the firm and the regulatory response in setting the allowed rate of return.

For the regulated sector, risk takes on additional significance. Several decisions by the U.S. Supreme Court as well as state and federal commission rulings have specified guidelines for utility regulation — namely, that revenues be sufficient to cover operating expenses as well as the capital costs of doing business, including a return to the investor commensurate with the associated risks. Two such cases were the Bluefield Waterworks case in 1923 and the Hope Natural Gas case in 1944.

In the Bluefield Waterworks case the Supreme Court held that "a public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties." Twenty years later, in its decision in the Hope Natural Gas case, the Court repeated this position. "From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks." Risk in both cases was generally interpreted to mean low, uncertain, or irregular net income to the firm.

The current financial instability in the electric utility industry raises doubt as to whether the traditional regulatory process has been responsive in meeting the specifications of the above guidelines. The traditional process is time consuming and expensive. Combined with and as a response to rising expenses and capital costs, the utilities and commissions are confronted with the dismal prospect of repeated applications for rate adjustments and hearings thereon. Inherent in this process is the problem of regulatory lag, the time that often transpires between the change in costs and the authorization granted to recoup them.

The Problem of Regulatory Lag

The crux of the regulatory lag problem is that rates are approved by the regulatory commission based on the expenses and capitalization of the firm during a "test year," usually twelve months of historical cost data. Thus, operating expenses, depreciation, federal, state, and other taxes (less any tax credits), plus an allowed return on invested capital, are determined from past capital and production costs. The whole procedure is admittedly backward looking in that the
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earned rate of return in the test year is compared with the current allowed rate of return (based on an appraisal of capital market conditions), and prices are adjusted so that the rate of return which would have been earned during the test year equals that allowed. Although the Federal Energy Regulatory Commission (FERC) now allows use of a "projected test year" based on anticipated costs for rate making under its jurisdiction, very few states prefer this method for retail ratemaking.

Consequently, future rates are made on the basis of past costs, and if rates are not adjusted promptly and continuously to cover cost increases, the shortfall must come out of common share earnings. For example, in 1979 the average time lapse between filing a rate request application and a decision was nine to ten months. Thus, even if the utility received all of the requested rate increase, it would be based on data at least ten months old. With an annual inflation rate in excess of 10 percent, the costs which necessitated the rate request would have increased at least 8.33 percent during those ten months, forcing the utility to absorb those costs and to file another request for the increase accumulated during the ten-month lag. In some states rate increases have lagged behind cost increases by as long as three years.

Effect of Regulatory Lag

Regulatory lag has been and continues to be a useful tool of the regulatory process as an incentive for more cost-effective or efficient management. This fact was pointed out by Alfred Kahn: "Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their opposites; companies can for a time keep the higher profits they reap from a superior performance and have to suffer the losses from a poor one." Thus, regulatory lag can serve as a deterrent to waste and inefficiency. The lag forces management to take a careful look at the expenditures made for a given level of sales and a given set of prices. The lack of immediate recovery (or no recovery at all if the expenditure is not incorporated into the test year) serves as an incentive for prudence and prevention of inappropriate expenditures. In this way regulatory lag helps the regulator simulate competitive conditions in the monopolistic utility industry by providing the monopolist with an incentive to keep costs down, as though the utility were competing with an infinite number of competitors who were also trying to reduce costs.

In view of the current financial condition and capital needs of the electric power industry, combined with rapid inflation, there is considerable evidence of increasing concern in the regulatory community for the burden imposed by regulatory lag. Underlying this concern is the recognition that a continuation of regulatory lag will eventually cause an adverse impact on service quality and quantity, risk, and price of service to the consumer.

The penalty of risk from regulatory lag was pointed out by Paul J. Garfield and Wallace F. Lovejoy: "Regulation itself, in conjunction with long-term inflation may create risk. The regulatory process is slow and meticulous. If a utility is faced with rapidly rising operating costs, it ordinarily cannot without commission approval increase rates to provide additional revenue to meet the rising costs." Charles Phillips came to a similar conclusion: "Regulatory delay adversely affects the public welfare in several ways. Delay in the regulatory process may hamper the progress and efficiency of the regulated industries. . . . Delay may postpone or even deny justice." In an attempt to avoid the problems associated with regulatory lag, utilities have been forced at considerable expense to file more frequently. A typical retail rate case for a medium to large utility costs about $300,000 to $500,000 in out-of-pocket costs and probably double that amount when company fixed expenses such as staff salaries are included. Indeed, it has not been uncommon for a utility to find itself preparing for its second (or third) filing prior to receiving a decision on its previous request.

These burdens on both the utilities and the regulatory agencies have led to policies that deviate from historical ratemaking techniques. A pragmatic although controversial approach has been the use of automatic adjustment clauses.
Automatic adjustment is and should continue to be a deviation from formal ratemaking techniques. It is strictly a policy option of the regulatory commission to ease unnecessary administrative burdens and to prevent financial jeopardy of the utility during adverse economic conditions. Automatic adjustment must be a privilege granted by the regulatory agency, not a right to which the utility is entitled.

The intent of this chapter is to outline the nature and purpose of automatic adjustment, to discuss its advantages and disadvantages, and to describe briefly the types of adjustment clauses now in use.

Definition

An automatic adjustment clause is a tariff provision, approved in advance by a regulatory commission, in which a change in a preselected cost item or items will automatically permit a change in the price charged consumers, without the delay and expense of a formal regulatory hearing.

The automatic adjustment clause is an agreement sanctioned by the regulatory commission in advance that becomes a fixed rule under which the future rates to be charged the public are determined. It is simply an addition of a mathematical formula to the company's filed schedules under which the rates and charges fluctuate, as costs to the company fluctuate.

Purpose

The purpose of an automatic adjustment clause is to allow a utility to adjust its revenues to accommodate changes in actual costs for a major expense item(s) over which it generally has little or no control. The objective is to mitigate the effect of relatively volatile cost items the firm purchases on a continuous basis. Prime examples are coal in the case of electric utilities and purchased gas for natural gas distribution companies.

When this strict purpose is followed, the automatic adjustment clause is not a substitute for a formal rate case. It is only an interim measure that functions between rate cases, adjusting for cost changes which continually occur in the marketplace. It is not a mechanism to preserve the company's allowed rate of return but serves only to mitigate the effect on the rate of return of any cost changes in certain preselected items.

Therefore, the automatic adjustment clause by its nature cannot increase the utility's allowed rate of return. Again, its primary intent is to compensate for fluctuation in a segment of total cost so as to neutralize the effect on the rate of return, restoring rates closer to the cost of service.

Advantages and Disadvantages

There are certain advantages to automatic adjustment clauses. Among these are:

1. The clauses allow utilities to recover increases in costs over which the firm generally has little or no control.
2. They allow the utility to recover the cost increase automatically without filing a major rate case, thus easing administrative burden and reducing both the company's and the state's regulatory costs — savings that are passed on to the consumer/taxpayer.
3. They operate swiftly, reducing regulatory lag and thus protecting the utility's ability to raise new investment capital.
4. They prohibit an excessive rate of return generated by rates when costs were higher; that is, they pass savings forward to the consumer. (The clauses also pass forward rebates or litigation settlements utilities gain from suppliers.)

Adjustment clauses also clearly have certain drawbacks.

1. Recovery of increased cost for one item may ignore compensating or offsetting savings for economies realized elsewhere in the business through improved technology, labor productivity, and/or operating efficiency.
Automatic Adjustment Clauses

2. By allowing quick and easy recovery of a particular cost item such as fuel, automatic adjustment may reduce the company's incentive for efficient management operation and/or may discourage hard bargaining in fuel contract negotiations.

3. Adjustment clauses remove one or more of the risks of doing business from a company that is rewarded for taking risks; in other words, utilities have risks just like nonregulated companies that must survive through innovation, efficiency, and good management. To the extent adjustment clauses dampen efficiency and innovation, the public interest is not being served best, and the concept of a utility company as a private enterprise is eroded.

Current Use

A number of automatic adjustment clauses are now in widespread use. These compensate for such items as increased expenditures for fuel, pollution control equipment, tax increases, and cost of debt and equity capital. Other adjustment clauses have been instituted for pass-through of cost changes in wages and price-level inflation. In 1973, the New Jersey Board of Public Utility Commissioners approved a comprehensive service-at-cost adjustment clause for the telephone industry that permitted automatic rate increases whenever the rate of return fell below the allowed rate of return due to increases in wages and salaries, all other expenses, and taxes. The plan was discontinued in 1975. The New Mexico Public Service Commission approved a similar clause for an electric utility in its jurisdiction in 1975.

The current interest shown in automatic adjustment clauses is based on the premise that their use will result in fewer formal rate cases and lower capital costs, and will provide a closer relationship between cost and price. The basis for lower capital cost is dependent on a reduction in risk as defined earlier. Throughout the United States, however, legislative and regulatory bodies recently have been taking a critical look at the operation of utility fuel adjustment clauses. There are two primary reasons for this close scrutiny: the sheer magnitude of the costs being passed through the automatic adjustment clause, often with minimal review by the regulatory agencies; and criticism that utilities have few incentives to minimize and control fuel related costs and that these costs can be recovered with minimum delay through automatic adjustment.

Types to Be Considered

The remainder of this discussion considers three general types of automatic adjustment: sliding scale, service at cost, and adjustments based on changes in operating costs such as fuel, wages, taxes, and so forth. A critical analysis of the methodology of each is included in search of historical solutions to many of the same problems associated with the automatic adjustment clause today. The analysis concludes with specific recommendations for modifications in methodology.

The first adjustment to be considered is the sliding scale, which was not an adjustment clause in the sense defined earlier. It was a methodology for adjusting electric service rates in response to cost changes. In its historic form, the sliding-scale system of regulation was a way in which management efficiency was rewarded by allowing a higher rate of return if the price of service to the consumer was falling, and management inefficiency was penalized by allowing a lower rate of return if price of service was rising. Generally, after a normal return on the rate base was established, above average earnings of a given year were retained by the firm that year, but prices were reduced sufficiently to eliminate a prespecified portion of the excess the following year. Conversely, if earnings fell below normal, rates were increased to restore a prespecified portion of the normal return. The sliding scale is included here because this particular incentive methodology has been useful in modifying other adjustment clauses to encourage management efficiency.

The second methodology considered is the service-at-cost or comprehensive automatic adjustment clause. The service-at-cost method of regulation is essentially a cost-plus contract between the utility and the consumer, subject to regulatory approval and tied to the cost-of-service formula described earlier in Equation 1.1. The concept involves agreement in advance upon such matters as the rate base, the rate of return, depreciation, disposition of surplus earnings, financial policies, operating expenses, as well as other pertinent matters. In practice, as any of its costs vary, the utility is allowed to adjust its rates automatically to compensate, without a formal rate hearing.

The final type of automatic adjustment clause to be considered is a provision that, again without formal proceedings, increases or decreases utility rates in direct proportion to increases or decreases in only certain preselected operating expenses. The most common of such provisions is the fuel adjustment clause (FAC) now prevalent in
most electric and gas utility rate schedules. By this provision, the energy charge to the consumer is increased or decreased by a fixed amount for each increase or decrease over or under a predefined base cost per unit of coal, natural gas, or other fuel used in production. Although other operating adjustment clauses are discussed, most of the emphasis is placed on the fuel clause.

Historical Development of Automatic Adjustment Clauses

The purpose of this chapter is to provide a review and analysis of the historical background of automatic adjustment clauses. The results of the discussion are used later to relate the historical problems associated with the automatic adjustment clause (AAC) to many of the same problems facing regulatory agencies, consumers, and electric utilities today.

Three general types of automatic adjustment are considered: the sliding-scale plan, the service-at-cost plan, and adjustments based on changes in operating costs, primarily fuel. The discussion is limited mainly to the electric power industry, although automatic adjustments are common in the natural gas industry and occur to a limited extent in other regulated industries.

Sliding-Scale Plans

Adjustments based on a sliding scale were designed to reward a firm for its efficiency (measured by reductions in the price of service to the consumer) by allowing greater profit margins.

Historical Development

The sliding-scale principle originated in Great Britain as part of the Sheffield Gas Act approved by Parliament in 1855. According to the act's provisions, the Sheffield Company, a supplier of manufactured gas for lighting, "was permitted . . . a dividend of 8% as long as the price of gas was over $0.84 per mcf, but could declare a 10% dividend when the price was $0.94 or less." In 1893, a similar plan was introduced to Great Britain's electric power industry. However,
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both plans were terminated during World War I as a result of rising costs caused by high rates of inflation. Inflation was a malady common to the sliding scale for reasons to be discussed shortly.

On 29 May 1906, Massachusetts enacted legislation entitled, “An Act to Permit the Reduction of the Price of Gas in the City of Boston,” commonly referred to as the Boston Plan. The plan contained a standard sliding-scale arrangement, and prices fell briefly from 1908 to 1917, but rose sharply thereafter. As in the Sheffield Plan, inflation was the primary cause.

Another factor weakened the Boston Plan even further. The Boston Consolidated Gas Company, to which the legislation applied, was a subsidiary of a holding company. Under this corporate arrangement, the holding company generally collected not only the profits of the subsidiary, but also various charges to the subsidiary for services such as engineering studies, rate work, and so forth. Since the holding company was unregulated there was no control over the prices it charged the subsidiary for its services. Therefore, these prices could escape regulatory scrutiny and, in time, become part of the subsidiary’s cost of service and, thus, an allowable expense under the plan. As a consequence, the holding company could choose to siphon off profit in the form of excess service fees instead of striving for cost reductions to trigger the higher return under the sliding scale.

The plan was investigated in 1915, and its discontinuance was recommended but no action taken. The plan continued in effect until 1926, but it was finally repealed due to rising prices ($1.35 per mcf in 1920) and further investigation of holding company abuses by legislative action taken in 1925.

The sliding scale was first applied to the electric power industry in the United States as part of a municipal franchise granted to the Dallas Power and Light Company on 1 October 1917. The Dallas Plan provided for the following: "For each of the first four half-cent reductions in the ... price of energy the company’s allowable return was subject to an increase of one-half of one percent. Further reductions of half a cent each in the ... price authorized an increase of one-quarter of one percent in the return for each such reduction." From 1 October 1917 to 1 January 1919 the straight-line rate charged by Dallas Power and Light was 7 cents per kwh, allowing an 8 percent return. From 1919 to 1931 the rate was 6 cents with a 9 percent return. However, a portion of these price reductions may have been due to productivity increases outside the company’s control. Another weakness of the sliding scale to be discussed shortly. Perhaps partially as a result of external productivity benefits, the straight-line rate was reduced in 1932. In 1934, the rate of return was frozen, and the plan was abolished in response to public displeasure with the high rates of return allowed (reaching 16.6 percent in 1931) and the lack of regulatory supervision.

Similar sliding-scale plans were introduced in Connersville, Indiana (1917–1920), Memphis, Tennessee (1924–1926), and Houston, Texas (1915–1934). The Houston Plan added a modification that permitted an unlimited return, but any excess over 8 percent was divided equally between the company and its customers. This same idea was incorporated into the plan adopted by the Detroit Common Council in 1935 for control and disposition of excess earnings of the Detroit City Gas Company.

The Detroit Plan was a disappointment from the start. It provided for the first $550,000 in excess earnings to be divided equally between the company and its customers, and for 75 percent of the excess earnings beyond that amount to go to the consumer. Only one such refund was paid, in late 1937. Cost, valuation, and auditing procedures were not adequately established. Moreover, changes in the base return were not sufficiently defined, and controls over operating expenses were not provided.

The plan continued in effect for two years, although there was no documentation of substantial customer benefits during that time. Following an investigation of Detroit City Gas rates by the Michigan Public Utilities Commission, the question of the legal status of the plan was carried to the Michigan Supreme Court. The court decided that the plan was invalid because it was not part of a valid franchise and that the city could either formulate a valid one or relinquish control to the Michigan Public Utilities Commission. The city chose the latter alternative.

Problems

The lack of longevity in each of the above sliding-scale plans appears to be due to one of several inherent weaknesses, including inflation, holding company abuses, rigid rates of return prescribed as part of the formula, gains from productivity increases beyond the company’s control, valuation of plant, and (perhaps a key factor overlooked by the plans’ creators) price elasticity and shifts in demand.
Inflation was the primary reason given for discontinuing most of the sliding-scale adjustments. The purpose of the adjustments was to reward price decreases. Yet, if cost of service legitimately rose, there was no mechanism to segregate and adjust for increases beyond the company's direct control. In contrast, the firm could benefit from productivity increases external to the firm and/or increases in sales (outward shifts in demand for electric service). Due to the declining average cost curves (due primarily to technological changes external to the firm) faced by these "natural monopolies," increases in sales resulted in a lower cost per unit—allowing a lower price and triggering the benefits of the sliding scale. In this case the customer provided the "effort" and the company collected the reward.

The fixed rate of return provided in many of the formulas penalized the firm when capital costs rose. By the same token, the company received a windfall gain when capital costs fell. The same result occurred if the firm changed its capital structure through leverage. Perhaps, and no proof will be offered here, management enjoyed the benefits of the plan as operating costs or cost of capital fell, but quickly abandoned the idea when the cycle was reversed.

In addition, the holding company, of which many electric and gas firms were a part, could siphon off profit in the form of excessive service fees when the benefit of the fee exceeded the benefit from the reward gained through price reductions. Perhaps, and no proof will be offered here, management enjoyed the benefits of the plan as operating costs or cost of capital fell, but quickly abandoned the idea when the cycle was reversed.

Valuation of plant, a significant problem in early regulatory history, compounded itself in the sliding-scale plan. Since the rate of return increased if price of service was falling, a higher rate base would bring a higher return amount. Therefore, an error in valuation would abnormally reward or penalize management performance. Furthermore, management could compare the benefits of a high valued rate base, which would contribute to higher rates but perhaps a lower return, to the benefits of a lower valued rate base, which would contribute to lower rates but trigger a higher return through the sliding scale. Such trade-offs could offset the regulatory intent of stimulating efficiency.

Finally, the sliding-scale plan appears to ignore demand elasticity as well as shifts in demand for electric service. An elastic (elasticity greater than one) demand for electric service would frustrate the operation of the plan since a decline in price would increase sales.

Historical Development

Even in the absence of a sliding scale, such an increase improves profits (under declining cost conditions), but, with the plan, the high rate of return would be unjustifiably invoked. A positive shift in demand would have a similar effect.

An opposite effect occurs if demand shifts in a negative direction. Such a shift causes the firm to operate at a higher point on its average cost curve. Although regulation would allow prices to be adjusted upward, the higher prices would be coupled with the lower rate of return.

Each of the above factors alone or in combination affected the results of the sliding-scale experiment in a negative way. However, one plan did survive and served for over 30 years. This was the well-known Washington Plan. In light of the problems inherent with sliding scales, how was this particular plan able to survive?

The Washington Plan

The best known and most long-lived sliding-scale plan was the District of Columbia's Washington Plan, conceived in 1913 when Congress slipped in "a modest little paragraph authorizing the commission to approve of a sliding-scale arrangement" as part of the act creating a public utilities commission for the District. The idea was dormant from 1917 to 1924 because of litigation between the commission and the Potomac Electric Power Company over the value of PEPCO's rate base. The valuation problem was settled in a Consent decree on 31 December 1924, and the plan was put into effect in 1925.

The plan involved the agreed upon rate base that was to be adjusted for additions and extensions at original installed cost. A formula was established to keep accumulated depreciation within 15 to 20 percent of the rate base. The rate of return mechanism differed from the sliding scales previously discussed. Initially, PEPCO was allowed a basic rate of return of 7.5 percent. If the return for the year exceeded this figure, the rate schedule for the following year was altered to reduce the excess by 50 percent. Conversely, if the return fell below 7.5 percent for specified time periods, rates would automatically be adjusted upward to restore the basic return. Nothing was said about changes in the price of service to the consumer as in previous sliding-scale applications. Consequently, the plan could survive during periods of inflation since, regardless of cost increases, the 7.5 percent return rate would be restored.
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To avoid the problems associated with a rigid rate of return, provision was made for the allowed rate of return to be modified. It was reduced to 7 percent in 1933, with further reductions to 6.5 percent in 1935 and 6 percent in 1938. In 1948, the plan was revised such that one-half of the income in excess of the basic return of 5.5 percent was to be held in a deferred credit account; withdrawals from this account and a credit to income were to be made whenever operating income fell below the basic return.23

Under the plan, electric service rates fell from $0.702 for 100 kwh in 1925 to $0.256 in 1942 compared to an average reduction from $6.00 to $3.80 in all cities of more than 50,000 population. Financially, the company earned an average of 14.44 percent on common stock equity over the same period.23 This is in contrast to an average of 5.2 percent for all Class A and B investor-owned electric utilities.24 These figures demonstrate that management was stimulated by the plan toward greater internal efficiency than other electric firms. Both company and consumer benefited—the former received an abnormally high return on equity, the latter abnormally low prices. However, the plan suffered from several weaknesses that led to its abandonment in 1955.

Primarily, the problems inherent in demand elasticity and/or shifts in demand were not adequately provided for. While the plan was in effect, the firm operated under generally falling average and marginal cost curves, allowing it to enjoy improved returns due simply to increases in sales. There was no adjustment mechanism to incorporate changes in price due to shifts or changes in demand, a problem discussed previously.

Although the flexibility in adjusting the basic rate of return was a redeeming factor, the adjustment mechanism for inflation was a serious shortcoming. By assuming a minimum base return (initially at 7.5 percent) during periods of inflation, the firm received the benefits of a cost-plus contract. In retrospect, this provision may have contributed to the longevity of the plan in contrast to others, but the guaranteed return contributed little incentive toward efficiency.

Furthermore, during periods of rapid inflation, strong efforts may have been made within the firm to hold costs down. Under the plan, there was no mechanism to reward such efforts. Thus, although deflation gave the firm an increased but essentially unearned return, cost increases that were equal to or exceeded productivity gains both eliminated any reward and made price reduction impractical.25

Finally, the sliding-scale mechanism may have violated the regulatory constraint as depicted in Equation 1.1. Assuming the minimum allowed return was a competitive one, by allowing a higher return (when prices were falling) the sliding scale caused rates to exceed "competitive levels." In effect, this regulatory mechanism did not explicitly provide competitive market pressures but allowed a higher than competitive return.

Service-at-Cost Plans

The service-at-cost or comprehensive adjustment differs in intent from the sliding-scale plan. In practice this plan is designed to act as a cost-plus contract between the utility and the consumer, subject to prior regulatory approval. Thus, the utility is assured that as any cost items vary, service price will be allowed to vary in direct proportion.

Early History

Service at cost was first used by Consumers' Gas Company of Toronto, Canada, in 1887. A reserve fund, consisting of $1 million in premiums from the sale of stock, was established as the nucleus to trigger the adjustment mechanism. Withdrawals from this account were made to meet the costs of doing business (including return to capital investors) whenever the regular income of the firm was insufficient. When the reserve fund fell below $1 million, the company was authorized to increase the price of gas. The firm was required to decrease the price of gas when the amount credited to the account decreased beyond the statutory limit.26

The reserve fund was unique to the Toronto service-at-cost plan. Since cost adjustments were tied to changes in the reserve fund and not specific items, the plan avoided rate base valuation problems, the historic nemesis of electric utility regulation.

In 1910, a service-at-cost franchise was adopted in Cleveland, Ohio. The plan was applied to the street railway industry since it afforded a basis of periodic, objective revisions of the fares charged. The use of service at cost expanded to other cities during World War I. About two dozen of these franchises were adopted between 1917 and 1922 to cope with rapidly rising production costs. The franchises fixed an initial property valuation and prescribed the introduction of later valuations as plant changes occurred. The rate of return was specified along with allowable operating expenses. Moreover, con-
tions for depreciation as fixed by the franchise; and a return on the value of the investment.

10 percent in the cost of debt capital. As part of this arrangement, a city equity account could be applied to the cost of the property if the city decided to purchase the utility at any time in the future. Thus, the plan was to act as "sort of a partnership arrangement between the city and the firm — with the aim of assuring complete control over day-to-day operations." 36

The Milwaukee Plan had a number of strong points that would have been critical factors in its application. The flexibility in the rate of return enabled the methodology to adapt to changing capital market conditions, a flaw in several of the early sliding scales. However, by tying the return on equity to cost of debt, if the equity market changed and no new debt was issued for an extended period of time, equity return could get out of step with the market.

Of special interest is the stabilization reserve. In addition to helping to relieve regulatory dependence on the rate base, the reserve had a mitigating influence on undue short-term fluctuations in rates. Such fluctuations could lead to customer confusion and dissatisfaction. Often the consumer (especially the industrial consumer) bases decisions on energy costs, and a reasonable level of stability in these costs would aid decision making. The stabilization reserve would tend to smooth out such fluctuations similar to an arithmetic moving average.

The close regulatory supervision on the part of the city was not necessarily a strong feature of the plan. Advance approval of operating and construction expenditures is desirable, but there is no assurance that the city employed adequate or qualified staff to supervise the plan. Furthermore, there was always the danger of political favoritism or unnecessary duplication or interference with the management responsibilities of the firm.

The disposition of excess earnings appears to destroy any incentive toward greater managerial efficiency. In contrast to the sliding scale, all of the excess returns not only were lost to management, but also if built up would serve to mitigate or replace the existing arrangement — a double incentive not to be efficient. What management was guaranteed, in effect, was only the prescribed rate of return — a simple cost-plus contract.
The cross-subsidy benefit in providing services that could not support themselves (for example, trash collection) is a discredit to the plan. This provision appears to be deceptive to the consumer, although it may be more palatable. Its use could lead to a great deal of internal cross-subsidization, for example, higher electric rates to users who consume a disproportionate amount of electricity but less than their share of the other services.

**The New Jersey Plan of 1944**

In 1944, a service-at-cost plan that did go into effect was negotiated between the New Jersey Public Service Commission and the New Jersey Power and Light Company. The plan was very similar to Glaeser’s Milwaukee proposal, in that it provided for a flexible base rate of return coupled to the cost of capital with a stabilization reserve.\(^4\) In addition, the reasonableness of expenses, depreciation, rate of return, and capital expenditures were to be determined and appraised on an annual basis.\(^4\)

The plan started with a basic property valuation of $16,750,000, including the original cost of the plant plus acquisitions. An allowance was made for working capital based on average book cost of fuel, supplies, and materials on hand, one-ninth of operating expenses (excluding taxes and depreciation), less the average of the two lowest month-end balances in the tax accrual and tax-reserve accounts. Changes in the valuation were allowed in the traditional manner as conditions changed.\(^4\)

The base rate of return was measured by three components: the actual cost of debt capital, the actual cost of preferred stock capital, and the earnings rates on the common stocks of comparable companies.\(^4\) The first two components, based on contractual rates, were readily determined. The return on equity was calculated based on an involved formula using several averages and adjustments, complicated by the fact that the firm’s stock was not actively traded on the market. Consequently, ten publicly traded utility stocks were chosen as a “barometer group,” with the equity return under the plan tied to the yearly average of the equity return of the barometer group. As a precaution, the equity return was limited to not less than 6.5 percent and to not more than 9 percent.\(^4\)

Each of the three components — common stock, preferred stock, and debt — was weighted according to the book capitalization of bonds, preferred stock, and common stock plus retained earnings.
preferred stock. The only aspect not subject to the AAC was common equity. Since the common stock was privately held, evidently the holders were not satisfied with existing market conditions for utility stocks as experienced by the barometer group. Readily accepting a post-World War II boom in the market, the stockholders balked when market conditions suffered during the Korean conflict. Such short-sightedness destroyed the plan and, along with it, its inherent benefits.

Furthermore, since the company's costs were subject to the AAC and the barometer group's were not, it would appear that as a response to the certainty in cost recovery, New Jersey Power and Light Company common stock was less risky than the barometer group's. Since lower risk translates as lower capital cost, the company enjoyed excess returns compared to the barometer group and lost the plan due to insufficient earnings but to excess greed.

Evaluation

The service-at-cost concept comes closer than any other form of ratemaking to conforming to the regulatory constraint outlined earlier. In addition, since all costs of doing business are recovered with little or no regulatory lag, uncertainty as to cost recovery is reduced. However, since costs can automatically be flowed through to the consumer, management may not be induced to operate in the most efficient manner. The traditional incentive to regulatory lag is gone, and no positive cash incentives are provided as in the sliding-scale plan.

Glaeser suggested prior and continuous regulatory approval of expenditures and continuous audit as a solution to this problem, but there was no guarantee that those responsible for supervising the plan were qualified or adequately trained and staffed to do so. The New Jersey Plan, by allowing a range in its stabilization reserve, overcame the problem in a more positive manner. There was a built-in incentive to try and keep the stabilization reserve at the maximum allowed. This is a possible solution to the cost control problem.

Finally, adjustments to preserve the preselected rate of return are made to the energy charge only and thus are added on as an across-the-board per unit charge. A major drawback to this procedure is that a change in plant capacity or customer requirements over time could alter the capital cost allocation (demand charge) to the various customer classes. Therefore, in the application of service at cost, periodic attention must be given to rate structure and demand charges to allocate capital costs properly and assure that rates do not get out of step with actual conditions.

Operating Cost Adjustments

Operating cost adjustments allow electric service rates to vary automatically but only to mitigate the effect of one (in rare cases, more than one) preselected, uncontrollable operating cost item. The first cases in which such provisions were considered by state regulatory agencies were decided in 1917.52 First taking form in the now common fuel clause, it was adopted by electric firms (with regulatory approval) to adjust rates as coal cost varied from a normal base cost. Historically, the fuel clause has been applied only to industrial electric service rates, with very few applications to residential service until recent years.

The basic concept of fuel cost adjustment may give the illusion of a straightforward methodology. Yet a simple one dollar increase in cost does not translate into an equal increase in revenue. The methodology has become more complex, with several issues yet to be resolved. Therefore, the basic definition has been expanded here in preparation for a detailed discussion of current issues.

Early Development to 1920

Although the historical records are often sketchy, current literature as well as Public Utility Reports indicate that the Alton Gas and Electric Company of Illinois, the Rockingham County Light and Power Company of New Hampshire, and the Bridgeton Electric Company of New Jersey were the first firms authorized by regulatory authority to apply an operating cost adjustment in the form of a fuel clause during World War I and briefly thereafter.

Fuel was a prime candidate for automatic adjustment since coal prices at the time became abnormally volatile. The main reason given for price variations was the manpower shortage in coal mines. Lack of labor to mine coal led to an artificially restricted supply. Compounding this problem was the severe shortage of rail service due to the demands for transporting war material from the midwestern industrial states to the East Coast.92 The rail problem reached historical development, which is often sketchy, current literature as well as Public Utility Reports indicate that the Alton Gas and Electric Company of Illinois, the Rockingham County Light and Power Company of New Hampshire, and the Bridgeton Electric Company of New Jersey were the first firms authorized by regulatory authority to apply an operating cost adjustment in the form of a fuel clause during World War I and briefly thereafter.

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such an acute level that the entire industry was nationalized and put under military control from 1917 to 1920.54

The commission order authorized the fuel adjustment clause (FAC) for Rockingham County Light and Power Company on 20 June 1917, stating simply: "On account of an abnormally high price of coal, a rate for electric current varying with the price of coal from which it is produced is reasonable."58 The Alton order on 29 June 1917 further demonstrated the utilities' plight and granted a mechanism for relief:

One-half the operating costs of the heat plant is a charge for coal, and coal at the present time is rapidly climbing in cost.

What the future price of coal is to be during the time wherein a schedule of rates is reasonably expected to prevail is largely a matter of considerable conjecture. . . . The most equitable solution here in would seem to be the establishing of a basic rate for heat service determined upon the 1915-16 coal prices, with provision made for a variable rate differential (both up and down) predicated upon the future average cost of coal to the petitioner.56

Due to the manpower and rail shortage discussed above, the usable supply of coal soon became inadequate.57 As a result, the use of the fuel adjustment clause proliferated quickly in response to the increasing prices required for the coal markets to clear. By 1918, regulatory commissions in Maryland, Massachusetts, Missouri, Vermont, Connecticut, and Rhode Island had approved FACs in electric utility rate schedules.58 By 1921, both California and Indiana had extended fuel adjustment to domestic rate schedules.59

The following quotations from utility executives, at the time, demonstrate why the idea spread so rapidly:

In (JUT opinion, unless central stations get some relief by being allowed to increase their rates, they will be in very serious financial condition before the end of 1918. We are arranging to ask for an increase in all of our rates, based on the increased cost of production. The outlook for the winter is serious.

After the severe strain has passed coal prices will necessarily drop, but under the present tension it will be necessary for many plants to increase their rates, either temporarily or permanently, in order to take care of the increased cost.59

Historical Development

Several firms were concerned with the capital attraction problem that was threatened by lack of immediate cost recovery: "In the indefinite future, operating expenses will be much higher, and rates must be increased proportionately if good service is to be given the public and the necessary and proper rate of return on investment obtained, so that the necessary new capital can be secured. The price of coal affects our conditions so seriously that radical changes in all rates will be necessary if the company is to live and expand. No new money can be obtained for extensions or improvements at this time."59

As a response to uncertain cost recovery, the capital markets were behaving in the proper manner. Although doubtful that absolutely no money was available, due to the risk involved in uncertain cost recovery, an abnormally high discount rate was being placed on future earnings and the cost of money had risen proportionately. This reaction of the capital markets points out clearly the problem faced by today's utilities during similar periods of uncertain cost recovery.

Even though the FAC provided a mechanism for immediate cost recovery, there was little agreement as to the proper methodology for calculating fuel cost. Subject to early dispute was the method of costing coal, either on a Btu content basis or cost per pound. Also, handling and transportation costs, adjustments for hydroelectric generation, and the use of a "neutral zone" (a range in the tariff where the FAC would not apply, to prevent small variations in the rates) were subject to debate. These issues were never satisfactorily resolved and have plagued regulators and utilities alike to the present day.

Not all regulatory commissions in existence at the time were willing to go along with the fuel clause adjustment. The reasons for their refusals were best described by J. H. Foy in a survey of early fuel clause use:

The reason most commonly advanced was that the use of such a provision would be an unlawful delegation to the utility of the commission's authority to regulate rates. Some commissions thought the technique to be incompatible "with the spirit and purpose" of regulatory law; others, that authority to increase rates could not be made contingent upon a future event. Another reason sometimes advanced was that fluctuating utility rates would confuse the consumer, who was considered to have a right to know his utility rate with certainty in advance. Adjustment clauses were denied where competition between suppliers of fuel to a utility tended to
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keep fuel prices in line. And it was said that the allowance of automatic adjustment for increases in fuel prices would reduce management's incentive to buy fuel as cheaply as possible. There was among some commissions the feeling that utility rates should not be subject to automatic adjustment upon consideration of only a single cost factor, such as the cost of fuel, since other costs might have decreased. On the other hand, one commission denied an automatic adjustment which would have been based on all operating costs.

1920 to 1930

In spite of administrative caution, the fuel adjustment idea spread. By the 1920s it was a recognized and widely accepted method of utility ratemaking. With the end of the war and its inflationary pressures, normalcy brought with it pressure to eliminate the FAC in some states:

"Coal clauses"... adopted by utilities to meet the unusual conditions confronting them during the unsettled times incident to the war, should be superseded by more definite rates calculated to produce the required revenue.

The Commission eliminated from the filed tariff of an electrical utility a coal clause which would automatically increase or decrease with fluctuations in the price of coal, in view of the superior jurisdiction and duty of the Commission to adjut utility rates at all times.

Considerable time at the hearings was devoted to the coal surcharge. It was suggested that it be eliminated entirely.

The post-World War I period saw not only a return to normalcy in coal prices but also an upsurge in the demand for electric service. Cost stabilization along with increased demand brought lower unit costs to the utilities. The commissions were foolish in removing the fuel adjustment clause during that period as the clauses could have passed cost savings forward to the consumer. In the same vein, the utilities clearly found it in their best interest to eliminate the fuel clauses and perhaps encouraged the commissions to do so.

1930 to 1940

Public Utility Reports revealed only two cases concerning automatic adjustments from 1930 to 1940. In 1933, a tax adjustment clause was proposed for the first time in response to the proliferation of new and increased taxes during the New Deal. The attempt was to shift this burden to the consumer, but the regulatory commission disapproved: "A water utility's rate schedule which contained a so-called 'tax clause' providing for automatic rate additions or reductions for all classes of service in accordance with fluctuation in the public taxes imposed upon the utility was held to be without justification where the amount of the tax burden in comparison with other costs of furnishing utility service was not believed to be increased to such an extent as to justify the imposition of a device for automatically shifting the burden to the consumer."

Concern for the consumer was the primary factor in a case in 1935, before the New York Public Service Commission. The order resulting from this proceeding stated that the fuel clause should not apply to residential rates, although such application had been accepted to a limited extent by other jurisdictions since the early 1920s. "[The fuel clause] will make an additional entry on nearly 20,000,000 residential customers' bills per year of amounts so extremely small that it is not worth the added cost. Further, most small consumers would find it difficult to understand the operation and justification for the clause.... The proposed clause should not be made applicable to residential rates."

1940 to 1950

World War II and the postwar period, with its swift inflationary spiral, brought considerable activity in automatic adjustment of utility rates, since public utilities were exempt from the Emergency Price Control Act. Most prevalent was the purchased gas adjustment clause. The rapid growth in the use of natural gas after the war accelerated the acceptance of the adjustment clause, because of the volatility of wholesale natural gas prices.

Of interest during this period was an attempt by the Connecticut Public Service Commission to define specifically and provide guidelines for the utilities in designing a uniform fuel adjustment clause applicable to each electric utility under its jurisdiction. This issue is of significance because, recently, a number of states have taken up the uniform fuel clause issue. In the following excerpt from the order, several aspects of the FAC were addressed in an attempt to clarify unresolved issues. The price of coal, whether to include or exclude transport and handling costs, as well as other components of the calculations and methodologies (for example, the neutral zone,
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generator efficiency, and the definition of fuel cost) were previously not defined in sufficient detail. As will be discussed later, these issues have come up in uniformity hearings recently in Ohio, Kansas, Kentucky, Illinois, Maryland, as well as in a number of other states.

The legality of the AAC came up in a case in 1947. The legal issue, resolved to some extent by the mid-1960s, remains open in many instances: "The law imposes a duty upon the Commission to require fixed and definite rates in a gas rate schedule and the Commission has no legal authority to delegate its functions in this regard by permitting a fuel adjustment clause." 71

The controversy surrounding FAC use at this time is demonstrated by the methodology for calculating the adjustment for hydrogeneration. Hydrogeneration enjoys a relatively minimal amount of operating cost compared to fossil fuel generation. It would be logical to assume that the variance in hydro-related cost items would be practically nonexistent. Consequently, an attempt was made to segregate hydrogenerated kilowatt hours and assign them to customers who were not subject to the FAC. In this fashion, a greater portion of the increase in fossil fuel cost could be recovered. Not only is the method impossible electrically, but also it is a very deceptive tactic on the part of the utility: "The Commission in passing upon a proposed formula for calculating fuel adjustment rates ... rejected as invalid the assumption that hydrogenerated power can be considered as dedicated exclusively to the use of customers who are not subject to the company's fuel clause." 72

Perhaps the most controversial issue during the 1940s was the incorporation of taxes into the automatic adjustment mechanism. The tax issue met with both opposition and success:

Tariff provisions for variations related to cost of purchased power and increases in taxes are not the only or best means by which a public utility may be protected against increases in operating and tax costs which result from extraordinary or emergency conditions (emphasis added). 74

An electric utility was permitted to include, in its schedule for rates ... a provision for an adjustment in cases of tax increases or the imposition of new taxes. 75

The concern for relief from the imposition of additional taxes was prevalent among utility officials since the uncertainty of imposition and recovery of the new taxes was reflected in the capital markets. 76

Again the capital markets were playing their proper role. Taxes are, of course, a part of the cost of service. As stated above, the uncertainty in the nation's tax policies at the time was reflected in the capital markets. The regulated sector suffered since the increase in taxes could not be readily passed on to the consumer, but would come out of the stockholders' earnings until the regulatory process took place. The tax adjustment clause was an attempt to eliminate this uncertainty, thereby lowering risk and restoring investor confidence.

A new type of AAC appeared in 1948. The clause allowed rates to vary to maintain a relatively stable competitive relationship between electric utility rates and the cost of customer generation of power. 77 Similarly, some natural gas utilities were allowed to publish schedules providing that gas rates would be adjusted in accordance with fluctuations in the price of oil. However, these types of clauses did not meet with widespread approval. The use of adjustment clauses for competitive purposes by any type of utility was limited to Hawaii, Wisconsin, and California. 78

1950 to 1960

During the 1950s, the vast majority of electric utilities had automatic adjustments in effect. Fuel clauses were included in retail electric rates in forty-four states; tax adjustment clauses had been adopted in thirty-four. In seven states where electric utilities were subject to state regulation, and in two where such regulation did not
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exist, adjustment clauses appeared based on changes in costs other than fuel and taxes (for example, wages, cost of debt). Idaho, Montana, Oregon, and Washington did not have fuel clauses — all areas of practically exclusive hydrogeneration.76

During the early 1950s, with the inflation caused by the Korean conflict, the fuel clause was again extended in a few cases to residential rates.80 Although most commissions rejected this extension for reasons cited previously, a few accepted it:

An electric company's proposed fuel adjustment clause was approved in the case of industrial users but denied in the case of commercial or residential users.81 The fuel adjustment clause of an electric company's rate schedule should be applied against residential and all commercial classes of customers, since cost of fuel is one of the necessary out-of-pocket costs borne by the company which should be recouped from its customers.82

The FAC was authorized in most jurisdictions, but it was applied very little during the mid- and latter 1950s. Although average cost of fuel had increased about 10 percent during the period, generating efficiency had also increased about 10 percent, providing an offset.83 This efficiency gain did not go unnoticed by utility regulators:

An electric utility's fuel adjustment clause should be so worded that customers will reimburse it for increased fuel costs based on actual system efficiency rather than on the basis of fixed factors.84 A fuel adjustment clause which contemplates nothing more than the changing market price of fuel is not realistic and does not give the customer the full benefit of improved operating techniques and increased efficiency.85

The adjustment for efficiency was clearly in the public interest. As stated earlier, a disadvantage of automatic adjustment comes about because only one cost item is singled out. If other cost items are falling, the use of the automatic adjustment clause, in practice, could cause an overcollection of revenue requirements. Regulatory agencies became concerned about this problem when significant gains in productivity were experienced during the 1950s.

Table 3.1 shows the amount of increase in fuel expense for the years 1945 to 1959.86 As shown, the average price per kilowatt hour sold actually fell during the period as a result of productivity increases.

### Table 3.1: Fuel Expense for Class A and B Electric Utilities 1945–1959

<table>
<thead>
<tr>
<th>Year</th>
<th>Electric operating revenue (thousands)</th>
<th>Fuel expense (thousands)</th>
<th>Percent of revenue</th>
<th>Average cents per kwh (residential)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1945</td>
<td>83,171,457</td>
<td>3,374,930</td>
<td>11.8</td>
<td>3.47</td>
</tr>
<tr>
<td>1946</td>
<td>8,382,566</td>
<td>418,432</td>
<td>12.7</td>
<td>3.29</td>
</tr>
<tr>
<td>1947</td>
<td>3,097,868</td>
<td>599,734</td>
<td>19.9</td>
<td>3.14</td>
</tr>
<tr>
<td>1948</td>
<td>4,187,285</td>
<td>772,657</td>
<td>18.5</td>
<td>3.06</td>
</tr>
<tr>
<td>1949</td>
<td>4,581,849</td>
<td>689,765</td>
<td>15.3</td>
<td>3.01</td>
</tr>
<tr>
<td>1950</td>
<td>4,783,860</td>
<td>757,483</td>
<td>15.5</td>
<td>2.95</td>
</tr>
<tr>
<td>1951</td>
<td>5,238,259</td>
<td>856,269</td>
<td>16.3</td>
<td>2.89</td>
</tr>
<tr>
<td>1952</td>
<td>5,690,417</td>
<td>912,451</td>
<td>16.1</td>
<td>2.85</td>
</tr>
<tr>
<td>1953</td>
<td>6,167,257</td>
<td>1,093,975</td>
<td>16.3</td>
<td>2.84</td>
</tr>
<tr>
<td>1954</td>
<td>6,519,143</td>
<td>977,991</td>
<td>14.9</td>
<td>2.80</td>
</tr>
<tr>
<td>1955</td>
<td>7,199,046</td>
<td>1,093,000</td>
<td>15.1</td>
<td>2.76</td>
</tr>
<tr>
<td>1956</td>
<td>7,780,147</td>
<td>1,238,956</td>
<td>15.7</td>
<td>2.71</td>
</tr>
<tr>
<td>1957</td>
<td>8,308,575</td>
<td>1,372,269</td>
<td>16.5</td>
<td>2.08</td>
</tr>
<tr>
<td>1958</td>
<td>8,708,577</td>
<td>1,329,046</td>
<td>15.3</td>
<td>2.66</td>
</tr>
<tr>
<td>1959</td>
<td>9,497,664</td>
<td>1,447,105</td>
<td>15.2</td>
<td>2.54</td>
</tr>
</tbody>
</table>


Adjustments for efficiency, although theoretically sound, were very difficult to put into practice. Furthermore, other issues such as offsets for hydrogenation, calculation of line losses, neutral zones, customer classes to be covered, handling and transportation costs, and purchased power were subject to wide differences of opinion as to how they should be incorporated. One writer observed: "One can hardly undertake a review of the positions of various state utility commissions without soon coming to the conclusion that he is stumbling around in a morass of utter confusion and contradiction. It is difficult to understand how commissions can come out at so many varying ends unless each permits the applying utility to write its own rates according to its own notion. Few commissions seem to read or be guided by the decisions of others to the end that trends of legal harmony are difficult if not impossible to find."87

Tax clauses also flourished during the 1950s. Thirty-four states allowed some form of automatic tax adjustment, with twenty-five applying the clause to all customer classes. The forms of these clauses, though individually varied, applied to gross revenue taxes, property taxes, and franchise taxes. No adjustments for income taxes were reported at the time.88 Although Public Utility Reports contains very few tax adjustment clauses, in some instances the regulatory
Automatic Adjustment Clauses

commission allowed publication of tax clauses without objection, relying on their general supervisory powers. There was a substantial increase in purchased gas adjustment clauses, due to steadily increasing prices. Finally, there was considerable debate, as indicated in several Public Utility Reports, concerning the legality of the automatic adjustment clause. The debate continued through the 1960s and remains to some extent today.

1960 to 1970

The electric utility industry was relatively stable in the 1960s. Although productivity gains began to slack off in the later part of the decade, external financing was not as prevalent as in the 1950s or the present day; and fuel costs were relatively stable throughout the period, thus reducing the pressure for rate relief. In fact, rates generally declined during the mid-1960s as did the use of automatic adjustment clauses. Public Utility Reports shows very little activity, with the exception of natural gas adjustments. As noted by the Connecticut commission: "The price of fuel is relatively stable. We note that fuel does not constitute as large a proportion of the company's overall expenses as it did in 1944."

In a similar case in Florida, the commission expressed the view that fuel adjustment clauses served "a most worthwhile purpose," but that fuel cost had been considerably stabilized, making the need for the adjustment clause less compelling than in previous inflationary periods.

Although there was no mention of automatic adjustment clauses in the 1935 Federal Power Act, the Federal Power Commission never rejected the fuel clause per se in an electric rate schedule. On 26 September 1963, the commission issued Order No. 271, effective 1 November 1963, promulgating what is now Section 35.14 of the regulations under the Federal Power Act. The order specifically provided for an FAC stated in terms of cents per million Btu limited to changes in fuel cost items included in Account 151 (Uniform System of Accounts for Public Utilities and Licensees). In addition, it provided for the exclusion of hydrogenerated power, but required utilities to file supporting data each time a change was made in the FAC. This provision proved cumbersome in application and necessitated consideration of FAC changes on a case-by-case basis with considerable lag, defeating one of the major purposes of automatic adjustment. This order was superseded in 1974.

Legal resolution of the AAC at the federal level in the above order had its counterpart at the state level. During the 1960s, the question of the legality of automatic adjustment clauses was considered by most state regulatory commissions and by the courts. The legal issues centered around constitutionality, notice and hearing requirements, abdication of regulatory authority, and the need for prior regulatory approval before rate changes could be made.

The Supreme Court of Ohio made short shrift of the constitutionality objection in City of Akron v. Public Utilities Commission. The constitutional issue was raised as to the adoption of a gas adjustment clause:

The "gas escalation clause" which is approved in connection with the order dated November 20, 1964, is attacked by the cities upon two grounds. It is claimed that the inclusion of any gas escalation clause in the commission's order is an unconstitutional delegation by the commission of its power to set rates. It is claimed that if such escalation clauses are not unlawful for this reason then this particular escalation clause is so vague that the commission's action in approving its use was "arbitrary and capricious."

The record discloses that the claim of vagueness is without factual basis. Permitting an escalation clause has the effect of eliminating one of the variables which would otherwise distort the dollar amount of earnings which the commission's order contemplates will be reasonable and which will result from the application of the approved rate of return (6.25%).

In regard to notice and hearing requirements, the courts have held that regulatory commissions can allow fuel clauses under their general statutory power to set just and reasonable rates. In City of Norfolk v. Virginia Electric Power Company, the court commented that the fuel adjustment clause was "simply an addition of a mathematical formula to the filed schedules of the company under which the rates and charges fluctuate as the wholesale cost of gas to the company fluctuates." The court also stated: "It is clear that notice is not required on each occasion there is a change in the ratepayer's bills, but that notice is required for every change in the filed schedules which are the underlying bases for the computation of those bills."
The notice and hearing issue has been revived recently. An increasing number of states now require notice and a hearing (although brief) before the AAC can go into effect.

The question of abdication or delegation of commission authority arose in the Virginia Electric and Power Company case cited previously. The commission stated:

We lose none of our power by approving the Escalator Clause. We can, by procedure established by law, investigate the rates charged by the company at any time and require whatever changes in rates may be appropriate.

The objection is raised that the commission should not permit rate changes without a complete review of the company's operations. Utilities are under constant supervision of the commission. The rate of return of all utilities is the object of study and investigation by our accounting and engineering departments continuously. We cannot agree, therefore, that there is any unconstitutional delegation of power in the proposed escalator clause.

Similarly, the requirement of prior approval was disposed of by the Illinois Supreme Court in City of Chicago v. Illinois Commerce Commission. The court held that the use of automatic adjustment clauses did not result in an unauthorized change in rates:

The city of Chicago contends that the authorization of the automatic adjustment clause contravenes section 36 [Illinois Public Utility Act] and permits changes in rates without the filing of rate schedules and constitutes an abuse of the exercise of the commission's discretion. We cannot agree.

Under the common, as well as statutory definition, it is clear that the statutory authority to approve rate schedules embraces more than the authority to approve rates fixed in terms of dollars and cents. The present automatic adjustment clause is a set formula by which the price of natural gas to the ultimate consumer is fixed by inserting in the formula the wholesale price of natural gas as established by the FPC. The Public Utilities Act, taken as a whole, contemplates that a rate schedule may contain provisions which will affect the dollar-and-cents cost of the product sold.

Although the AAC has not been found to be illegal, a number of jurisdictions have recently passed or proposed legislation to modify its application (specifically the notice and hearing requirement), or even in some cases forbid their application altogether. This development will be discussed in the next chapter.
Automatic Adjustment Clauses

ground) or its customers (without proper maintenance the facilities will require earlier replacement and result in lower quality service in the interim).

On the other hand, opponents to the FAC claimed it discouraged hard bargaining for fuel. It is difficult to analyze the validity of this argument on a historical basis. Again, there are no cash incentives or penalties to guide management action. This may have encouraged sellers to hold out for higher prices.

Price discrimination is another drawback of the FAC. Historically, the FAC has not been applied to all customer classes. This may be discriminatory since it could shift a greater portion of costs to a particular group of customers, benefiting one group over another. Of even greater consequence is the problem of peak as opposed to off-peak service.

Even when the FAC is applied to all customer groups, the off-peak user is penalized, because during peak periods generally higher fuel cost plants are in operation (for example, a diesel fired peaking plant). Yet, there is no adjustment mechanism in the FAC methodology to charge the peak user with a greater portion of the cost of fuel. The resulting cross-subsidization discriminates against the off-peak user.

These issues are coming into sharper focus in today's regulatory climate and will be taken up in more detail in the next two chapters.

Current Status of Service-at-Cost Adjustment Clauses

The objective of this chapter is to examine the current status of the service-at-cost adjustment clause, specifically recent applications, methodologies, and legal status. Where applicable, recommendations are made as an integral part of the analysis.

The service-at-cost concept, in contrast to the sliding scale, is still very much alive. In December 1973, the New Jersey Public Utilities Commission approved a service-at-cost adjustment clause for the New Jersey Bell Telephone Company. Following New Jersey's lead, on 29 March 1974, Illinois Bell Telephone Company filed a proposal for a "cost and efficiency" service-at-cost adjustment with the Illinois Commerce Commission. Although the Illinois Bell proposal was disapproved in early 1975, it represented a useful hybrid of the benefits of the sliding scale and service at cost. Applied to electric power, a service-at-cost plan was approved for Public Service Company of New Mexico in April 1975.

The New Jersey Plan of 1973

In its order of 29 December 1972, as part of a rate increase application of New Jersey Bell Telephone Company, the New Jersey Board of Public Utility Commissioners proposed the adoption of a service-at-cost automatic adjustment clause: "In recognition of economic conditions and the resultant financial status into which utilities have been forced, the Board proposes to initiate a comprehensive adjustment clause. This clause will be designed to make rate regulation more responsive to the financial needs of a utility,
which is required to provide safe, adequate, and proper levels of customer service."^6

On 15 February 1973, the commission initiated hearings on the plan and in December issued its decision and order of approval. Under the order, automatic adjustments in rates were allowed annually on the basis of any changes in all major components of costs: wages and salaries; taxes, excluding income taxes; all other expenses; and depreciation. 6

With regard to wages and salaries, the board allowed, subject to change, an adjustment tied to the federal guidelines of 3.5 percent, then in effect, plus an additional 0.7 percent for fringe benefits. From this figure, 4.0 percent — the average rate of increase in output per man-hour in the telecommunications industry, based on U.S. Labor Department figures — was deducted. This implies that the total wage bill, assuming constant output, could increase at no more than 2.2 percent each year. This requirement provided management with a great deal of incentive for hard bargaining during labor contract negotiations, but could have forced suboptimal substitution of capital for labor. The telecommunications industry has been criticized for its alleged capital bias in the past. The wages and salaries portion of the plan could have aggravated that bias even further since all capital inputs were automatically passed through as part of the AAC, whereas the amount of passthrough on labor input was limited.

The tax category excluded federal income taxes, but included property taxes, gross revenues taxes, and Social Security taxes (generally considered a fringe benefit, but the board chose to include the cost here). The clause automatically allowed adjustment for changes in effective tax rates applicable to the current rates in each of these categories. However, at times the state or federal government may adjust income tax rates for reasons other than collection of revenues (namely, the investment tax credit designed to stimulate investment). Therefore, the plan did not include a provision for automatic adjustment for income taxes so as not to mitigate state or federal tax policies.

The other expense category was tied to "actual expenses of the increase in the Industrial Wholesale Price Index . . . or the actual increase in other expenses, whichever is less." By coupling the other expense category to the industrial wholesale price index, the firm is provided with the stimulus of a simulated external market. It receives a penalty in the form of underrecovery if its cost increases (as a percentage) exceed those of the industrial wholesale price index. However, the firm cannot enjoy the benefit if it outperforms the price index, since the other expense category is tied to actual expenses if the firm is relatively more efficient than allowed by the index.

The formula permitted a depreciation adjustment limit found by an analysis of the relationship of the depreciation expense to operating revenues: "An analysis of plant investment, depreciation charges and revenues over the period since 1958 indicates that depreciation charges consistently represent approximately 12 percent of revenues. In the test year (1972) the relationship is 12.5 percent. To the extent that additional facilities are necessary and that the related depreciation charges do not cause the 12.2 percent ceiling to be violated, the board will allow adjustment to depreciation expense." In addition, the board stated, "depreciation will not be based on test-year expenses but the relationship of normal depreciation charges to the level of revenues at the time of review. This more generous adjustment for depreciation reflects the company's commitment to expansion and modernization of facilities and the board's desire for continued service improvement."^10

Thus, the formula placed a lid on the amount of depreciation expense that the firm could generate but did not discourage innovation and development by unduly restricting capital recovery. At the same time, overexpansion was not encouraged since there was a limit to the amount of the expansion that could be recovered in any given year. Had the plan continued in existence for a number of years, it would have been interesting to examine the effect of this particular aspect of the plan on the firm's actual construction in relation to other Bell system companies.

The board denied a request for an interest expense adjustment, but built interest expense into an overall rate of return limit. Furthermore, any change in the return limit could be made only in a formal rate case. This feature is to the plan's credit, since it avoided the rate of return problems of the New Jersey Plan of 1944. However, "even though a clause [as described above] may calculate an indicated revenue increase, there will be no revenue increase if the company is at the allowed rate of return without the aid of the adjustment clause."^11

The New Jersey Bell Plan was an excellent regulatory tool. It continually adjusted service rates to match cost but there were a
number of incentives built in to stimulate management and prevent abuses. The limitations on depreciation and the limitations on labor and other expenses served to provide an external "market" for which the firm could compete.

The plan was challenged by the New Jersey state attorney in 1975, but the court ruled in favor of the board, noting however that any rate increases authorized under the plan must be subject to a hearing. This provision substantially diluted the intent of the plan by removing the automatic feature.

The New Jersey Supreme Court stated:

In a rate proceeding utility expenses to be allowable must be justified. Good company management is required; honest stewardship is demanded; diligence is expected; careful, even hard bargaining in the marketplace and at the negotiation table is prerequisite. And so it must be with regard to expenses recouped by "flow-through" to consumers by dint of a comprehensive adjustment clause. Tested in the scrutiny of the final rate determination and only in that way (despite the impressive monitoring devices built into the instant clause) can such expenses be validated and become demonstrably honest components in the ascertainment of "just and reasonable" rates. Lacking that validation, certainty and justification, the rates would have been unjustly charged and to the extent of that injustice must be refunded to the customers. That protection being provided in unmistakable terms, however, we would see no reason for this court to disagree with the PUC adoption and the continued operation of the comprehensive adjustment clause, pending, as we say scrutiny of such expenses in final hearing.12

Although the court ruled in favor of the New Jersey board, this ruling sounded the death knell to the New Jersey Bell comprehensive adjustment plan. In its order dated 15 September 1975, the Board of Public Utility Commissioners abandoned the plan and returned to the traditional ratemaking process. It cited two main reasons for its action, the above supreme court ruling and the inability of the utility to meet the wage guidelines as outlined in the plan. With regard to the elimination of the automatic feature, the board stated in its order, "our understanding is that the prior Board initiated the (comprehensive adjustment clause) experiment with the intention of not conducting hearings on expenses recovered pursuant to (comprehensive adjustment). The requirement of a hearing diminishes the value of a (comprehensive adjustment clause). . . . This decision [the supreme court decision outlined above] concludes the instant rate case and, therefore, there is no need to continue the (comprehensive adjustment clause)."

In regard to the wage problem, the board stated:

We find that the record does not support the conclusion that petitioner is capable of achieving productivity gains of 4 percent. Such figure was based on national averages over a long period of time during relatively stable economic conditions and does not appear feasible in today's volatile economy . . . . Furthermore, productivity is desirable and should be used as an incentive for increased efficiency rather than as a penalty based on questionable assumptions . . . . For the foreseeable future productivity gains may wage a losing battle against attrition in earnings. Therefore, based on the record herein the productivity offset is highly speculative and, in a period of double digit inflation, of doubtful validity.13

Thus ended the New Jersey Bell Plan. As with its predecessors, its demise came during a period of rapid inflation and court concern over the automatic provision, the heart and soul of the automatic adjustment clause.

The Illinois Bell Proposal

The following service-at-cost model was proposed to the Illinois Commerce Commission by the Illinois Bell Telephone Company in March 1974:

\[
\text{CEA} = (ax + by) \text{or} Z, \quad (4.1)
\]

where: \( \text{CEA} = \) cost and efficiency adjustment in dollars;
\( x = \) aggregate dollar value of the percentage change in unit cost (plus or minus), exclusive of net income (return to equity) before income taxes;
\( y = \) aggregate dollar cost saving (plus or minus) associated with changes in efficiency;
\( z = \) change in aggregate revenue (plus or minus) required to meet the allowed ceiling rate of return; and
$a, b = \text{coefficients as specified in the tariff to permit full recovery of unit cost changes if the change in total productivity equals or exceeds the recent trend rate for the company.}$

The first term of the formula, $aX$, pertains to changes in unit costs, excluding equity costs, and therefore relates directly to the degree of cost increases or decreases and inversely to the change in productivity. The second term, $bY$, is designed to reward the company in a manner similar to the sliding-scale concept. Under the plan, if unit costs decline, the first term $(aX)$ becomes negative. If the historical level of productivity (measured in terms of increased output per unit of input) remains the same, the second term $(bY)$ is zero. However, if productivity declines, management is penalized since $bY$ becomes negative, and the CEA adjustment reduces the cost of service. But if productivity increases, management is rewarded since $bY$ becomes positive, thereby increasing consumers’ bills. $^{15}$

Initially, the coefficients $a$ and $b$ were to be set at 0.5 and 1.5, respectively. Thus, only one-half of the increases in unit costs would be automatically recovered if the firm’s efficiency continued at its past level. The 1.5 weight $(b)$ was to provide the company with the other half of its unit cost increases, if the productivity increase was at least equal to the past trend rate. Given an $a$ coefficient of 0.5 and a trend rate of total productivity advance of about 2.5 percent per annum, the size of the $b$ coefficient was set based on an annual inflation rate of 6 to 8 percent. $^{16}$ In effect, $b$ in the formula adjusted the efficiency award for the effects of inflation, a key problem of the early sliding scales.

In the formula, $Z$ was to provide an overriding factor. Each month, $Z$, the increase or decrease in revenue required to earn the allowed rate of return on the rate base, was to be calculated to replace $(aX + bY)$ if $Z$ was smaller. Thus, the efficiency rewards would not become excessive.

Note the constraint that $Z$ built into the formula. The utility would be provided with the incentive to earn its rate of return, but it would not be allowed to gain excess profits. Similar to the New Jersey Bell Plan, the utility would have the constant stimulus and potential of receiving its allowed rate of return. Thus, the formula would work in a manner similar to formal ratemaking procedures but not suffer the long period of regulatory lag and the expense and burden of regulatory proceedings. In effect, the allowed rate of return was to be set as a target; something the firm could strive for but, in contrast to the traditional procedure, it could accomplish in a shorter time. However, the firm would not be under a cost-plus contract as in the earlier service-at-cost plans since the formula would force the firm to match or exceed past performance. If, and only if, efficiency improved to a point sufficiently above historic levels the firm would be allowed to recover 100 percent of its cost increase.

Thus, the cost-plus feature of the service-at-cost AAC was to be avoided along with its drawbacks. Furthermore, the plan did not provide for unlimited compensation, a problem with the early sliding scales.

To eliminate problems of seasonal and erratic movements, the rates of change in operating expenses and output were to be computed as quotients of the most recent 12-month moving total and the 12-month moving total ending with the preceding month. The other cost aggregates were 12-month moving totals, ending in the latest month. Because of data lags, the surcharge factor for the most recent month was to be based on variables (other than productivity) for the period ending two months earlier.

The productivity factor was calculated by methods developed by Illinois Bell consultant, Dr. John Kendrick. The primary methodology used was the now well-recognized total factor productivity index. Total factor productivity is the output per unit of input computed for each factor used in production. The ratios were deflated to 1967 dollars and thus provided a measure of technical efficiency over time. $^{17}$

In February 1975, the Illinois Commerce Commission rejected the plan primarily because it felt the plan was an abdication of the regulatory process. It may appear that the commission was shying away from automatic adjustment in contrast to the case described in the previous chapter (City of Chicago v. Illinois Commerce Commission). However, the commission’s basic reason for rejecting the plan was the feeling that those items allowed automatically to flow through were under management discretion and, therefore, inconsistent with the basic definition of automatic adjustment. As stated in the commission’s order:

At the present time the reasonableness of operating expenses can best be determined by the Commission in retrospect and after a
reasonable opportunity to examine individual items of expense on
an accumulated basis in comparison with other periods of time. The
Commission is of the opinion that at the present time and under
present economic conditions the determination of the just and rea­
sonable nature of operating expenses incurred by Bell is best ac­
complished by hearings concerning the propriety and reasonable­
ness of proposed rates . . . and not by an automatic revenue adjust­
ment clause such as proposed herein . . . . It is the obligation of this
Commission to pass judgment upon the just and reasonable nature of
operating expenses incurred by the Company and the obligation of
the Company to exercise proper judgment when incurring such
expenses. It is the control . . . (the Company has) over such expendi­
tures which distinguishes the CEAC formula from the automatic
rate adjustment clause approved by the Supreme Court of Illinois in
the case of the City of Chicago v. Illinois Commerce Commission.19

The commission also felt that economic conditions did not justify
a circumvention of the traditional process, that is, the Bell System
did not suffer from the same maladies of inflation that the electric
power industry was experiencing: "The evidence in this proceeding
demonstrates that under the present method of ratemaking, Bell's
charges are approximately the same as they would have been had the
CEAC formula been in operation during the past several years."20

The commission's response to this particular automatic adjust­
ment mechanism was primarily a reaction to abdication of its author­
ity and the relative control management would have over the au­
tomatic flow through of its operating expenses. As stated in the order:
"The operation of the proposed CEAC formula would allow a very
substantial portion of any increase in operating expense experienced
by Bell to be recaptured by flow through to its customers without
providing this Commission with an opportunity to fulfill its regu­
latory obligations by examination of such expenses in a retrospective
and comparative manner; in the operation of the Illinois plan the flow
through of the expenses was prospective in nature. It was this last
feature that caused the Illinois Commerce Commission to shy away
from this particular regulatory tool.

The New Mexico Plan

Recognizing that continually fluctuating costs offer at best a mov­
ing target in setting rates, the Public Service Commission of New
Mexico instituted a service-at-cost plan for use by Public Service
Company of New Mexico (PNM) in its Order No. 1196 dated 22 April
1975.21 The commission felt that with such a plan it would have more
time to investigate systematically and reflect upon "management
efficiency, prospective growth in demand as a justification for new
plant certification, service rate structuring as a method of more effi­
ciently allocating and conserving resources, minimum cost financing
programs and other matters which may result in cost savings, as well
as increased reliability and quality of service."22

Thus, the New Mexico Plan is more service at cost in nature than
either the New Jersey plan or the Illinois Bell proposal. It is also
more comprehensive in that it allowed any and all cost increases to
flow through and adjusted rates automatically when the rate of return
was above or below a specified range on either side of the
allowed rate of return. The range allowed was initially set between
13.5 and 14.5 percent.

The goal of the New Mexico Plan has been to follow cost of
service as closely as possible. However, in providing for automatic
adjustment in revenues, the cost of common equity is excluded.
Common equity cost is left to the formal regulatory process, a desira­
able feature discussed earlier. Furthermore, the plan is not coupled to
changes in a single cost item, allowing savings in cost factors to
mitigate increases elsewhere.

The New Mexico Public Service Commission chose to follow this
rather innovative rate experiment for several reasons, as stated in the
original order:

First, cost-of-service indexing does not guarantee investor "profits,"
Rather it affords the best assurance we can devise that PNM will be
able to pay its minimum costs of capital, which as we construe the constitutional requirements and our statutory mandate, we are obliged by law to do. Second, in historically demonstrated theory as well as by initial market indication, and reactions, cost-of-service indexing will not contribute to inflation; rather, it will have a moderating influence, at least, and it may well effect both a short and long-term reduction in the costs of capital for PNM. Third, PNM's incentives to resist cost increases and to effect economies are not reduced by the new method. This is the purpose of establishing a band or range of return. Fourth, in addition to preserving management efficiency incentives, the new method also enables the company to implement the efficiencies good management planning may devise. These planning goals are not attainable and they will not serve the public or consumer interests if frustrated by the energy utility's inability to attract and capture the necessary capital. Fifth, the new method promises to improve the efficiency and the input of this commission and its staff. Sixth, the new method of rate regulation passes on to the consumer only the net result as either an increase or a decrease in service rates. Unlike cost of fuel indexing it is not tied to only one cost of service. Seventh, the cost-of-service indexing formula implemented here encourages energy conservation. Eight, the cost-of-service indexing method of service rate regulation will be much more convenient to administer and modify than traditional methods, and it will enable the commission to respond much more readily to the current economy and to the requirements of the capital markets.25

The plan was modified in a subsequent proceeding on 29 December 1978 (Case No. 1419). In this order, the commission eliminated the quarterly adjustment by allowing only an annual one, tightened the procedures for monitoring and evaluation, and eliminated the 13.5-14.5 percent range. The return on equity was set at 13.5 percent. Except for these modifications the plan is still in effect.

Under contract with the U.S. Department of Energy, the National Regulatory Research Institute prepared an evaluation of the New Mexico cost-of-service index in May 1979. The report was critical of the plan and demonstrated that its primary objective had not been met. For example, in a comparison with nine similar electric utilities, "the percentage change in PNM's typical electrical bills compares favorably with those of other companies for the 1974-77 period."26 [A] general comparison of PNM's typical bills with those of the nine utilities, however, indicates no significant difference.27

As to improved regulatory efficiency, the report stated, "it would be our opinion that company regulatory activity as indicated by its expenditures for legal and consulting services has substantially increased since the advent of COSI [cost-of-service indexing]. Nor does the Commission appear to have substantial savings although it has been spared any PNM rate case in the 1975 to 1978 period." The report stated further, "there is apparently an increased need for vigilance on the part of the staff and intervenors. This increase, coupled to higher expenditures for regulatory matters by the company prior to and post-COSI, as well as higher cost for the P.S.C., indicates that regulatory savings inherent in the COSI process are speculative and problematic at best."28

In the area of managerial efficiency, the report concluded that while PNM's total factor productivity has improved since COSI was instituted, the increase was primarily due to external factors. Consequently, the NRRI report found that COSI was neither a positive nor a negative influence on managerial efficiency.29

The report was even more critical of the plan's effect on cost of capital. As to long-term debt, their analysis indicated that the effect was minimal since the company had not been earning its rate of return under COSI. The report concluded that it is more important to earn the allowed rate of return than to have COSI or any other mechanism. Their analysis also indicated that there were no significant savings related to preferred stock financing accruing to PNM as a result of the COSI methodology. That is, there was no favorable cost differential between PNM preferred stock sales and those of other electric utility companies. However, the report did conclude that there were some savings in the cost of common equity. Yet, during the 1975-1977 period, PNM's actual rate of return on jurisdictional common equity was consistently below the minimum rate established by the commission.30

The New Mexico Plan may face an uncertain future. By increasing the lag to one year, any advantage to automatic adjustment is mitigated. As stated in the NRRI report, "the ability to earn the allowed rate of return is more important to the financial community than the methods used."31

The president of Public Service Company of New Mexico, Jerry D. Geist, strongly disagrees with the conclusions of the NRRI study. In a speech delivered before the Public Utility Reports Utility Regulatory Conference, Geist stressed that indexing had provided a vehicle for mitigating the most serious defects of regulatory lag and
was invaluable in improving the financial integrity of his firm.

The company estimates that the total capital cost savings, including savings on long-term debt, deferred stock, and common equity, was between $9 million and $16 million for the period 1975 through 1977. The company further estimates that there is a potential savings of $60 million to $100 million through 1982. These claims are coupled with allegations that it was the commission's investigation into the operation of the index that triggered the 1978 decline in PNM's market stock price and price-earnings ratio relative to Standard and Poor's 500 Stock Index. The company further asserts that the relative price improvement the stock is now experiencing reflects the market's recognition of the commission's order to continue the COSI in a modified form.

The company began using the new adjustment clause in May 1979. With additional construction work in progress (CWIP) in rate base, coupled to the calculation of the index based on year-end common equity (in contrast to the former practice of no CWIP on generating equipment and calculation based on average common equity for the year), the company claims it is better off under the new plan. For example, the company made a comparison between revenues that would have been collected in 1979 under the old quarterly index and the revenues that will be collected through the new annual index. The former would have collected about $7 million less. Thus, the company claims the new method, although it appears to be less desirable than the former, does provide an effective method of maintaining the company's financial integrity.30

In spite of the company's enthusiasm, it is doubtful that the plan will continue over the long run in its current form. The regulatory agency does not appear to be saving time or resources nor does the company. It would appear that the regulatory agency has become overwhelmed by the plan's monitoring requirements, and the utility has been forced to spend additional resources on rate case monitoring requirements. Furthermore, since utilities are filing rate cases more frequently, the plan simply supplants the traditional ratemaking process but does not circumvent the lag inherent in that process. The firm would be much better off filing a traditional rate case with a projected test year than using the COSI plan. Inflation is again the culprit. With continued inflation and the lag built into the plan, added to its retrospective nature, the firm in question may find it extremely difficult to earn its allowed rate of return.

Service-at-Cost Adjustment Clauses

In its present form, the plan does not appear to circumvent the lag inherent in the traditional ratemaking process. This fact, coupled to increased expenses of the utility and the regulatory agency under the plan, leads to the conclusion that Public Service of New Mexico would be better off to seek the plan's demise in favor of the traditional regulatory process using a projected test year.

The Michigan Plan

Recently, the Michigan Public Service Commission initiated an automatic rate adjustment clause for the major investor owned electric utilities in its jurisdiction. Aspects of the plan are similar to the New Jersey Plan of 1973.

The Michigan Plan is made up of three distinct parts. First, a comprehensive fuel and purchased power cost adjustment clause has been in effect since 1976. Under Michigan law, the fuel cost portion of this clause can operate automatically, but the purchased power costs are applied only after monthly public hearings.

To provide a managerial incentive, a self-policing incentive-disincentive provision was introduced by allowing only a 90 percent pass-through of changes from a base level for fuel and purchased power. The 90 percent pass-through is admittedly arbitrary, but the Michigan Public Utility Commission feels it provides a realistic and workable incentive to management. For example, assuming a $100 million increase at Detroit Edison, the nonrecovery of $10 million reminds management that costs have gone awry, but the impact on earnings per share is only about 10 cents. Thus, the 90 percent pass-through is not abnormally punitive, yet the potential for cost savings is tempting and substantial.31

Second, the Michigan Plan provides an "availability incentive clause," put in place in 1977. This incentive provision offers a bonus of 25 basis points to the common equity rate of return for system power plant availability ranging from 90.1 percent to 85.0 percent and a bonus of 50 basis points for power plant availability over 85 percent. There is a neutral zone standard for routine expected availability from 70 percent to 80 percent. The plan provides for a disincentive of 25 basis points for availability below 70 percent.

The commission estimates that an improvement of 5 percentage points in availability, for instance, can save Detroit Edison approximately $12 million. Yet, 25 basis points for Detroit Edison amounts
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...to approximately $5.5 million. Thus, there can be substantial gain both to utility stockholders and consumers. The final portion of the plan, approved in 1978 and put into operation in February 1979, involves the use of an incentive provision that adjusts rates for increases in operating and maintenance expenses other than direct generation expenses by no more than the percentage amount equal to the increase in the consumer price index. The automatic adjustment is to take place annually based on the preceding year's rise in the CPI. With this provision, the three-part program addresses almost two-thirds of a utility's cost of doing business.

The Michigan Plan has its drawbacks, but it does present a refreshing attempt to mitigate the cost-plus nature of regulation. The fuel and purchased power adjustment provisions are a positive step toward an incentive regulatory mechanism. With this clause, changes in fuel and purchased power costs have a continuous impact, both positive and negative, forcing the utilities to bargain effectively. In contrast to most FACs, when fuel costs are reduced, the utility is permitted to keep 10 percent of the cost decreases instead of passing the entire savings on to the consumer. Nevertheless, when fuel costs rise, absorbing 10 percent of the increases encourages management to avoid such increases. The clause is a good one and more straightforward than other complex incentive mechanisms to be discussed in the next chapter.

Another drawback of the plan is demonstrated in the commitment of resources for maintenance. The incentives provided by the plan could cause distortion of resource use if an abnormal amount of maintenance expenditures are committed to keep the plants available. For example, the company could increase its maintenance forces at all plants and maintain full crews at each, 24 hours per day. If full maintenance crews were always on duty, equipment problems could be more readily corrected as they occurred. Furthermore, the company could increase its operating staff at each generating station, permitting closer monitoring and more frequent inspection of the equipment and, thus, early identification of potential problems. An abnormal amount of spare parts could be stocked, to avoid the risk of a stockout that could cause an extended outage. Perhaps, however, resources could best be committed elsewhere resulting in greater efficiencies in another aspect of the business.

The company could discontinue cycling operations, that is, not shut down units completely during periods of low load. A unit with higher fuel costs is normally shut down if the load anticipated for the next several hours can be met by running lower fuel cost units. By cycling the units, additional stress is placed on the equipment and the likelihood of outages is increased. Under the Michigan Plan, a company could not shut down the units with higher fuel costs but rather reduce both those units and the units with lower fuel costs to minimum output levels to serve a given load. This would result in higher fuel expenses but would prevent cycling of units and, thus, reduce the risk of down time.

Furthermore, the company could reduce the rated capability of its major generating units, thus reducing the maximum output at which a particular unit is operating. Running a unit above its nameplate capability places additional stress on the unit and again increases the risk of outage. It is easily demonstrated that if low cost units are often run above nameplate capability, although the risk of an outage increases, the company and its consumers enjoy fuel cost savings. The Michigan Plan may discourage such savings attempts.

The plan also could cause distortion in the purchase of coal. For example, coal with less ash content and other more favorable characteristics is more expensive but reduces maintenance problems and improves boiler availability. A cheaper but lower grade of coal may increase the amount of erosion, slagging, fouling, and plugging of boiler equipment that can increase the potential of forced outages. Note, however, partial pass-through of fuel costs reduces these potential problems.

Finally, the company could reduce interchange sales, thus controlling the additional wear and tear on its units arising from running its equipment to generate energy for those sales. The reduction in...
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interchange sales would have a detrimental effect on both the company and its ratepayers, because those sales are often a source of profits above the line.

In the long run, the company could take other suboptimal steps to increase system availability. Such steps would relate primarily to the design and construction of generating units, for example, the construction of smaller units with lower design pressures and temperatures. Although such units generally have higher availability factors, they tend to have higher heat rates (require more coal per unit produced) and higher capital costs per unit than do larger ones.

Also, additional capital funds could be expended in the construction of redundant systems in the various generating units. Examples are the construction of additional feed water pumps, pollution control equipment, coal handling facilities, or other investments that would make the plant configuration more reliable but more expensive.

This is not to say that the particular firms involved in the Michigan Plan are reacting in the adverse manner described above, but that the potential does exist, and if the factors in the plan are considered for adoption elsewhere, such distortion should at least be taken into consideration.

As stated earlier, system availability has its limitations. Its primary drawback is that it does not consider equipment derating. Within the context of the Michigan Plan, a better measure would be that of equivalent availability. Equivalent availability is defined as

\[
\frac{\text{service hours} - (\text{equivalent forced outage hours + equivalent scheduled outage hours})}{\text{period hours}} \times 100.
\]

This is the preferred method advocated by the Equipment Availability Task Force of the Prime Movers Committee of the Edison Electric Institute. For example, a unit could be substantially dented for environmental or other reasons yet be 100 percent available under the system availability factor measure, whereas under the equivalent availability measure it would perhaps be 50 percent available.

The final portion of the plan, which deals with operating and maintenance expenses, acts to mitigate the effects of interaction on utility earnings and places an annual lid on the amount of such expenses allowed. Tying other operating and maintenance expense recovery to the consumer price index (CPI) provides management with outside "competition." Thus, if management allows costs to increase at a faster rate than the CPI, the utility must absorb increases beyond those allowed. Conversely, if cost increases are kept below the rate of increase in the CPI, the company may keep the excess earnings allowed by the adjustment factor.

In practice, the provision is designed to consider nonproduction operating and maintenance expenses for a base year (the first base year being the test year in the first rate case that institutes an other operating and maintenance expense CPI adjustment clause for a company), increase that amount by the increase in the CPI for the period, convert the results to a per kwh figure by dividing by the kwh sales for the test year, and apply the adjustment to customer billings for the twelve-month period beginning two months later (the calculation is made in December, billing begins in February). Amounts to be recovered above the CPI adjustment must be determined in a formal rate case in which the utility must demonstrate why its expenses are rising faster than the rate of inflation.

In April 1980, the Michigan commission applied an incentive plan to Michigan Bell Telephone Company. The plan, approved to operate for a three-year period, will adjust the CPI increase for productivity changes. First, the annual inflation rate will be calculated using the changes in the CPI. From that calculation, a 4 percent productivity offset will be subtracted. (The 4 percent figure represents Michigan Bell's estimate of its recent productivity growth due to technological improvements and overall increases in operating efficiency, anticipated to continue over the three-year life of the plan.) The result is then multiplied by 90 percent in order to provide a spur to further efficiency.

The following example illustrates the plan:

1. Annual rate of inflation as calculated from the CPI 12.0 percent
2. Less 4 percent productivity offset 8.0 percent
3. Excess inflation (line 1 minus line 2) .90 x 8.0 .72
4. Less multiplier for efficiency 7.28 percent
5. Allowable increase (or decrease) to rates

The initial adjustment will take place in October 1980, based on
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the change in the December-to-December 1978–1979 CPI. Adjustments will continue annually, with the last adjustment in October 1982. At that time, a determination will be made as to the continuation of the plan.24

Evaluation

The service-at-cost concept is currently used in an extremely limited number of cases. One can assume that politically its advocacy is practically impossible. The political environment in which public utility commissions must operate, coupled to legal constraints imposed either through legislation or the courts, places severe constraints on the ability to implement service-at-cost plans. Inflation has been the malady common to this form of adjustment. Today’s inflationary environment, fueled by consumer protest over rate increases, has locked commissions into the traditional time-consuming and costly hearing process, the very objective service at cost seeks to avoid. Furthermore, the concept of managerial efficiency is rather tenuous. In the past, efficiency in regulated industries has been achieved external to the firm through gains in generation productivity and other technical breakthroughs. Since the utility industry is extremely capital intensive, rather than pursuing managerial efficiency through service-at-cost mechanisms, one might better divert attention to factors that would influence efficient construction of additional plant capacity, efficient planning and timing of that capacity, and timely application of new technical innovations. However, the state-of-the-art, as depicted in the Michigan Plan, holds considerable promise for the future role of regulation.

Current Status of the Fuel Adjustment Clause

The use of the operating cost adjustment mechanism, especially the fuel clause, has increased dramatically since 1970. The cost of fuel has exceeded all expectations in the backwash of the Arab oil embargo of 1973. Other factors affecting costs include federal and state policies such as pollution control requirements, increased mining costs due to land reclamation and other changes in mining practices, and employee benefits such as allowances for black lung disease. The reaction of the fuel markets is demonstrated in substantial price increases in coal, oil, and natural gas. To offset these increases, electric utilities have quickly returned to the fuel adjustment clause. However, many of the problems described earlier as to method of calculation, hydro generation, customer classes covered, line losses, and so forth, continue as controversial issues.

Current Use

A recent publication of the National Association of Regulatory Utility Commissioners depicts a survey of fuel adjustment clause use in forty-three states and the District of Columbia. (Portions of this survey are shown in Appendix A.) On the electric side, only Idaho, Montana, Oregon, Utah, Washington, and West Virginia did not permit the use of fuel adjustment clauses. At this writing, Missouri also has suspended its use. It is anticipated, however, that this suspension will be temporary. In addition to these jurisdictions, the Tennessee Valley Authority has recently discontinued use of the fuel adjustment clause.
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Current Issues

Since 1975, a number of states that continue to use the fuel adjustment clause have reevaluated their methodology and application. In the context of the effort by the Connecticut commission in the early 1940s toward uniformity, at least twenty-nine states have followed this route. The primary concern has been the items that are allowed to flow through the automatic adjustment mechanism, the incentive toward managerial efficiency, and the proper audit and control of the fuel adjustment clauses by the regulatory agency. In many instances, this effort toward reform has been mandated by the respective state legislatures.

The passage of the National Energy Act reopened the issue. Automatic adjustment clauses are specifically addressed in the Public Utility Regulatory Policies Act (PURPA) in Section 115 under the heading “Special Rules for Standards.” The primary objective of the rule is to encourage incentives for efficient use of resources, including incentives for economical purchase and use of fuel in electric energy generation. Although the act does not ban automatic adjustments, it does require the state regulatory authority to reevaluate their use at least every four years.

The legal battles of the 1960s have continued in a number of jurisdictions. At the federal level, legislation is introduced periodically to ban FAC use altogether, although these efforts have not been successful to date. The same holds true in a number of state jurisdictions. For example, the Supreme Court of Missouri recently found the fuel adjustment clause to be illegal in that state.

Basic Methodologies

To obtain a better understanding of the fuel adjustment mechanism in the context of current problems associated with its use, let us first examine the basis for its calculation. A fuel adjustment is calculated as an increase or credit in cents per kilowatt hour. There are two basic methods used to arrive at the calculated amount—the cents per million Btu method and the cents per kilowatt hour method.

Description

The cents per million Btu method typically involves an adjustment for each full one cent change per million Btu in the cost of fuel. The conversion of the change in fuel cost to a change in cents per kilowatt hour requires the use of the utility’s heat rate in million Btus per kilowatt hour adjusted for losses to the point of metering. The change in fuel price in cents per million Btu is then multiplied by the heat rate to obtain the adjustment per kilowatt hour. This methodology will be demonstrated with an example shortly.

An alternative is the cents per kilowatt hour method. This involves taking total allowable fuel cost in a given period, dividing by total kilowatt hours sold during that period, and comparing the resultant fuel cost per kilowatt hour to a base figure (already included in the company’s base rate as stated in the FAC). The increase or decrease above the base per unit price is passed on to the consumer through the FAC charge or credit.

The only difference between the two methods is the way the heat rate or thermal-generator efficiency is included. Using the cents per million Btu method, the heat rate is treated as a separate factor. Since the heat rate factor is generally not recalculated each month but taken as fixed from some prior period, this method does not adjust for changes in generation mix or usage. It has been widely used to provide the utility with an incentive to use its most efficient (in terms of the calculated heat rate) generator units for a given load. However, overcollection or undercollection of revenues can result. For example, if more efficient units are used, the utility would collect extra revenues from the FAC.

In contrast, the cents per kilowatt hour method implicitly builds in the heat rate, thus adjusting for changes in efficiency each time (for example, each month) the FAC calculation is made. (The same result could be achieved by recalculating the heat rate each month.) The cents per kilowatt hour method is the one most widely used, and it is used by the Federal Energy Regulatory Commission.

Examples

The following examples will serve to demonstrate a very basic fuel adjustment clause. The illustrations are based on the following information:
1. Base cost of coal is 5 dollars per ton or 20 cents per million Btu.
2. Average heat rate of 14,000 Btus per net kilowatt hour generated.
3. Line efficiency of 90 percent, giving 15,556 Btus (based on 14,000 Btus) per kilowatt hour delivered to consumer.
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4. 200,000 tons of coal burned during the month.

5. 357,000,000 net kilowatt hours generated during month.

6. Coal cost up 25 cents per ton or one cent per million Btu from the base price.

Cents per million Btu method. The energy charge will be increased or decreased at the rate of 0.156 mill per kilowatt hour for each one cent increase or decrease in the price of coal above or below the base price of 20 cents per million Btu. Thus:

\[
\frac{1,000,000 \times 15,556}{1,000,000} = 64.3 \text{kwh/MBtu}
\]

and

\[
\frac{1}{64.3} = 0.156 \text{ mill fuel adjustment per kwh.}
\]

Cents per kilowatt hour method. The energy charge will be increased or decreased by the amount per kilowatt hour obtained when the increase or decrease in the cost of coal per ton multiplied by the tons of coal burned is divided by the net kilowatt hour generation multiplied by the line efficiency. Thus:

\[
\frac{($5.25 - $5.00) \times 200,000 \text{tons}}{357,000,000 \times 0.90} = 0.156 \text{ mill fuel adjustment per kwh.}
\]

The methods in both the above examples provide the same answer. If, however, the actual heat rate had changed during the month, but was not recalculated in the cents per million Btu method, an overcollection or undercollection of revenues would result. Regardless of changes in the heat rate, the cents per kilowatt hour method would continue to track costs.

Note that in the cents per million Btu method the efficiency of the generation process is inherent in the methodology. It is the amount of coal necessary to produce a Btu of heat, translated into kilowatt hours, that becomes a critical factor. If poor quality coal is purchased, it will take more coal to produce a given amount of heat. Thus, management is faced with a trade-off between lower priced coal with less Btu content and higher priced coal with higher Btu content.

The cents per kilowatt hour method, however, does not provide a built-in generation incentive. Under this methodology, regardless of the amount of coal consumed vis-a-vis the number of kilowatt hours produced, the quality of coal, and the specific characteristics of the coal, the increase or decrease in the cost is translated directly to a per kilowatt hour basis. The simplicity and close tracking of cost of the cents per kilowatt hour method are clearly its major advantages.

Problems

The innocent simplicities of the fuel adjustment clause rapidly become snarled when put into practice. Often there is considerable latitude as to what items are allowed to flow through the fuel adjustment clause and the methodologies used to collect and audit associated revenues. As indicated in Appendix A, differences abound among the fuel adjustment clauses approved by various states and even in their use by utilities located in the same state. The following areas are of particular interest.

Cost of Fuel

Traditionally, most fuel clauses simply stated that all costs associated with "cost of fuel" were to be passed through to the consumer by the fuel adjustment mechanism. Cost of fuel could include all charges to FERC Uniform System of Accounts 151, Fuel Stock; 152, Fuel Stock Expenses Undistributed; and 153, Residuals. If the utility had any nuclear fuel generation, Account 120.1, Nuclear Fuel in Process of Refinement, Conversion, Enrichment, and Fabrication, is also included (other nuclear expenses are included in Account 518). Noninventory items associated with the cost of fuel flowed through Fuel Expense Account 501, Fuel Used for Steam Generation, or 547, Fuel Used for Other Generation. These accounts are shown in Appendix B.

The above accounts contain not only the purchase price of fuel but transportation, demurrage, taxes, purchasing expenses, insurance, handling, fuel analysis, unloading, intracompany transfers from one station to another, stores expenses, ash removal costs, and pollution control costs, as well as any other items associated directly or indirectly with the cost of fuel. Therefore, the base cost of fuel has been subject to a wide degree of discretion as to which items can be included.

Recently, however, the fuel accounts that are allowed to flow through the fuel adjustment mechanism have been narrowed by a number of regulatory jurisdictions. At the federal level, the cost of fuel includes only the items listed in the inventory Account 151. This
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limitation restricts fuel cost recovery to only those items that are fluctuating in the outside marketplace, thus conforming to the purpose of automatic adjustment as outlined earlier.

The cost components that the states allow to be collected through the automatic adjustment clause are reproduced from a recent NARUC report in Appendix A. It would appear from this table that nearly every state has limited automatic fuel adjustment to Account 151. Only a few states and the District of Columbia allow costs beyond this account. Included are Colorado, Florida, Kansas, Mississippi, Nevada, New Hampshire, North Dakota, Pennsylvania, South Dakota, Vermont, Wisconsin, and Illinois. (The latter may soon limit its coal adjustment to the 151 account.) Note, however, there may be non-inventory account items, such as natural gas and other fuel stock items, allowed.

Nuclear Fuel, Changes in Generation Mix, Factor Bias

Nuclear fuel, although subject to variation in price in the marketplace, is a relatively stable cost item since it remains in the reactor for an extended period. However, nuclear fuel should be allowed in the fuel adjustment mechanism to remove any bias favoring use of one energy source over another.

If only one source of energy, such as cost related to fossil fuel, were included in the fuel adjustment clause, it could be argued that the utility is biased toward the operation of its fossil fuel plant since the associated fuel costs are recouped each month through the fuel adjustment mechanism. Increases in other fuels can be recouped only through the formal rate case procedure. Also, and most important, changes in fuel mix will result in a mismatch of costs and revenues if all fuels are not included. The reason for this mismatch is shown by the following example.

Assume a test year generation mix of 40 percent nuclear and 60 percent coal, with a base fuel cost per kwh of .2 cents and .8 cents, respectively, for a total cost per kwh of 1.0 cent.

Given a change in generation mix to 20 percent nuclear and 80 percent coal, the cost per kwh would be 1.1 cents and 1.1 cents, respectively, or 1.2 cents total cost. The change from the base fuel cost would be +.1 cent for nuclear and +.3 cent for coal, a total gain of .2 cent.

The total fuel cost recovered is computed as follows:

\[
P(Q)Q = w_1L - w_2F + X + cKs,
\]

where:
- \( P(Q) \) = price per unit as a function of quantity sold;
- \( Q \) = quantity sold;
- \( w_1 \) = weighted unit cost of noncapital inputs excluding fuel;
- \( L \) = quantity of noncapital inputs;
- \( w_2 \) = weighted unit fuel cost;
- \( cKs \) = capital savings.

Fuel Adjustment Clause

The total fuel cost recovered rises when nuclear costs are excluded since the reduction in generation cost resulting from that exclusion is not reflected. However, the three mill increase in coal cost is passed through the FAC. Including both fuels would reflect the three mill change in coal costs and credit the one mill savings in nuclear cost.

A word of caution, however. By including all fuels, the fuel adjustment clause will continue to track costs regardless of generation mix. Therefore, the clause goes beyond its original purpose of mitigating price changes in an outside marketplace by mitigating generation mix changes. Clearly, such changes will affect the price the consumer must pay, and by doing so efficiency incentives are lost.

Although an advantage in tracking costs, mitigating changes in generation mix thus can be considered a disadvantage that may frustrate efforts to build in incentives during the ratemaking process. For example, a rate level may be set at a preselected generation mix to encourage the use of low cost plant. The FAC will offset the incentive whenever generation mix changes. This discussion can be carried a step further by demonstrating the effect on the utility's rate of return as a result of production changes, efficiency in fuel usage, and the effect of capital investments to reduce fuel consumption.

To begin the analysis, consider the following revenue requirement model.

\[
P(Q)Q = w_1L - w_2F + X + cKs,
\]
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\[ F = \text{quantity of fuel inputs}; \]
\[ K = \text{units of plant employed by the firm}; \]
\[ s = \text{allowed rate of return or regulatory constraint}; \]
\[ c = \text{weight cost of plant per unit}; \]
\[ X = \text{cost of rate case}. \]

Rearranging Equation (5.1), the rate of return is isolated:

\[
\frac{P(Q)Q - w_L - w_F}{cK} - X = s. \tag{5.2}
\]

Influences in the revenue picture clearly influence the rate of return \(s\) actually earned. These could be additions or deletions from plant, changes in the cost of plant, rate case expenses, changes in the amount or cost of noncapital inputs, changes in the amount of cost of fuel, and, of course, changes in sales.

Assume changes in fuel cost are subject to the following fuel adjustment model.

\[
P'(Q) = P(Q) + b \left[ w'(F/Q) - w'(F_0/Q_0) \right], \tag{5.3}
\]

where \(b\) = proportion of cost increase passed on to the customer.

Subscript \(t\) denotes the current time, and subscript \(0\) denotes the base period.

The above model is simply a depiction of a cents per kilowatt hour fuel clause as discussed earlier. The model does not account for lags in calculation or billing. If \(b = 1\) (100 percent passthrough), any increase in \(w\) or \(F\) is passed on to the consumer.

The influence on the allowed rate of return actually earned as a result of various cost changes demonstrates the influence of a fuel adjustment clause.

**Base case:**
Assume: \( P_o(Q_o) = .05 \);
\( Q_o = 1,000 \text{ units} \);
\( w_L = .01 \);
\( L_o = 100 \text{ units} \);
\( w_F = .25 \);
\( F_o = 100 \text{ units} \);
\( X_o = 10 \text{ units} \);
\( s_o = 7.3 \text{ percent} \);
\( c_o = 85 \);
\( K_o = 1,000 \text{ units} \);
\( b = 1 \);

demand elasticity = 0 (inelastic).

**Case I:** Increase in fuel use. If fuel use increases to 120 units with no increase in \(Q\), the following result is obtained.

\[
P(Q) = P(Q) + b \left[ w'(F/Q) - w'(F_0/Q_0) \right]. \tag{5.3}
\]

\[
P(Q) = .05 + 1 \left[ .25(120/10,000) - .25(100/10,000) \right] \]
\[
P(Q) = .05 + 1 \left[ .25(.012) - .25(.010) \right] \]
\[
P(Q) = .0505 \]

\[
\left[ P(Q)Q - w_L - w_F - X \right] = s_t \tag{5.2}
\]

\[
s_t = .0505(10,000) - 1(100) - .25(120) - 10 \]
\[
s_t = 7.3 \text{ percent (no effect on rate of return)}. \]

As shown, inefficient fuel use has no effect on the rate of return when an FAC is in effect and the amount of passthrough is not subject to lag.
Case 2: Increase in fuel price, \( w_t = .30 \).

\[
P(Q) = P(Q_o) + b \left[ w_t (F_o/Q_o) - w_o (F_o/Q_o) \right]
\]  
(5.3)

\[
P(Q) = .05 + 1 \left[ .30(100/10,000) - .25(100/10,000) \right]
\]

\[
P(Q) = .0505;
\]

\[
P(Q)Q_o - w_1 L_o - w_2 F_o - X \quad c K_o
\]
(5.2)

\[
s_i = .0505(10,000) - 1(100) - .30(100) - 10
\]

\[
s_i = 7.3 \text{ percent (no effect on rate of return).}
\]

As expected, an increase in fuel price with the FAC in effect has no influence on the rate of return. However, assume a reduction in a non-fuel expense, \( w_2 \), and/or a reduction in the amount of non-fuel expense, \( L \) (for example, maintenance), and an increase in fuel expense.

Case 3: Reduction in non-fuel expense, increase in fuel expense.

\[
P(Q) \text{ increases to } .0505, \text{ and}
\]

\[
w_1 L_o \text{ decreases to } 90.
\]

Therefore,

\[
P(Q)Q_o - w_1 L_o - w_2 F_o - X \quad c K_o
\]
(5.2)

\[
s_i = .0505(10,000) - 90 - .25(120) - 10
\]

\[
s_i = 7.5 \text{ percent (an increase in the earned rate of return).}
\]

This increase demonstrates the incentive to reduce maintenance to the detriment of fuel costs. Even if the savings in maintenance is equal to the cost increase of fuel, the FAC does not adjust for cost savings elsewhere, so rate of return is enhanced.

Case 4: The last option to consider is an investment in capital to reduce fuel expense. Assume a capital investment of 100 with a reduction in fuel consumption of 10 units.

\[
P(Q) = P(Q_o) + b \left[ w_t (F_o/Q_o) - w_o (F_o/Q_o) \right]
\]  
(5.3)

\[
P(Q) = .05 + 1 \left[ .25(90/10,000) - .25(100/10,000) \right]
\]

\[
P(Q) = .4975;
\]

\[
P(Q)Q_o - w_1 L_o - w_2 F_o - X \quad c K_o
\]
(5.2)

\[
s_i = .4975(10,000) - 1(100) - 25(90) - 10
\]

\[
s_i = 5(1,100)
\]

\[
s_i = 0.0663.
\]

Note the earned rate of return falls, since the savings in fuel is automatically passed through but the capital cost is not (although capitalization of allowance for funds during construction would offset the loss). Furthermore, there is a cost associated with incorporating the capital into the rate base in a formal case. Thus, when the rate of return \( s_i \) is restored, revenue requirements will also rise since \( X \) increases as well as \( K \) (assuming no change in \( Q \)).

This discussion will continue later in this chapter and will conclude with specific recommendations for modifying the FAC to mitigate these problems.

Purchased Power

FAC calculation becomes more complicated when one utility purchases power from another. Three types of purchases are in-
In general, electric power purchased under joint ownership or from the utility's own pool is treated as if it were generated by the purchasing utility. Therefore, it is reasonable to pass the associated fuel cost through the fuel adjustment clause as if the plant were owned exclusively by the purchasing utility. In the case of economy power (nonpool purchases where the buyer is replacing higher cost energy), the FERC has allowed the total energy charge (including all operating cost items) to flow through. The ratepayer is charged for nonfuel items but, since economy power is cheaper for the utility than, for example, using a peaking plant or other high cost generation, the ratepayer is benefited. Several state jurisdictions also follow this practice.

Another incentive problem develops in auditing the purchased power to others at the incremental cost of 3 cents per kwh with an average cost of generation at 2 cents. If it sells two units of energy at 3 cents to nonjurisdictional customers and eight units of energy to jurisdictional customers at 2 cents, total revenues collected will be 22 cents. Since revenue requirements under the sale are only 20 cents, the 2 cents extra can be deducted from jurisdictional revenue requirements. This deduction can flow through to the consumer through a reduction in the fuel adjustment clause.

The inclusion of purchased power in addition to nuclear and fossil fuels removes any bias for utilization of the company's own generation. It is simply a make-or-buy decision. If purchased power is excluded, when the utility sells power it includes the associated costs with its FAC but not the kilowatt hours sold. Thus, the resultant charges are computed as though the FAC formula is higher than it would be if such kilowatt hours were included. Conversely, when the utility purchases power under this method it substitutes the lower priced purchased power for higher priced fossil fuel but is unable to recoup any cost associated with the purchase. This may represent a bias to generate rather than buy. Consequently, it is in the public interest to allow purchased power to be included.

Furthermore, including purchased power can be extremely beneficial to jurisdictional customers. For example, assume a utility sells power to others at the incremental cost of 3 cents per kwh with an average cost of generation at 2 cents. If it sells two units of energy at 3 cents to nonjurisdictional customers and eight units of energy to jurisdictional customers at 2 cents, total revenues collected will be 22 cents. Since revenue requirements under the sale are only 20 cents, the 2 cents extra can be deducted from jurisdictional revenue requirements. This deduction can flow through to the consumer through a reduction in the fuel adjustment clause. There are, however, distinct disadvantages to including purchased power in the fuel adjustment mechanism. For example, if a capital-intensive base-load plant is out of service, the utility is either forced into higher cost self-generation or higher cost purchased power. The utility may not have an incentive to repair its base-load plant since the fuel clause is mitigating any penalty associated with the plant's down time. Even when the utility operates on what is referred to as economic dispatch, the incentive is still absent.

Under economic dispatch, the utility must operate the lowest cost generating or purchase alternative in rank order of cost increase. When the fuel adjustment clause contains an economic dispatch rule, the utility has the incentive to operate the most economical plant, but only when the plant is available. (This disadvantage is mitigated by the fact that not all costs associated with purchased power are allowed to flow through the FAC.)
that each transaction or particular purchase was made in the most economical fashion. This concern is mitigated, however, since records at the utility's dispatch center indicate the system $\lambda$ (variable operating and maintenance expenses) at the time of any purchase. The system $\lambda$ can be compared to the cost of purchased power to verify that the purchase was more economical than company generation. This comparison will demonstrate whether the dispatcher was able to purchase at a price lower than the utility's own cost at the time of purchase. Granted, it may or may not have been the most economical purchase available at the time, but at least one is able to verify that the utility purchased at a lower price than it could generate.

As stated earlier, the energy portion of purchased power should be treated the same as any other fuel. In a make-or-buy decision, the utility should be allowed to compare the energy cost of its own generation with the cost external to the firm or pool. In this way, the entire energy cost would be allowed to flow through the fuel adjustment mechanism. However, since the demand or capacity charge and the surcharge often placed by the selling utility on these transactions are not fuel items, they should be excluded. Exclusion serves as a deterrent to inefficient purchases of power.

Such a methodology has an added advantage in the ease of auditing and administration. The utility system $\lambda$ would be compared to the cost of the purchased energy to verify that the purchase was more economical than company generation. Furthermore, one would not be required to examine the records of the selling utility to ascertain that particular utility's fuel cost. Thus, the entire audit activity would take place within the one regulatory jurisdiction.

**Captive Mine Purchases**

A special problem exists when pricing coal purchased from affiliates of electric utilities. There are a number of reasons why utilities are attracted to acquire captive coal properties. In a recent article, Zachariah Alleu identified five.

1. Some coal operators, especially during the tight coal market in 1973-74, walked away from coal supply contracts and left many utilities to fend for themselves in a sky-high spot market. This caused extremely embarrassing problems for the utilities with both their regulatory agencies and their public constituencies.

2. The tightening of air-quality regulations (particularly sulfur emission standards) could, in the short run, only be complied with by shifting from high-sulfur to lower sulfur coals. This, in the East, has meant looking for expensive Appalachian coals of metallurgical or almost metallurgical quality (until recently) in a tight market that was influenced by the strong demand for metallurgical coals. Thus, some utilities have felt that it was essential to acquire control of coals that have been scarce and expensive in the market to assure their availability.

3. The escalation clauses in many coal supply contracts have caused substantial fuel cost increases to utilities. The utilities that passed these cost increases on to their customers have had to defend these rapidly rising costs to the regulators and to the public. The prospect of being able to control these costs and reduce their rate of escalation has attracted many utilities to the acquisition of coal companies.

4. In general, there seems always to have been an uneasy relationship between electric utilities and coal companies. One gets the impression that some utility chief executive officers might have acquired coal properties just to avoid future dealings with coal company chief executive officers.

5. In a limited number of cases, there seems to be a pure profit motive for utilities in acquiring coal properties; that is, utility executives have postulated that they would rather keep "exorbitant coal profits" for their stockholders than give them to others.

In addition to the above, by owning its own coal the utility has control over quality, delivery, and production. In many instances, it can also insulate itself from coal strikes. Perhaps the greatest benefit, however, is that obtained over the long run, since its investment becomes fixed and thus embedded. Consequently, the captive coal can become highly competitive and much lower in price than coal available in the marketplace.

At present, the FERC requires a captive coal utility to furnish actual production cost data on this portion of the business as part of the justification for the fuel adjustment charge. In the past, utilities have often used the prevailing market price for coal (either long-term contract prices or spot market prices). The reasoning here is that the companies feel this is a nonutility business, and it should be subject to the dictates of the marketplace.
However, using a current market price may lead to abuses. For example, prior to 1973, Appalachian Electric Power Company in West Virginia had been using the same price for coal it purchased from its affiliates and its nonaffiliates. This practice provided the company with a windfall profit in 1973 and 1974 when the price of nonaffiliate coal surpassed the production cost of its affiliate's coal. In 1974, the West Virginia Public Service Commission required Appalachian to file a revised fuel adjustment to prevent the firm from recovering more than the actual cost of purchasing coal from its affiliate.

This methodology still may not solve the problem. If the market price falls below the affiliate company's cost, the company would be paying (and recovering through the fuel adjustment clause) an excess amount for fuel in relation to current market conditions. Forcing the affiliate to charge the market price could cause losses and affect the financial status of the parent firm.

Like horizontal integration into other areas, vertical integration into coal can clearly affect the risk posture of the firm. In addition, vertical integration into coal raises doubt as to the internal efficiency of this particular aspect of the business. It may be necessary for the utility to sacrifice what at times appear to be cost savings and keep itself free of the criticism associated with vertical integration. Furthermore, in this age of managerial specialization, it is difficult to assume that the expertise required to operate an electric utility will apply equally to the operation of the coal company. Consequently, it may appear logical to allow each party to do what it does best, requiring the electric utility to limit itself to the utility business and the coal company to operate in its own environment.

The captive coal situation should be dealt with on a case by case basis. It may not be in the best interest for all utilities to venture into this area. Yet, utilities with the financial capability, size, and resources to do so should not be precluded from taking advantage of the cost savings available from captive mine purchases.

Moreover, the captive mine should indeed be captive and included as part of the rate base of the utility and part of the expenses of doing business. The return that the utility should enjoy from this activity must be no greater than that obtained from its normal operations. This does put an added burden on the regulatory agency in that close watch must be made of cost and production relative to what is available in the marketplace. Thus, captive coal should be treated as a special case and an area for close scrutiny but should not be disallowed because of any alleged abuses in the past.

Transportation

Transport costs, although relatively nonvolatile, must be included in the fuel adjustment clause. A primary reason is that the utility must often switch to suppliers located in different areas or may buy from a variety of suppliers at indeterminant times. Consequently, transportation costs vary due to the different distances involved, are generally beyond management control, and, when long distances are encountered, constitute a relatively high portion of the cost of fuel.

In addition, costs often vary due to different transportation modes involved and changes in the various tariffs associated with a particular movement or the variety of sources from which the utility purchases. For example, a utility may use barge and truck as well as rail for the transport of coal. It may switch modes, depending on availability of equipment. The various movements may be under different tariff agreements that expire at different times. Consequently, the amount of increase that can result from the operation of these agreements is not predictable, and the amount of the increase and the time it becomes effective is not uniform among the various tariffs. All of these factors tend to create volatility in expenditures required for transportation.

A failure to include transportation costs in the fuel adjustment clause can work to the detriment of the consumer. For example, if the utility is able to acquire coal from a new source at a lower delivered cost than coal from existing sources, but this new source coal has higher transportation costs, the company may not have the incentive to pursue this purchase if it is unable to recover the transportation portion.

Finally, if transportation is excluded from fuel adjustment recovery, this expense is built into the utility's base rate structure. Depending on the particular rate chosen and the sources of coal and timing of purchase, overcollection and undercollection of revenues can result.

An additional problem occurs when the utility owns its own railroad or railroad equipment. If the transportation is directly owned and controlled, any profit of the affiliate accrues to the parent firm. Thus, there is an obvious concern about the managerial incentive of
the parent firm to bargain in negotiating transportation rate increases. It would appear that it is in the utility's best interest to seek increases in this rate. A number of states have chosen to solve this problem by excluding the transportation cost associated with company owned transport and handling the cost only through the formal rate case process.

It should be noted that by embedding costs in transportation equipment the utilities and, consequently, their customers are ahead during an inflationary period. As with captive coal, it may be in the long-run best interest of the consumer to encourage the utility to integrate vertically into the transport area. Often such vertical integration is necessitated by coal car availability or other factors that influence the operation of the railroad. By owning and controlling the railroad, the locomotives, the cars, or a combination thereof, the utility mitigates part or all of the risk inherent in dealing with an independent railroad. Mitigating such risks can clearly be in the interest of the consumer and, although the situation must be subject to very close regulatory scrutiny, company owned transportation should be encouraged where demonstrated to be in the public interest.

Transportation has recently become a particularly controversial issue in the coal producing states. The issue has been exacerbated by the increasing use of western, low sulfur coal in lieu of local, high sulfur coal. In examining this issue it must be kept in mind that the fuel adjustment clause, if designed to track fuel costs closely, must influence the operation of the railroad. By owning and controlling the railroad, the locomotives, the cars, or a combination thereof, the utility mitigates part or all of the risk inherent in dealing with an independent railroad. Mitigating such risks can clearly be in the interest of the consumer and, although the situation must be subject to very close regulatory scrutiny, company owned transportation should be encouraged where demonstrated to be in the public interest.

The problem is compounded by the difficulty of building and operating scrubbers to use local coal. Due to the high costs involved and the uncertainty of operation, it may be imprudent to install scrubbers on an older plant. The best alternative may be the use of low sulfur coal until the plant is retired and replaced with a unit that can be specifically designed and built for use of local coal. The best managerial decision may be the use of western coal regardless of the influence on the fuel adjustment mechanism. Additional factors concerning this issue will be discussed shortly.

A particularly disturbing current problem involves rapidly escalating railroad transport costs for coal. Often, the agreements between the utilities and the transportation companies are based on escalation clauses that allow transport price increases each year based on indices external to the firm. For example, the escalation can be based on changes in the Association of American Railroads (AAR) index, which includes average costs incurred for materials, wages, fuel, and so forth, from all types of movement, many of which cost more than coal (for example, furniture, appliances, automobiles). Depending on the influence of costs from items relatively expensive to handle and ship, the AAR index may be artificially high. Therefore, its validity is questionable on two counts: (1) the particular railroad involved may not contribute to or incur the costs that make up the index and (2) costs from other types of movement influence the index such that it may be relatively high as to coal movement.

Ben David Shiriak addressed this issue further in a recent article. He concludes that even if costs are built up and allocated to a particular movement, the Interstate Commerce Commission has not taken a sufficiently aggressive role in dealing with coal transportation rates. In developing such rates, Rail Form A is often used as a costing methodology. As described by Shiriak, "Rail Form A (RFA) allocates railroad operating expenses to particular movements on a per ton basis. Variable costs, as the ICC uses the term, include, but are not limited to, costs which change as the volume of service increases or decreases. Categories of variable costs include terminal charges, line-haul costs, and loss and damage expense. Each category has numerous sub-divisions reflecting wages, fuel, switching, maintenance, repairs, and more."

As described by Shiriak, these total costs often double when the fixed additives and rate of return and return bonuses are added in. He also notes that the RFA costing is not analogous to the revenue requirement formula described earlier. It rarely normalizes revenues and expenses for nonrecurring events, or annualizes for new events within a test year, or, for that matter, amortizes certain expenses over several years (the replacement of railroad ties as a maintenance expense item is a prime example). Thus, by no means is Rail Form A similar to the ratemaking process of an electric utility.

Shiriak recommends that to avoid higher rates the electric utilities should become involved in litigation before the ICC, borrowing from their experience before state commissions, and imitate...
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the tactics of consumer groups who frequently oppose them. The utilities should:

1. Insist on full hearing, complete discovery, and cross-examination of all witnesses. Insist further, and be prepared to argue on appeal, that the ICC support its findings with evidence in the record which has been subjected to close scrutiny by the parties. Argue against the incorporation of the results of rule-making proceedings, otherwise, specific issues — such as the rate of return — will be decided outside the context of the individual rate case, and an opportunity lost to rebut these findings.

2. Utilize the same personnel who put on their electric rate cases to analyze the coal rate case as if it were a utility matter.

3. Adopt the revenue requirements approach of a utility rate case. Provide evidence which analyzes the carrier’s entire financial picture. Apply the test-year concept and pro-form revenues and expenses to develop a more realistic picture of railroad net operating income. In particular, annualize the effects of other rate increases granted within the test period.

Coal transportation costs have increased rapidly and in many instances have added significantly to the contribution margin of the railroads. A number of railroad issues must be examined, including the rate of return, the normalization of tax benefits, the deduction of tax benefits from rate base for ratemaking purposes, the amortization of capital and other equipment, and the methodology used to determine variable costs and the costs associated with particular coal movements. A great deal of time and effort has been expended examining the fuel adjustment clause issue. It should be noted that often one-half of the expense associated with coal is simply transportation. Perhaps it would be advantageous for consumer groups, academicians, or other researchers to spend more of their time on the transportation issue. It has become evident that the regulatory jurisdictions must become involved and demand greater justification for cost increases in coal transportation rates.

Methodology

The differences between the cents per million Btu method and the cents per kilowatt hour method have already been discussed. At present, the vast majority of state jurisdictions and the Federal Energy Regulatory Commission use the cents per kilowatt hour method. Only Colorado, Delaware, Hawaii, North Dakota, Vermont, and Wisconsin continue to use the fixed heat rate.

Historically, heat rates have improved with expansion. Thus, the utility with a fixed heat rate had an incentive to use the most efficient plant. This was so because extra revenues could be collected if the utility could “beat” its fixed heat rate. However, heat rate improvement has leveled off and can change radically as plant mix varies in an integrated power network.

Considerable revenue benefits or losses can be experienced depending on the method of heat rate calculation. For example, there can be different time lags for recalculating the heat rate, or the rate could be changed only during a formal rate case. The result is clearly a mismatch of costs and revenues.

The cents per kilowatt hour method may remove any overrecovery incentive, but from the utility standpoint it also would remove the potential for underrecovery. From a financial standpoint, it seems logical to choose the stability (and simplicity) of the cents per kilowatt hour method with its close price-cost match.

Perhaps the simplicity, from a consumer’s point of view, is the strongest argument for the cents per kilowatt hour method. The total cost of the utility for the period are divided by the kilowatt hours sold for the period, providing the charge per kilowatt hour. This is not only easy to understand but also easy to calculate and audit compared to the cents per million Btu method.

Zero-Based Fuel Adjustment Clauses

In previous examples, the FAC tracked and recovered only the incremental change in cost. Under a zero-based fuel clause, again one is concerned with only the incremental change, but the entire amount of the fuel expense, in addition to any amounts for purchased power, nuclear, or other fuels, is flowed through the fuel adjustment mechanism. Thus, the FAC becomes zero based. That is, no base cost of fuel is built into the utilities’ overall base rates. The advantages of a zero-based fuel clause are ease of auditing, the ability to compare total fuel cost of one utility with another, and ease of understanding changes in fuel costs.

Ease of auditing can be explained by following coal through Account 153 as it is expensed to Account 501. One only has to track the total amount cleared as compared to the amount recovered through the FAC. The audit becomes more complicated as other fuels are
added in, but it is not complicated further by subtracting the base cost of each associated fuel.

An advantage of comparing one utility to another as to fuel cost is the pressure on the utility to keep cost down when customers can easily compare their fuel bills with those of another utility. The regulatory agency can also use this tool in comparing fuel costs of one utility with similar utilities.

The explanation of differences in the FAC can be seen by keeping in mind that if the FAC is passing through one cent on a base of one dollar, an additional charge of one cent is often interpreted as a 100 percent increase in the FAC, which is true, but is misinterpreted as a 100 percent change in the cost of fuel. By zero basing the fuel clause, the example would be modified, indicating a change from $1.01 to $1.02, less than a one percent increase in fuel cost.

In practice, these advantages are often outweighed by the disadvantages. One must realize that accounting techniques have become highly automated, and ease of auditing should not carry much weight in a decision between a zero-based vis-a-vis a positive based fuel clause. It is a very simple data processing problem. In comparing one utility with another, this is a complex or at best ambiguous advantage since different utilities have different types of generation mix with different heat rates, customer classes, and operating characteristics. Many of these factors are beyond management control. Therefore, if one compares raw numbers of one utility with those of another, the comparison is essentially meaningless. As to explaining the differences in fuel cost, one need only add in the base amount to the amount collected through the FAC.

A key disadvantage is explaining the large amount of fuel that would be shown on the consumer’s bill. Fuel amounts to anywhere from 25 to 50 percent of that bill. To isolate this amount presents a significant public relations problem. States that have tried a zero-based fuel clause have found both the utility and the regulatory agency spending a great deal of time on increased customer complaints. Generally, utilities have shied away from showing any FAC dollar amount on the bill and show only the FAC factor. Furthermore, the fuel adjustment clause is designed to track incremental changes in the cost of fuel. With the zero-based fuel clause, consumers may get the impression the entire cost of fuel is automatically recovered and is not subject to regulatory scrutiny. They may not realize that it is only the incremental change in fuel that is being automatically recovered and is scrutinized in the regulatory process as part of the FAC auditing procedures and/or when it is rolled into base rates during a rate case.

Finally, zero basing the FAC will cause changes in rate structure that may be difficult to justify to the consumer. For example, in an industrial rate schedule, the fixed costs per kilowatt hour are relatively low in comparison to a residential schedule. Removing the fuel cost from the basic rate structure attenuates the differences between the industrial and residential classes. The differences in fixed costs per unit between these two classes have often caused a great deal of consumer concern. That concern may not be cost justified, but by attenuating this difference the controversy would not only continue but also increase. It may be a good practice to zero base the FAC, but the FAC should not be displayed on the customer’s bill in this fashion, for the reasons just discussed.

**Thresholds and Billing Lags**

A threshold is a provision in the FAC whereby the cost increases must reach a certain level before the full increase can be passed on to the consumer. This definition has also been modified to include partial passthrough, whereby only a portion of the increase can be recovered through the fuel adjustment clause.

There are three types of threshold methods: minimum multiplicative increments, neutral zones (sometimes referred to as dead zones), and limited percentage passthroughs. All involve the use of a threshold band in which fuel cost changes are not reflected in the fuel adjustment factor. The first two methods involve narrow fixed bands on the order of one percent, whereby the change in fuel price will not trigger implementation of the FAC. This is a way of buffering minor changes in the cost of fuel. The limited percentage passthrough would allow only partial recovery (for example, 90 percent) of the fuel cost increase to build in an incentive for utilities to reduce costs by attempting to minimize losses. The neutral zone causes the clause to be inoperative unless a specified minimum cost increase or decrease is experienced. The result can be an overcollection or undercollection of FAC revenues.

A threshold method does not match price with cost and in effect builds in a lag delaying full cost recovery, partially defeating the primary objective of the FAC. Furthermore, if cost of fuel is, indeed, beyond management control, partial recovery unnecessarily po-
Billing lags are commonplace with the FAC. These occur when a company is required by the regulatory agency to base its fuel adjustment on cost of fuel incurred in a previous month (referred to as the determination period). The goal has been to encourage management efficiency (the traditional purpose of lag) and/or meet notice and hearing requirements. The traditional disadvantage remains since the lag does not correctly match the cost increase with the price of service.

For example, there is a conflict with seasonal peaks during which the utility experiences higher fuel costs but, due to the lag, cannot recover the cost until after the peak has passed. Not only does the on-peak customer receive a false price signal, but also the utility may not recover all of its costs since energy use has diminished. In addition, the off-peak user is incorrectly charged a higher price based on the cost of fuel during the peak period.

A more subtle type of billing lag is the smoothing technique. This generally involves a three-, six-, or twelve-month arithmetic moving average of fuel costs and/or efficiency factors. The objective is to spread short-run changes in fuel costs or efficiency over time.

A similar effect occurs when the determination period is defined in terms of an arithmetic average of costs incurred in prior months, for example, a determination period based on the average costs from the first two of the prior three months before the billing period. Although these methods lead to more stable and predictable rates, they tend to mismatch cost and price.

Another type of lag involves a limit on the amount of pass-through at any given calculation. The limit in the amount of pass-through (or, in effect, the percentage increase in cost) provides some degree of stability and predictability to the consumer. The limit smooths out any sawtooth effect, that is, significant swings in the FAC over time. Of course, by limiting the amount, there is at times a problem of underrecovery. That problem can be approached through deferred cost accounting, in which costs are deferred until the next FAC calculation and can be recovered at that point. This approach will be discussed shortly.

A shortcoming with any of the above techniques is that the utility is forced to finance, generally on a short-term basis, the cost of fuel during the lag period. Over time this financing can result in additional long-term requirements that would influence the utility's allowed rate of return. This contributes to higher cost of service and higher rates. In addition, an element of uncertainty is not completely mitigated, contributing to risk that will increase the firm's cost of capital.

As an alternative, some states have allowed the use of a projected FAC calculation. In these instances, the utilities are allowed to forecast fuel cost for a period of time (for example, three months) and to reflect such estimated averages of cost in the charge applied pursuant to their FAC. As actual monthly costs become available, any difference between estimated and actual incremental fuel costs are reconciled (rolling reconciliation) and reflected in succeeding applications for change in the FAC.

**Deferred Cost Accounting**

Under deferred cost accounting, the dollars that are allowed to pass through the fuel clause but are unrecovered for any reason are allowed to be recovered in a subsequent FAC calculation. As a result of lags, partial pass-through, or timing differences, not all costs associated with a particular fuel account allowed for pass-through may be recovered based on the determination period used for calculation. Ohio, for example, does not use deferred cost accounting. If a utility does not recover the cost incurred at the time the current FAC calculation is in effect, the dollars are lost.

Under deferred cost accounting, the utility will eventually receive the dollars allowed for pass-through. No legitimate amounts go unrecovered. These costs are deferred until the next FAC calculation and can be recovered at that time. Consequently, one can work with lag techniques as described above to help smooth out fluctuations in the FAC or recover abnormal increases in a more reasonable manner without adversely affecting the financial status of the utility.

Although the earnings of the utility are not adversely affected by lag techniques, managerial efficiency is mitigated to some extent when deferred cost accounting is used. This can be considered a disadvantage.

With the advantages of smoothing techniques and lag techniques coupled to uncertain and escalating fuel prices, deferred cost accounting can prove a useful tool. Overcollection or undercollection of revenues can then be adjusted for in the next calculation period.
However, under this methodology there should be an annual reconciliation of costs and revenues to determine the overrecovery or underrecovery status of the utility. The deferred or overrecovered amounts should not be allowed to become excessive. Not only can excessive amounts adversely influence the financial status of the utility, but also, from a purist's standpoint, it is not good accounting to defer the cost of any commodity that is used daily in the production process and has already been paid for by the utility and then not reflect that expense in current income.

**Annual Reconciliation**

The purpose of annual reconciliation is to reconcile fuel costs and fuel cost recoveries collected through the fuel adjustment mechanism. Through this process one can determine whether the amounts received are in accordance with the amounts allowed for pass-through, and whether the utility is in an overrecovery or underrecovery position.

It is critical in annual reconciliation that one roll back to the utility's last rate case or to the last reconciliation period. In this fashion, one does not build from an underrecovery or overrecovery position. For example, if the reconciliation is based on an arbitrary effective date, at that given instant, the utility may be underrecovering or overrecovering. Yet, a month or two later — depending on sales, cost of fuel, generation mix, purchased power, and so forth — the utility could be in the opposite position. Consequently, it is very important to go back to the last rate case or, once the reconciliation is in place, to the last reconciliation to determine the amount of overrecovery or underrecovery.

During the reconciliation process, several other aspects of the utility's fuel position can be examined — for example, the question of prudent purchase of fuel, the proper auditing of fuel use, fuel contract procedures, as well as other aspects of fuel management. This issue will be taken up again later in this chapter.

**Free Service to Municipalities and Other Nonbilled Energy**

In some states, utilities have customarily provided gas and electricity to municipalities at no cost as a franchise consideration. In light of emerging state and national energy policy, limited supplies of natural gas, and escalating incremental costs for new electric generation, this is an area requiring close examination. In addition, this issue has a special significance in relation to the fuel adjustment clause.

Obviously, the cost of this free service to the municipality varies from month to month as fuel costs change. Unless specific adjustments are made in the methodology, the utilities will be able to pass on these cost changes for the free service to all customers through the fuel adjustment clause. This is unfair to consumers who do not happen to be residents of the municipality obtaining the free service.

A similar problem occurs with other unbilled energy, for example, company use. If such kilowatt hours are not explicitly accounted for in the FAC calculation, the increases in cost associated with such kilowatt hours will be unfairly allocated to the consumer. Other examples of unbilled energy or service not billed on a per kilowatt hour basis include street lighting and traffic signals.

Consequently, the kilowatt hours or therms unbilled to municipalities (as well as other unbilled and flat-billed energy) should be added (an estimate may be necessary) to the kilowatt hours billed when the FAC is calculated. By adding these, the FAC adjustment per unit is reduced in the proper manner.

**Costs Associated with Sulfur Removal**

As discussed earlier, critics often claim that allowing transportation costs automatically to flow through the fuel adjustment mechanism may bias the utility toward using western or other low sulfur coal. This assumption ignores the difficulty of building and operating scrubbers to use local coal. Due to the high cost of their construction and the uncertainty as well as cost of operation, it may be most imprudent to install scrubbers on an older plant. Furthermore, it may be physically or technically impossible to do so. Finally, the generating cost of using local coal with scrubbers may be considerably higher than that of using low sulfur coal without scrubbers. Thus, the best economic alternative may be the use of low sulfur coal until the plant is retired and replaced with a unit that can be specifically designed and built for use of local coal.

Therefore, if faced with a decision between using local, high sulfur coal with scrubber equipment and using western, low sulfur coal, the lowest cost alternative may be selected regardless of the influence of the fuel adjustment clause.

These arguments aside, it may be politically more palatable to
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I.

Costs associated with the scrubber in the fuel adjustment clause are considered. The problem exists since scrubber costs, in contrast to transportation costs, are made up of both capital costs and operating expenses. As the scrubber is being built, it is generally not included in the utility’s rate base, and, even if inserted at the time of a rate case, it (or a portion thereof) remains out of the rate base in the interim. In contrast, the transportation expense as well as the cost of low sulfur western coal slip through immediately in the fuel adjustment mechanism. Consequently, critics claim there is a bias against the use of local, high sulfur coal.

This problem could be solved by including operating costs as well as capital costs associated with the scrubber in the fuel adjustment mechanism. The process would take place as follows. During the construction phase, each month or each time the fuel adjustment calculation is made, the CWIP associated with the scrubber would be inserted into the rate base and rates adjusted accordingly. The increase would be recovered through the fuel adjustment mechanism. When the unit is finished, the capital recovery and associated return cost would be recovered through the fuel adjustment clause. The operating expenses associated with the scrubber would also be recovered. An added advantage would be gained by allowing only the return on the pollution control bonds to be recovered since most costs associated with construction of pollution control equipment are often financed in this manner.

A mitigating factor in following this alternative is the reliability of the pollution control equipment. In practice, the results obtained from this equipment, in some instances, have proven somewhat discouraging, and costs have risen beyond expectation. By allowing immediate recovery through the FAC, the incentive to hold costs down may be aborted. A possible solution would be to encourage the utility to contract with chemical companies to build and operate the scrubber units. A fixed contract with the chemical company would shift the burden to a knowledgeable third party and, perhaps, lessen the magnitude of the problem in the long run.

Uniformity

In an earlier chapter, the attempt by the Connecticut commission to adopt a uniform fuel adjustment clause was discussed. When a uniform clause is adopted, each firm within the particular jurisdiction is required to follow the same format and recover only those fuel costs related items covered by the clause. Consequently, the items that flow through the automatic adjustment mechanism are specified, and the clause is not left for individual company interpretation or design.

A uniform fuel clause attempts to solve, on a jurisdiction-wide basis, many problems associated with the fuel adjustment clause. For example, the cost items to be included are identified, as is the variance or lag period. Different lag periods for each utility result in greater benefits through fuel adjustment to a particular utility over one with a longer lag period. The uniform fuel clause can eliminate this inequity. The methodology also is specified. Consequently, each utility within the particular jurisdiction is on the same footing and is regulated similarly in regard to automatic adjustment.

Above all, a uniform clause is much easier for a commission staff to monitor and audit to assure the consumer is paying only the proper amount. With a number of fuel adjustment clauses in effect in a particular jurisdiction, staff must be intimately familiar with each of the clauses and their associated auditing requirements. Perhaps of greatest concern to the consumer, uniformity brings tighter regulatory control with consistent monthly reporting and auditing methodologies. The uniform clause with specific methodology and includable costs also can provide for standardized periodic verification of operating practices and fuel procurement procedures. The end result, and perhaps the best argument for uniformity, is that the commission staff is able to concentrate its efforts to do a much better job of administering automatic adjustments. Finally, with one uniform clause much of the auditing procedure can be automated at reasonable costs, further strengthening regulatory control over this activity.

At present, twenty-six states have a uniform FAC in effect for all electric utilities under their jurisdiction. Of the states with no uniform fuel adjustment clause, Iowa has recently chosen to adopt one. Kentucky has a uniform clause for generating utilities; Illinois and Massachusetts expect to standardize the various clauses in the near future.

The current move toward uniformity began at the federal level in June 1973 when the Federal Power Commission gave notice of proposed rulemaking in Docket No. R-479 relating to fuel adjustment clauses. In that notice, the commission announced its intention to allow automatic rate adjustments for changes in the cost of nuclear as
well as fossil fuel and also proposed to include the net effect of fuel costs in intersystem exchanges of electric power. It further announced its intention to adjust automatically for changes in the system heat rate by basing the clause on the cents per kilowatt hour method.

After a review of the comments received in response to R-479, the commission issued Order No. 517 on 13 November 1974. This specified a fuel clause of the form:

\[
\text{Adjustment factor} = \frac{F_m - F_b}{S_m - S_b},
\]

where \( F \) = the expense of fossil and nuclear fuel in base period \( (b) \) and current \( (m) \) periods, and

\( S \) = the kilowatt hour sales in the base and current periods.

Furthermore, fuel costs include the actual fossil and nuclear fuel costs associated with electricity purchases in addition to the fuel consumed in the utility's own plant. Sales \( (S) \) are defined as all kilowatt hours sold excluding intersystem sales. If there is any reason billed system sales cannot be coordinated with fuel costs for the filing period, FERC regulations specify that sales may be equated to the sum of generation, plus purchases, plus interchange-in, less energy associated with pumped storage operation, less intersystem sales, less total system losses associated with wholesale sales only.

No specific efficiency requirements are built into the FERC clause other than a two-month lag, that is, the adjustment is based on costs that occurred two months prior to the billing period.

The FERC clause allows only the fuel portion of purchased energy to be passed through. All other costs associated with the sale are excluded. The only exception to this requirement is an "economy" purchase. In that instance, the entire energy charge is allowed. Most states with a uniform fuel adjustment clause have closely followed the above FERC methodology.

**Sales to Other Utilities**

The purchased power issue was discussed earlier in this chapter. For example, in an economy purchase, the price is set at arm's length, often through split savings; that is, if the buyer can produce at \( x \) and the seller can produce at \( x - y \), the price the buyer pays is set in between. Both seller and buyer benefit in that the former is able to sell at higher than generation cost, and the latter is able to buy at less than generation cost. However, purchases by a municipal or cooperative utility from a jurisdictional utility are handled in a different manner from other purchased power.

In sales to cooperative or municipal utilities, the fuel adjustment clause outlined in FERC Order No. 517 is in effect. A special problem exists in dealing with 517 sales. Because of the two-month lag in the FERC clause, the price paid may not be in step with the cost. Thus, the utility's jurisdictional customers may be forced in some cases (depending on the length of the lag) to pay for fuel serving nonjurisdictional customers, that is, the municipal or cooperative utility. This, of course, would not be fair to the jurisdictional consumers.

The following example illustrates the problem. Assume total sales of 100 kilowatt hours, ten of which are sold under the FERC clause and ninety are jurisdictional. The base cost of fuel is one cent per kwh and is increasing at the rate of one cent per kwh per month. Current cost of fuel is three cents per kwh. Thus, the fuel adjustment for the ten FERC sales is two cents per kwh less than for jurisdictional sales. Billing must occur as follows:

<table>
<thead>
<tr>
<th>Sales to Other Utilities</th>
<th>Kwh</th>
<th>Total fuel cost</th>
<th>Base fuel cost</th>
<th>FAC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Under FERC</td>
<td>10</td>
<td>$0.30</td>
<td>$0.10</td>
<td>$0.10*</td>
</tr>
<tr>
<td>Jurisdictional</td>
<td>90</td>
<td>2.70</td>
<td>0.90</td>
<td>1.50</td>
</tr>
<tr>
<td>Total</td>
<td>100</td>
<td>$3.00</td>
<td>$1.00</td>
<td>$1.50**</td>
</tr>
</tbody>
</table>

*Based on 2 month lag.
**$0.10 short fall.

**FAC jurisdiction calculation**

\[
\text{FAC jurisdictional calculation} = \frac{\text{current costs} - \text{base cost}}{\text{current sales}}
\]

\[
\frac{3.00}{10 \text{ kwh} + 90 \text{ kwh}} = 2\frac{\text{¢}}{\text{kwh}}
\]

Note all sales are included, and the two cents are applied to jurisdictional sales. Recall the benefits of sales to nonjurisdictional consum-
Automatic Adjustment Clauses

ers accrue to jurisdictional ones. Short falls from nonjurisdictional customers could also accrue if the above methodology is not used.

One must be careful to allow only $1.80 to flow through to the jurisdictional customer. Short falls from nonjurisdictional customers could also accrue if the above methodology is used.

One must be careful to allow only $1.80 to flow through to the jurisdictional customer. Under no circumstances should the 20 cents be allocated, either through deferred accounting or other means, to the jurisdictional customer.

Line Losses

It takes fuel to supply energy that will be expended in line losses. If the change in the cost of this fuel is not recovered through the fuel adjustment clause, the utility is in an underrecovery position. In effect, by excluding line losses from the FAC calculation, one ends up with a partial pass-through clause. Line losses generally amount to anywhere from 3 percent to 10 percent of energy costs. Therefore, the utility would underrecover cost changes by this range.

Such a partial pass-through, however, may be deliberately built in by excluding line losses to encourage managerial efficiency, that is, to provide explicitly an incentive to purchase fuel in a manner likely to minimize underrecovery.

In adjusting for line losses, it may be tempting to build in different adjustment factors for the various customer classes. Such an adjustment would be theoretically correct since the magnitude of losses varies with the voltage level of service. However, it is more appropriate to reflect such differences in base rate values of each filed tariff rather than complicate the fuel adjustment calculation. With base rate values periodically updated to include the current cost of fuel, the error in the monthly FAC value in relation to line losses will be relatively small.

Line losses can be adjusted for by calculating the fuel adjustment clause based on sales (implicitly building in the loss factor) or by basing the FAC on generation and inserting a loss factor. The differences are discussed below.

Generation versus Sales

Line losses can be built into the FAC in two ways. If one divides cost incurred during the determination period by sales or kilowatt hours billed (and unbilled, to adjust for free service and/or company use), losses are implicitly built in. Thus, cost of fuel properly allocated to sales or kilowatt hours billed will be higher per unit to account for line losses. One can accomplish the same end by dividing cost by kilowatt hours generated and then dividing by one minus a loss factor. For example, if there are 10 percent losses, one would divide costs by one minus .10. Dividing by sales will provide the exact loss factor, while dividing by generation and then adjusting for losses provides only an approximation.

Given this situation, it would seem logical to divide by sales if one wants to build losses in. However, because of cycle billing, sales billed may or may not match generation. Cycle billing occurs because all customers do not have their meters read at the same time, but on different days of the month. This mismatch may result in overrecovery or underrecovery, or in radical swings in the FAC recovery amount per unit. Therefore, because of cycle billing, it would behoove the designer of the clause to use kilowatt hours generated in combination with an explicit loss factor. The net result, depending on the cycle billing arrangement, may be more accurate. Furthermore, if deferred accounting is used, the slight inaccuracy in calculating the loss factor will be adjusted for at the next FAC calculation or as part of the annual reconciliation. In addition, if kilowatt hours generated rather than billed are used, free service and other unbilled energy are automatically adjusted for.

Gross Revenue Taxes

In many states, utility services are subject to gross revenue taxes. Consequently, as the revenues increase because of fuel adjustment, or for that matter decrease because of fuel adjustment, the utility may be in an overrecovery or underrecovery position because of the tax. To adjust for the gross revenue tax in the fuel adjustment formula, simply divide by one minus the gross tax rate in order to build in enough recovery to compensate.

Some jurisdictions have chosen to exclude the gross revenue tax. Consequently, if fuel prices are falling, the utility may overrecover since a fixed level of gross revenue tax is built into base rates. However, if fuel prices are rising, the utility underrecovers, and there is a partial pass-through situation. The overrecovery or underrecovery is deliberately built in as a stimulus to managerial efficiency. This issue will be considered later in this chapter and in the next during discussion of the Connecticut fuel adjustment clause.
Automatic Adjustment Clauses

Pumped Storage

Special consideration must be given to pumped storage hydro­generation when this type of capacity is available. Although the kilowatt hour output from this source is excluded, or included at zero cost, the fuel cost incurred in resupplying the storage reservoir during off-peak hours is passed on to the ratepayer as part of the FAC. This methodology eliminates any double accounting.

Thus, when the utility is consuming kilowatt hours to pump, those are not included in the FAC calculation. Fewer hours lead to higher fuel costs associated with each kilowatt hour that is used. Consequently, the cost of fuel is implicitly built in to resupplying the storage reservoir. When considering output of pumped storage by including the kilowatt hours produced in the calculation without adding to the numerator of the FAC formula, the double accounting is eliminated. Furthermore, by using this methodology, one implicitly builds in the pumping losses. Note, however, that total generation rather than energy billed is used in the FAC calculation, an explicit deduction must be made to account for the kilowatt hours used in pumping.

Inventory Method

Three inventory methods have been used in fuel adjustment clauses. These methods are first-in-first-out (FIFO), average inventory, and last-in-first-out (LIFO). In addition to these three methods, a case has been built for using next expected replacement or next in-first-out (NIFO). Obviously, the inventory method chosen will influence the rate of recovery under the fuel adjustment mechanism.

As indicated in Appendix A, most states use the average inventory method. It is a straightforward methodology and, thus, administratively easier to handle than the other methods; and it does build in an amount of lag to the recovery, aiding in the managerial incentive area. The reason for the fuel adjustment clause is that fuel prices are varying in the marketplace. It is reasonable to assume that an average of the variation over time is fairly close to the amount actually spent for fuel. Thus, under the average inventory method, the deferred account would not become overly burdensome and, if deferred accounting is not used, average recovery over time will remain within reason. There may be extreme cases where faster recovery is required, but these situations can be handled in a formal rate case procedure with greater allowance for working capital. Note, however, that because of tax law requirements the utility may be locked into a particular inventory method and not be allowed to change.

Inventory Adjustments

From time to time it may be necessary to adjust the FAC for miscalculations in inventory. When an inventory adjustment is made on a deferred accounting basis, the adjustment is made in the amount of the deferred account. This adjustment could be an increase or decrease. Thus, the benefit or cost of the inventory adjustment is shifted to the consumer as the deferred account is drawn down.

If deferred accounting is not used, the amount of the inventory adjustment will pass through at the next calculation. However, it may be reasonable in making an inventory adjustment to pass the adjustment through over a longer time, thus creating a need for a special deferred account.

It is important that inventory adjustments be made on a periodic basis to keep the effects of the adjustment within reasonable bounds. It would be prudent to require at least a semiannual review of inventory status.

Nonmonetary Interchanges

In a purchased power situation, money often does not change hands. Power is simply transmitted to the purchasing utility with the idea that the same amount of power will be transmitted back at some later date. Such a transaction is referred to as a nonmonetary interchange. The process will not affect the fuel adjustment clause if handled properly.

In addressing a nonmonetary interchange, whether under nondeferred accounting or not, one need work only with kilowatt hours generated (does not include the nonmonetary interchange-in) adjusted for losses, rather than with kilowatt hours actually sold. In effect, divide costs incurred by kilowatt hours generated. Under such an arrangement, when the kilowatt hours are transmitted on a nonmonetary interchange-out, the costs associated with those kilowatt hours are built into that month’s fuel adjustment clause. Consequently, the consumer pays for the fuel associated with the nonmonetary interchange at that time. However, when the kilowatt hours...
incurred at that point are divided by kilowatt hours generated (does not include the kilowatt hours received).

The only problem that must be considered is when the interchange does not affect jurisdictional customers, but only nonjurisdictional ones. The interchange must affect only those customers involved. For example, if a FAC is calculated and the jurisdictional customers are charged for the costs incurred in sending the kilowatt hours out, those same customers must receive the benefit when the kilowatt hours come back in.

Test Generation

Before an electric plant is approved for commercial operation, there may be test runs from time to time during the latter part of the construction phase. This test generation produces kilowatt hours that are sold to ultimate consumers. The costs associated with test generation are capitalized as part of the work order for the plant. Therefore, in calculating the cost portion of the FAC, the capitalized costs of the test generation must be ignored. This is accomplished by deducting the kilowatt hours test generated from the denominator of the FAC and excluding the associated costs from the numerator. Thus, the effect of the test year generation does not influence the current fuel clause calculation. (Note that the revenues collected from the rate payer for the kilowatt hours produced through test generation are deducted from the work order.)

Managerial Efficiency

Perhaps the most controversial problem to be discussed here is that of incentives. Much of the serious criticism surrounding the use of the fuel adjustment clause deals with the question of management efficiency and incentives. Its opponents allege the fuel adjustment mechanism discourages hard bargaining for fuel. As with the service-at-cost plans discussed earlier, the lack of built-in incentives does leave the impression of an unconstrained cost-plus environment.

Partially as a result of these criticisms, efficiency was addressed in the National Energy Act. Section 115(e) states:

(1) An automatic adjustment clause of an electric utility meets the requirements of this subsection if

\[\text{Fuel Adjustment Clause}\]

\[\text{(A) such clause is determined, not less than every 4 years, by the State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or by the electric utility (in the case of a nonregulated electric utility), after an evidentiary hearing, to provide incentives for efficient use of resources (including incentives for economical purchase and use of fuel and electric energy) by such electric utility, and}

(B) such clause is reviewed not less often than every 2 years . . . by the State regulatory authority having ratemaking authority with respect to such utility (or by the electric utility in the case of a non regulated electric utility), to insure the maximum economies in those operations and purchases which affect the rates to which such clause applies.

(2) In making a review under subparagraph (B) of paragraph (1) with respect to an electric utility, the reviewing authority shall examine and, if appropriate, cause to be audited the practices of such electric utility relating to costs subject to an automatic adjustment clause.\]

In reading the above provision, one can conclude that a fuel adjustment clause without built-in operating and purchasing incentives is naked and should not be indecently exposed to the public. An obvious solution to the problem is to build both an incentive for operating efficiency and one for economical purchase of fuel into the fuel adjustment clause formula.

Historically, two incentive approaches have been used. The cents per million Btu method discussed earlier is one way to encourage operating efficiency. Although the method has its drawbacks, it fixed heat rate (if set properly) provides the utility with a cash incentive to try to minimize its monetary losses by approaching the heat rate. From a positive standpoint, if the utility is able to exceed the pre-established heat rate, it collects extra revenues through the fuel adjustment clause.

Thus, the cents per million Btu method builds a hard cash benefit and at the same time the harsh reality of a cash penalty if the utility does not consume fuel in the most efficient manner. However, this method solves only the operating efficiency aspects of the National Energy Act goals. The methodology must be coupled to an additional incentive if the prudent purchase objective is to be met. Furthermore, the cents per million Btu method may not be politically palatable since the idea of a cash incentive in the form of collecting extra revenues could meet strong opposition from consumer
groups. Finally, as discussed earlier, in today’s integrated power system heat rates often change on a minute by minute basis depending on power flow conditions, and system heat rate may be beyond management control.

A second incentive has been that of regulatory lag. There is often a built-in lag in the fuel adjustment clause from the time the fuel is purchased until revenues are collected. That is, in contrast to a projected fuel adjustment (as, for example, in Virginia, California, and Indiana), the fuel adjustment clause is based on historic costs. As seen in the discussion of thresholds and billing lags, although the goal is to encourage management efficiency, the lag causes a mismatch between the cost increase and the price of service. The key mismatch occurs in the conflict with seasonal peaks during which the utility experiences higher fuel cost but due to the lag does not recover the cost until the peak has passed. (This conflict can be mitigated to some extent by adjusting the base or seasonal rate.) Thus, the traditional lag serves to encourage management efficiency but may lead to inefficiencies in the cost/price match.

The traditional use of regulatory lag should not be abandoned, however. With lag built into the clause, the utility does have an incentive to bargain for fuel and to purchase in a prudent manner. The utility must carry the cost of the fuel during the lag period, and, in order to minimize its fuel cost recovery losses, it has an incentive to purchase the best quality at the lowest price. Furthermore, the utility has an incentive for efficient generation, for again it must carry the cost of the coal during the lag and, therefore, would want to burn as little coal and to produce as much power from the coal burned as possible. (Note, however, that under deferred accounting the utility eventually does recover all costs. Yet, the lag does delay this recovery and, thus, provides the stimulus for efficiency, although somewhat mitigated.)

A traditional lag built into the clause will meet both FAC efficiency requirements of the National Energy Act. However, a prospective or projected fuel adjustment clause clearly would not, unless coupled to other factors that would promote both generating efficiency and prudent purchase. Such modifications include the partial pass through and recovery based on target efficiency or on plant availability.

Partial pass through, as defined earlier, allows only a fixed percentage of the increase in fuel cost automatically to be flowed through the fuel adjustment clause. As discussed in the Michigan incentive plan (see chapter 4), the percentage pass through is admittedly arbitrary but does provide management with a cash incentive to purchase fuel in a prudent manner in order to minimize its fuel cost recovery losses. The incentive is negative in that it is impossible for the utility to recover all fuel costs, but it provides a stimulus to the utility to hold costs down to minimize the impact of increased fuel costs. Note that under partial pass through, 100 percent of cost decreases are automatically passed through.

Partial pass through can be accomplished, as in the Michigan Plan, by specifically stating a percentage pass through figure, by eliminating line losses, or by not allowing pass through of the gross revenue loss tax. Any of these three methods will accomplish the same end. Note that under deferred accounting one must be careful to ensure that the portion not allowed for pass through is never recovered through the fuel adjustment clause.

The partial pass through concept is relatively simple and easy to administer in relation to other managerial incentive schemes. With it there is no controversy as to the proper heat rate setting, system availability factors, or other efficiency targets to be described shortly. In addition, the incentive is relatively easy for the parties involved to understand, including consumers and state legislators. For these reasons partial pass through, despite its drawbacks, is an effective way to build in an incentive provision.

A strong argument can be made that partial pass through creates both incentives—for prudent purchase and for efficient utilization—outlined in the National Energy Act. The incentive for prudent purchase is obvious. As stated above, management is provided with a cash incentive to minimize its fuel cost recovery losses. The argument made for the traditional lag can also be made for partial pass through, namely, the utility has the incentive to consume as little fuel as possible in order to minimize its monetary losses.

The problem of tracking operating inefficiencies or changes in plant mix was discussed in a previous chapter. The issue was described as a potential disadvantage of fuel adjustment clauses. To offset this disadvantage, a number of states have chosen to limit the amount of pass through in the fuel adjustment clause dependent on power plant availability or availability factor. As discussed under the Michigan incentive plan, availability factor is expressed as a percentage of available hours at a given time divided by the period...
hours. Availability factor can be tied to system-wide availability or certain types of plants. When the availability factor is used and its prespecified targets met, only then can 100 percent of the fuel cost increases be recovered. If the target availability factor is not met, the amount of passthrough is reduced.

As claimed under the Michigan Plan, substantial savings can result when base-load generating plants are available and able to produce power. Without this modification, the utility would be able to pass through the fuel adjustment clause the entire amount of cost changes incurred from operating peaking plants when base-load plants are inoperative. Under this scheme, when the base-load plants are down, the plant availability factor is not met, and only partial passthrough of the increased fuel costs results.

The plant availability factor solves the operating efficiency aspect of the National Energy Act requirements. However, one must fall back to traditional lag, partial passthrough, or some other scheme in order to meet the purchase efficiency aspect of the requirements.

As noted in the discussion of the Michigan Plan, system availability suffers from a number of disadvantages that must be dealt with if the concept is to be effective in fuel adjustment clause design. The first problem is that of definition. It does not make much sense to tie system availability to the entire range of generating equipment available since cycling plant and, clearly, peaking plant are not needed on a continuous basis. If system availability has a role to play, its application should be tied to base-load equipment and not to the overall utility system.

The factor must be tied to economic dispatch. When this is done, if the plant is available and is the lowest cost increment available, economic dispatch requirements would dictate its use. The temptation to operate the plant to keep it available is avoided. Furthermore, the definition should be tied to equivalent availability to account for equipment denaturing. Equivalent availability, discussed under the Michigan Plan, is the preferred method advocated by the Equivalent Availability Task Force of the Prime Movers Committee of the Edison Electric Institute. Under this scheme, if a unit is derated or partially available, it is considered available under a system availability factor but numerically identified as partially available under the equivalent availability definition.

The distortion in resource use in both the short and long run is another potential problem in using availability factors. Reiterating the problems outlined in the discussion of the Michigan Plan, a key issue involves plant and equipment maintenance. To keep the amount of passthrough allowed as close to cost as possible, a company could increase its maintenance forces and have maintenance crews available at each plant around the clock. Equipment problems, thus, could be corrected as they occurred and/or a greater amount of maintenance done during off-peak hours. In addition, increased manpower would permit closer monitoring and more frequent inspection of equipment so that existing or potential problems could be identified early on. Increased manpower could be coupled to an abnormal amount of spare parts inventory to avoid the risk of stockout, which could cause an extended outage.

Other factors include the discontinuance of cycling operations, reduction in the rated capability of major generating stations, or the purchase of higher grade fuel with more favorable combustion characteristics. Such fuel could lead to fewer problems with generating equipment and, thus, greater equipment availability but could be substantially more expensive, thus exacerbating the fuel cost problem. Furthermore, in negotiating for new fuel supplies, a firm may be tempted to increase its quality specifications toward more thoroughly prepared coal, again leading to greater reliability but increased cost.

In the long run, the company could take other suboptimal measures in an attempt to maintain system availability. These steps include the construction of smaller units with lower design pressures and temperatures, the construction of redundant systems, and the purchase of equipment with greater reliability criteria. The increased cost of such plant investments may not match the overall increase in benefits. Yet, the increase may be tolerated to gain the suboptimal benefits of 100 percent fuel cost recovery.

Periodically, major generating equipment is taken out of service for an extended time for major maintenance or a complete overhaul. The extended down time required can significantly influence the availability factor. The designer, in setting the availability factor initially, could take such maintenance into account. However, it would be a significant decision variable and would elicit a plethora of opinions from the utility, consumer groups, the regulatory agency, and other interested parties.

North Carolina and Connecticut have adopted modified availability factors in their uniform fuel adjustment clauses. The
Automatic Adjustment Clauses

Fuel Adjustment Clause

Target plant efficiency is another approach that has been used to limit fuel cost passthrough if a major generating plant is not in service. The provision is similar to that of the traditional cents per million Btus method, in that the generating plant must meet a prespecified target in terms of thermal efficiency in order for the fuel adjustment mechanism to recover 100 percent of the increase in fuel cost.

The basic methodology requires the calculation of an efficiency ratio of the weighted average thermal efficiency of the company's generating facilities in relation to a prespecified norm. The efficiency ratio as a factor is applied to reduce the amount of includable fuel charges resulting from internal generation that are allowed to pass through to the consumer. The ratio is calculated as the weighted average thermal efficiency for company owned generation for the most recent twelve months divided by the established target thermal efficiency for the period in question.

The weighted average thermal efficiency is equal to the net system generation divided by the millions of Btus consumed for the last twelve months, whereas the target thermal efficiency is equal to the same ratio calculated either for a predetermined base period or a hypothetical base period under the assumption that all plants are in operation. The target thermal efficiency certainly is subject to judgment on the part of the parties involved in its determination.

Target thermal efficiency will not meet the complete requirements of the National Energy Act in that it is ineffective as an incentive for fuel procurement since it contains no measurement of cost. Therefore, the method must be coupled with another (or with more than one) incentive to encourage prudent purchase of fuel.

Target thermal efficiency, although rather encouraging in theory, has a number of discouraging drawbacks in practice. For example, the thermal efficiency standard can be affected by economic dispatch. That is, the economic dispatch order may schedule a plant that burns very economical coal but on an inefficient basis. From an economic dispatch point of view, such a plant may be the lowest cost and, thus, the optimal plant to use, but its use may adversely affect the target thermal efficiency value, resulting in a penalty to the utility.

In addition, the target can be distorted by nuclear power or large base-load plants. When such plants are not in service, for whatever reasons, the target value is radically affected. Finally, as with the availability factor, target thermal efficiency has the potential for adverse behavior in maintenance of plant, utility operating practices, and long-run construction decisions. The target thermal efficiency concept will be discussed in greater detail in the next chapter.

Optimizing plant capacity factor is another incentive method for managerial efficiency. As with the other productivity efficiency schemes, not meeting the capacity factor requirement would result in partial passthrough. Capacity factor is defined as the percentage of total generation in a given period divided by the product of the unit capacity and the period hours. The objective of the capacity factor incentive is to encourage the utilization and maintenance of relatively low cost base-load plant. Thus, if a base-load plant were down for some reason, the utility would have a positive cash incentive to return it to normal operation. However, optimizing capacity factor finds little or no application as an objective for any plant other than base-load units. It should not be related, therefore, to total plant capacity factor since excessive utilization of high cost peaking capacity is not to be encouraged.

Optimizing capacity factor does have its disadvantages. For example, an early vintage base-loaded plant often has relatively high fuel costs. The use of a capacity factor incentive may make economy power purchases unattractive if the result would be to diminish capacity factor and, thus, the amount allowed for passthrough. Also, the disadvantages inherent in system availability must be repeated for the capacity factor option, for the same potential distortions are inherent in this methodology.

The stimulus provided through annual reconciliation and the public and regulatory scrutiny of the annual reconciliation hearing also promotes managerial efficiency. It would be in the best interest of any rational utility manager to avoid exposure to the public criticism that certainly would result if the company's performance were judged inefficient in such a hearing. Thus, the periodic scrutiny often associated with the fuel adjustment clause can serve to uncover those utilities whose cost, quality of service, or fuel management practices deviate from industry norms.

A word of caution is in order. Although the promotion of managerial efficiency through the fuel adjustment clause is a noble goal, by isolating a specific item in the overall operation of the firm (in this case fuel), attention to this one item may cause distortion elsewhere,
thus increasing rather than reducing total cost to the consumer. The potential for distortion inherent in many of the schemes outlined above may be tolerated, even if their cost exceeds the fuel expense penalty, so as to avoid reduction in fuel cost passsthrough. Consequently, it may be a wiser course to have a relatively "clean" fuel adjustment clause similar to the FERC one and rely solely on lag, partial passsthrough, and annual reconciliation to meet efficiency requirements. Recall the earlier discussion concerning the FAC's effect on rate of return, changes in fuel mix, and factor bias. By introducing lag and partial passsthrough into the analysis, there is an economic penalty for inefficient management.

Fuel Clause Review

Although not part of the design features of a fuel adjustment clause, a number of jurisdictions and, clearly, the National Energy Act require periodic review of the fuel adjustment mechanism and the revenues collected thereunder. In practice, the efficiency and effectiveness of the clause become directly proportional to the effectiveness of the process for administering it. Uniformly designed adjustment clauses, as discussed earlier, that define specifically those costs allowable for pass through, can provide for timely reporting and review of such costs and for periodic verification of operating practices and procedures of the utility.

To accomplish these objectives, an administrative process must be developed to include the following:

1. Uniform reporting requirements to provide the commission with key data to verify the passthrough charge and monitor the primary variables affecting costs.
2. Clearly assigned responsibility and specific procedure for review and analysis of data reported by the utilities on a timely basis.
3. A comprehensive audit of the operations of the utility under the adjustment clause on an annual basis.
4. A formal review before the commission of the operation of the utility for the purpose of determining compliance with the adjustment clause and determining reconciliation adjustments required.

Each feature of the administrative process should be designed to enable the commission to gather, analyze, and review sufficient evidentiary material to form a conclusion as to the reasonableness and fairness of the adjustment charge calculation and the degree of compliance with the approved adjustment formula authorized in the utility's tariff.

Uniform reporting of key cost recovery and operating data should be required each time a fuel cost calculation is made. Such reporting by the utility will enable the commission to perform a review of the adjustment charge calculation prior to customers receiving billing of the passsthrough. Reports should include cost data as accounted for by the uniform system of accounts, recovery data through billings associated directly with the passsthrough, and quantification of the overrecovery or underrecovery position of the utility for the reporting period and the year to date. In addition, operating data should be supplied, including key system variables such as system heat rate, line losses, sales volumes, mix of fuels, mix of internal and external generation, and plant availability, load, and utilization factors. These system variables should be compared to standards established during a major rate case or generic hearing on the FAC itself.

At least biannually, a commission initiated fuel audit should be performed either by the staff or through independent accounting firms to determine any reconciliation adjustments to be ordered. The audit scope should be comprehensive and address the financial data as well as overall operating performance of the utility.

The financial aspects of the audit should be designed to verify the validity and accuracy of reported costs and recovery data from company source documents, assure the utility has properly applied the computation methodology, and determine the settlement position of the utility as well as quantify the reconciliation adjustments required.

The operating performance review aspects of the audit should be designed to evaluate the utility's policy procedures and controls, particularly in the areas of fuel procurement, system operations, and accounting; review and evaluate fuel contracts; and recommend and qualify, wherever possible, performance improvement opportunities.

The review process can form the basis for an evaluation of managerial efficiency under the operation of the fuel adjustment clause. In this fashion, the firm is under public scrutiny as to its fuel procurement and operating practices. The findings of the review and
audit can provide the basis for evaluating the compliance of the utility with the adjustment clause, determining any overcollection or undercollection, and examining the level of effort involved in the fuel procurement process. The end result could be a refund of overcollected revenues if inconsistencies were found in either the purchase of fuel or the operation of the generating units in the consumption of that fuel. By the same token, undercollected revenues could be ordered recovered if deemed in the public interest.

Evaluation

The use of fuel adjustment clauses in electric utility tariffs has increased with a vengeance since 1970. Their use, a response to fuel costs that are uncertain and steadily increasing, has spread to forty-three state jurisdictions, the District of Columbia, and the Federal Energy Regulatory Commission. Generally, the clauses now are applied to all customer classes.

Current use of fuel adjustment clauses has not been without controversy. The legal battles have been solved to some extent, but legislation at both the state and federal level has been introduced from time to time either to modify the use of the fuel adjustment clause or to ban it altogether. The Public Utility Regulatory Policies Act (PURPA) has focused new attention on the clauses to encourage the efficient use of fuel resources as well as economical purchase and use of fuel in electric utility generation. Finally, since 1975, a number of states have reevaluated FAC methodology and application. The primary concern has been the items allowed to flow through automatic adjustment, incentives toward managerial efficiency, proper audit and control of fuel adjustment clauses by the regulatory agency, and uniformity in their application under a particular jurisdiction.

A number of problems have been addressed due to the recent attention given the fuel adjustment clause. The efforts at the federal level toward uniformity have been followed by the states to some extent and many of the associated problems mitigated or solved.

A great deal of effort has been spent in the proper design, audit, and control of the FAC mechanism. Generally, the states as well as the federal government have attempted to design clauses that closely track changes in fuel costs and in generation mix. All fuels generally have been included to aid in the close tracking of costs as well as to discourage bias toward one fuel over another. Purchased power has been included to aid in the efficient utilization of resources on a regional basis. Purchased power simply provides the utility with the proper incentive toward a make-or-buy decision. Transportation and the local coal issue have become particularly controversial as Environmental Protection Agency requirements have steadily increased. The use of western coal is now widespread but extremely expensive since up to one-half its cost, and in some cases more, is tied up simply in the transport cost.

Perhaps the most controversial issue is that of managerial efficiency. A number of attempts have been made to build in incentives in this area. Methods include partial passthrough, regulatory lag, target thermal efficiency, as well as target capacity factors. Such explicit fuel clause designs are to be encouraged and help disprove the fallacy that fuel adjustment clauses are simply cost-plus regulation.

In considering managerial efficiency, the designer of the fuel adjustment clause must not attempt to insulate the utility completely from external market forces. Partial passthrough, regulatory lag, and efficiency targets serve to encourage management to bargain with its suppliers to make each link in the chain that brings raw fuel to the consumer share in the burden of inflation. By simply passing costs forward through each link to the consumer, there are no explicit incentives to mitigate cost increases. Such a chain of events is intolerable.

It is difficult, if not impossible, to predict how fuel markets will behave in the future. In essence, this is the reason for the fuel adjustment clause — to mitigate this uncertainty. In all likelihood the fuel adjustment clause will remain entrenched in electric utility tariffs. The regulatory agency and the consumer must strive to maintain control over its use. The FAC must not become an institutionalized right of an electric utility, but rather a very special privilege granted under very special circumstances with built-in safeguards to prevent abuses.
Sample Fuel Adjustment Clauses

Recently, a number of state jurisdictions have chosen to revamp their fuel adjustment clauses significantly. California, Pennsylvania, Massachusetts, Ohio, Kansas, Illinois, Michigan, North Carolina, Virginia, New York, West Virginia, Kentucky, and others have taken a fresh look at the fuel adjustment mechanism. In this chapter, the FACs of Ohio, North Carolina, and Connecticut are analyzed in detail.

Ohio

In 1975, the Ohio legislature passed Amended House Bill 579 that mandated a uniform fuel cost adjustment clause for investor owned electric utilities under the jurisdiction of the Ohio Public Service Commission. Coupled to the legal framework set forth in the bill, the Public Utility Commission of Ohio (PUCO) promulgated Rule 26 of the commission's Code of Rules and Regulations in March 1976. It provided working guidelines, requirements, and standards for the quantification, documentation, review, and control of costs allowed to flow through the FAC (now chapter 4901:1-11 of the Ohio Administrative Code). Since that time the commission has clarified and elaborated upon its intentions during various FAC hearings.

The Ohio Uniform Fuel Adjustment Clause is historic in nature; that is, costs either represent actual or estimates of actual costs incurred with adjustment to actual costs as they become available. In addition, the Ohio clause is zero based. The entire amount of the allowable fuel and fuel related charges is passed through. As a result, a utility's base rates do not reflect fuel related costs that are within the scope of the fuel adjustment mechanism.

Similar to the requirements of the FERC uniform fuel adjustment clause, the includable fuel costs are limited only to fuel stock Account 151. Thus, only the direct cost of fuel freight on board (FOB) (note transportation costs are included) at the generating station plus fuel cost attributable to purchased power (Account 535) (note only fuel costs associated with purchased power are included, the entire amount of the energy charge is not), oil (Account 547), and nuclear fuel (Account 518) are built into the clause. Noninventoried fuels such as natural gas flow directly through Account 501.

The Ohio clause has the incentive feature referred to as target thermal efficiency (TTE). The thermal efficiency penalty is designed to reduce the amount that can be passed through when operating efficiency does not meet a predetermined target value.

Specific auditing procedures and formal proceedings separate from rate proceedings are required for the review of cost passthrough under the fuel adjustment clause. Also, provisions are made for reconciliation adjustment and refunds or recovery of costs as a result of such reconciliation. The Ohio uniform fuel adjustment clause formula is shown in Figure 6.1.

```
Figure 6.1. Ohio Uniform FAC Formulas

Energy Sold for resale (Esr)
Esr = generation level kWh associated with monetary sales for resale

Nonjurisdictional Energy Sales (Enjs)
Enjs = generation level kWh sold to nonjurisdictional customers

Efficiency Ratio (R)
R = WATE if < 1.0, otherwise R = 1.0

TTE

Weighted Average Thermal Efficiency (WATE)
WATE = net system generation (last 12 months)

MMBtu consumed (last 12 months)
```
Automatic Adjustment Clauses

1. Target Thermal Efficiency (TTE)
   
   \[ TTE = \text{net system generation (base 12 months)} \]
   
   \[ \text{MMBtu consumed (base 12 months)} + \]
   
   plus or minus subjective judgment adjustment

2. Purchased Power Costs (Cp)
   
   \[ Cp = \text{fuel cost} + \text{net energy charges on economic dispatch transactions} \]

3. Sales for Resale Costs (Csr)
   
   \[ Csr = \text{fuel costs including excess of economic purchase energy costs over sales for resale fuel cost recovery on simultaneous economic dispatch transactions} \]

4. Nonjurisdictional Sales Costs (Cnjs)
   
   \[ Cnjs = \text{actual fuel cost charged to nonjurisdictional customers} + \text{imputed excess fuel costs over actual costs charged} \]

5. Includable Energy (Ei)
   
   \[ Ei = (\text{Ensg + Ep}) - (\text{Esr + E'njs}) \]

6. Net Energy from Internal Generation (Ensg)
   
   \[ Ensg = \text{system (kwh) generation as measured - plant used energy at generating terminals} \]

7. Purchased Energy (Ep)
   
   \[ Ep = \text{kwh received as a result of monetary transactions} \]

Explanation

Energy Sold for Resale (Esr) represents the kilowatt hours sold for resale plus the kilowatt hours of related system losses incurred in their delivery. Kilowatt hours delivered as a result of nonmonetary exchanges of power, and their related system losses are not included in this energy total.

Nonjurisdictional Energy Sales (E'njs) represent the kilowatt hours sold to nonjurisdictional customers plus related system losses incurred in their delivery.

Efficiency Ratio (R) is the factor applied to reduce the amount of includable fuel charges resulting from internal generation which are allowed to be passed through to consumers when the Weighted Average Thermal Efficiency (WATE) for the most recent 12 months divided by the established Target Thermal Efficiency (TTE) for the period is less than a value of one (1). Target Thermal Efficiency (TTE) is the target ratio of kilowatt hours to MMBtu which the WATE must at a minimum equal if all includable fuel charges are to be allowed to be passed through under the clause. It is based primarily upon historical WATE performance over a base 12-month period and adjusted by the commission, if necessary, to take into consideration changes in operating environment characteristics.

Purchased Power Costs (Cp) represent the fuel cost portion of all purchased power plus the net energy charge (incremental operating costs plus profit contribution) portion for purchases made on an economic dispatch basis.

Sales for Resale Costs (Csr) represent the generation level fuel costs associated with sales for resale plus any excess of total energy costs (fuel costs plus net energy charges) on economic purchases, made during the same period, over the fuel costs associated with equivalent sales for resale made on an economic dispatch basis.

Nonjurisdictional Sales Costs (C'njs) represent the actual fuel costs charged to the nonjurisdictional customers plus any portion of fuel costs incurred but not charged to these customers in the amount that the contracted fuel cost rate is less than the rate would be computed to be passed through to jurisdictional customers if this cost difference were not taken into consideration.

Includable Energy (Ei) expressed in kilowatt hours is determined by taking the total of Net Energy from Internal Generation (Ensg) and Purchased Energy (Ep) and reducing this sum by kilowatt hours associated with Energy Sold for Resale (Esr) and Nonjurisdictional Energy Sales (E'njs).

Net Energy from Internal Generation (Ensg) represents total system generation (kwh) less any energy used at plants, including that used for pump storage operations.

Purchased Energy (Ep) represents only that portion of kilowatt hours received as a result of monetary transactions. Kilowatt hours received as a result of nonmonetary exchanges of power are not included.

Formulas

Allowable (Passthrough) Fuel Charge (Ca)

\[ Ca = R(Ci - Cp) + Cp \]

Includable Fuel Costs (Ci)

\[ Ci = (Cf + Cp) - (Crs + C'njs) \]
In monitoring and enforcing the FAC in practice, the commission and its staff have a number of responsibilities. There is a complete annual audit of fuel costs conducted by an independent firm. In addition, each company must file its FAC calculation with the staff on a monthly basis. These calculations are reviewed to detect any erroneous reporting of fuel costs and to verify the arithmetic accuracy of the computations. Finally, there is a formal semiannual FAC hearing.

Since the Ohio uniform FAC was adopted, along with its associated rules, the commission has interpreted and elaborated on its requirements as necessary. Fuel costs associated with test generation as well as any taxes are not included. In addition, all types of fuels are included — nuclear, oil, coal, gas, or other fuels. Purchased power costs have been modified to include not only the fuel used for generation but also, in cases of economy power, the entire energy charge when less than the incremental fuel cost of internally generated energy (economic dispatch is required). In addition, clarification has been made for computing the amount to be deducted from includable costs that relate to nonjurisdictional sales requiring commission affirmation of the rate charged jurisdictional customers for purposes of inputting. The portion of actual costs that relate to line losses associated with delivered energy are not allowed in the Ohio FAC. Furthermore, energy and associated costs resulting from test generation are not includable. Monetary energy purchases have been defined to include any purchase accounted for on a monetary basis. Finally, inventory adjustments that affect fuel consumption for production of electricity can be considered when significance of the adjustment has been shown.

The administrative process of the Ohio uniform FAC is rather extensive. A monthly uniform reporting requirement includes both cost and operational data. In addition, there is monthly compliance testing not only to check the arithmetic accuracy of the firm’s calculation but also to assure that only the proper fuel cost items are being passed through the adjustment mechanism. In addition, there is a special annual fuel audit performed by an independent auditor and subject to commission hearing. In addition to this annual audit hearing, there is another semiannual hearing to monitor FAC activities.

The monthly reporting requirements are also rather extensive. The fuel charge charge and recovery data include cost, the energy charge itself, billings, revenues, and the recovery position of the utility. Includable costs are reported by fuel type, includable energy by source, and billings by customer classification. Furthermore, coal fuel purchases must be reported by type of fuel, supplier, quantity, quality, and total unit price per quantity per MMBtu, FOB mine. Also, transportation data must be separately indicated by mode and cost per unit. At the plant level, the quantity, quality, and cost of the fuel associated with energy output must be furnished on a monthly basis. In addition, the net generation heat rate must be supplied.
inventory adjustments must also be furnished on a monthly basis. In
regard to purchased power, monthly purchase and sale of power
must be indicated by supplier, buyer, and type of power transaction.
Associated with this activity, the quantity purchased and the cost in
terms of fuel, energy, and demand charge must be indicated on a
cents per kilowatt hour basis. Any nonmonetary interchanges must
be indicated in terms of kilowatt hours. In addition, system charac-
teristics such as availability factor, equivalent availability factor, net
capacity factor, equivalent forced outage rate, net heat rate, net gen-
eration, test generation, company use, line loss, jurisdictional sales,
nonjurisdictional sales, load factor, and fuel mix must be indicated on
an annual basis.

Of special interest is the use of the target thermal efficiency ratio.
As defined by the commission's FAC rule, the TTE shall be
the reference measure of an electric utility's thermal efficiency ex-
pressed in terms of net kilowatt hours generated per million Btus of
fuel consumed.

Thermal efficiency is quantified by calculating a ratio determined
by dividing the weighted average thermal efficiency (WATE)
achieved by the TTE. The result represents the thermal efficiency
ratio for the generating system. Consequently, the TTE functions as
an efficiency standard with respect to fuel utilization practices and
represents a standard against which the actual thermal efficiency
achieved can be compared.

The target efficiency contains no unit of cost measure and, there-
fore, cannot serve as a standard or incentive for fuel procurement.
However, since the Ohio uniform fuel adjustment clause is based on
historic cost with a lag, the lag serves as an additional incentive for
prudent fuel procurement, as does the inability to recover system
line losses (partial passthrough).

In calculating the target thermal efficiency, the following compo-
nents are taken into consideration: the net kilowatt hours generated
during a specified twelve-month period; the quantity of MMbtus of
fuel consumed in the same twelve-month period by the same plants;
and the anticipated addition or retirement of generating units within
the system, planned or forced equipment outages, or other signifi-
cant system related conditions.

There are disadvantages in the Ohio FAC methodology. A very
basic problem relates to the lag period. Under the Ohio FAC rules,
each utility is allowed to choose its own; consequently, the length of
the lag varies anywhere from ten days to two months depending on
the company. This deviation from uniformity provides the utility
with a shorter lag with an advantage over the utility with a longer one.

The target thermal efficiency standard can be adversely affected
by economic dispatch. For example, a plant that burns very cheap
fuel on an inefficient basis may destroy the TTE value but from an
economic dispatch point of view may be the optimal plant to use.

The standard is also dramatically affected by nuclear power. If a
nuclear plant is down — for example, a planned outage — the target
thermal efficiency value is radically affected. Furthermore, since nu-
clear plants generally do not operate at a constant level but have a
range of equivalent availability, the TTE can dramatically improve
when the nuclear plant is operating at above normal value. The same
problem can occur to some extent with large base-load coal plants.

It is extremely difficult to estimate a reasonable TTE value.
Members of the Ohio Public Utility Commission staff estimate that
approximately 40 percent of the time in hearings is spent on the
estimation of a TTE value. Furthermore, the staff has found that the
TTE value is extremely difficult for the consumer to understand and
may not be politically acceptable to legislators. Thus, the amount of
time spent on the TTE, the problems inherent in nuclear generation,
and the difficulty of explaining the TTE value to affected parties
have been most discouraging.

In summary, the Ohio FAC has a great deal to offer the regulator
in protecting the public interest. The close regulatory scrutiny in-
herent in the clause goes a long way in mitigating many of the disad-
vantages of automatic adjustment. However, the target thermal effi-
ciency requirement, while an excellent idea in theory, is blunted in
practice due to the dynamics of a heterogeneous generation system.

North Carolina

The electric utility companies in North Carolina have placed
considerable emphasis on nuclear power generation. At present,
over 50 percent of electricity generated in the state is through the use
of nuclear fuel. The generating cost for a nuclear based plant is
relatively low in comparison to coal or oil. Consequently, North
Carolina has designed a fuel adjustment clause that encourages the
use of this low cost fuel.

North Carolina's present formula allows computation of increased
and decreased fuel costs, given a base cost, on a cents per kilowatt hour basis, and the formula is directly applicable to individual kilowatt hour sales. All types of fuel and the fuel cost portion of purchased and interchanged power are included.

The disadvantage of the fuel clause in adjusting for changes in generation mix has been alluded to. When a nuclear plant suffers an outage, the kilowatt hours it would have produced must be replaced by coal- or oil-fired units, resulting in substantial increases in fuel costs. Because of the significant amount of base-load nuclear in North Carolina, the primary trigger for changes in the fuel adjustment charge has been changes in generation mix not due to factors in an outside marketplace. To prevent the fuel adjustment clause from acting as financial insulation from such generation changes, the North Carolina commission designed the fuel clause shown in Figure 6.2.

Figure 6.2  North Carolina Fuel Cost Formula

\[ F = \frac{E - 0.00680T}{S} \times 100 \]

where:

- \( F \) = Fuel adjustment in cents per kilowatt hour.
- \( E \) = Fuel costs experienced during the six months ending with the third month preceding the billing period, as follows:
  - (A) Fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants. The cost of fossil fuel shall include no items other than those listed in Account 151 of the Commission's Uniform System of Accounts for Public Utilities. The cost of nuclear fuel shall be that as shown in Account 518, excluding estimated costs and salvage value associated with reprocessing and disposal of the nuclear fuel and by-products and rental payments on leased nuclear fuel and except that, if Account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account.
  - (B) Purchased Power fuel costs such as those incurred in Unit Power and Limited Term Power purchases where the fossil and nuclear fuel costs associated with energy purchased are identifiable and are identified in the billing statement. Plus
  - (C) Interchange Power fuel costs such as Short Term, Economy and Other where the energy is purchased on economic dispatch basis; costs such as fuel handling, fuel additives and operating and maintenance may be included.
  - Energy receipts that do not involve money payments such as Divers Energy and payback of Storage Energy are not defined as Purchased or Interchange Power relative to the Fuel Clause.
  - Minus
  - (D) The cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.
  - Energy deliveries that do not involve billing transactions such as Divers Energy and payback of storage are not defined as sales relative to the Fuel Clause.

- \( S \) = total kilowatt-hour sales during the six months ending with the third month preceding the billing period.
- \( 0.00680 \) = Base cost of fuel per kwh sold.
- \( T \) = adjustment for state taxes measured by gross receipts: 1.06383.


The key component in the fuel adjustment clause is that base-load nuclear plants must operate at at least 60 percent capacity factor on a system-wide basis in order for 100 percent of the changes in fuel costs to be recovered. The North Carolina commission provided for such a modification in its order dated 21 November 1977 and 9 March 1978. As therein stated, "the Commission concludes that this objective is reasonable and attainable in that 60 percent is near the nationwide average... for nuclear plant(s). The Companies should work toward exceeding this goal on a continuing basis."1

Adjustment is made only after hearings. These hearings are held on a semiannual basis, and adjustment can only be made semiannually. Therefore, in considering the capacity factor as stated in the order, "the Commission concludes that semiannual hearings should be scheduled so that if a company has failed to achieve the objective..."
on both a six-month and 12-month moving average basis, a review will be held for the purpose of examining, in detail, outages which have prevented it from reaching the objective. The commission states further that it "wishes to make it clear to all parties that, once a hearing is triggered and scheduled, the hearing will not be limited to investigating ... poor plant performances. While this will be a central and important matter, the Commission, upon finding from the evidence that outage was caused by imprudent management, shall determine to what extent any resultant excess fuel expenses shall be disallowed as an adjustment to the fuel costs to be charged in subsequent periods. Examination of outages will be limited to the most recent six-month period and this period will serve as the test period for any adjustments needed to be made to rates in the event imprudent management has been shown."2

To prevent undue fluctuation in the FAC, the commission provided for a neutral zone to be built into the fuel cost adjustment rider. The commission stated: "If, however, these filings were made too frequently and in instances where fuel costs were changed only slightly, public misunderstanding would once again result. Thus, the Commission proposes that a narrow bracket or range of slight fluctuations in fuel costs, denominated as a 'dead band,' be established for fuel adjustments within which no action ought to be taken to modify a current fuel adjustment rider."2 With the adjustment made only semiannually, the neutral zone appears unnecessary.

To prevent undue financial harm if fuel costs begin to escalate rapidly on a short-term basis, the adjustment can be made more often than each six months provided that the fuel adjustment charge computed within a three-month base differs from the fuel adjustment charge in effect by more than 0.100 cents per kilowatt hour (one mill per kilowatt hour). Thus, if the fuel adjustment charge computed on a three-month base were more than one mill per kilowatt hour below the effective charge, that charge would be allowed. Hearings are necessary only for increases.

In the semiannual hearings, the commission further ordered that fuel cost riders should be rolled in, that is, all fuel costs should be incorporated in the base tariffs. Thus, in contrast to the Ohio clause, the North Carolina FAC is not zero based. The North Carolina clause was originally designed to be zero based, but this concept was abandoned because of public displeasure with (misunderstanding of) the concept.

Figure 6.3 shows the base-load power plant performance review plan. This plan is put into effect under the following circumstances:

If the nuclear capacity factor for the six months and the 12 months ending with October or April, as appropriate, are less than 60 percent, or upon Motion by the Commission, the Public Staff, or another party, the Commission will automatically review the performance of the system's base load generating plants during the next semiannual fuel adjustment hearing, December or June, as appropriate. Both the Public Staff and the affected utility will be required to present to the Commission an explanation and comments concerning the causes of the low performance and concerning any remedial actions taken. If the Commission finds that responsibility for some or all of the poor performance lies with the utility because of management practices deemed to be imprudent, the Commission may disallow some or all of the cost of the below minimum performance, as appropriate.4

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<td>(a) Every electrical public utility which uses fossil or nuclear fuel, or both, in the generation of electrical power shall, on or before the 25th day of each month, file a Base Load Power Plant Performance Report as required in paragraph (e) below.</td>
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<td>(b) The Public Staff should review the base load unit operating performance.</td>
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<tr>
<td>(c) If the nuclear capacity factors for the six months and the 12 months ending with October or April, as appropriate, are less than 60 percent, or upon Motion by the Commission, the Public Staff, or another party, the Commission will automatically review the performance of the system's base load generating plants during the next semiannual fuel adjustment hearing, December or June, as appropriate. Both the Public Staff and the affected utility will be required to present to the Commission an explanation and comments concerning the causes of the low performance and concerning any remedial actions taken.</td>
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<tr>
<td>(d) If the Commission finds that responsibility for some or all of the poor performance lies with the utility because of management practices deemed to be imprudent, the Commission may disallow some or all of the cost of below minimum performance, as appropriate.</td>
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Figure 6.3
the magnitude of the cost, the minimum capacity level at which nuclear generation “breaks even” with coal-fired generation on an economic basis, prior performance of the unit, the vintage of the units, and the general diligence and responsibility of management. The Commission will also consider other relevant factors suggested by the parties.

(e) Requirements for Base Load Power Plant Performance Report. The following shall be separately reported for fossil generation and nuclear generation.

(1) List each outage during the monthly period and include:
   (i) Duration of each outage,
   (ii) Cause of each outage,
   (iii) Explanation for occurrence of cause, if known, and
   (iv) Remedial action to prevent recurrence of outage, if any.

Note: List scheduled outages before forced outages.

(2) Provide the following information for the monthly period and provide a summary for the three-month, six-month, and the 12-month periods ending with the current month:
   (i) Maximum dependable capacity (MDC) in Megawatts (MW),
   (ii) Hours in period,
   (iii) Megawatt-hours (MWH) generated in the period,
   (iv) MWH not generated due to scheduled outages,
   (v) MWH not generated due to forced outages,
   (vi) MWH not generated due to economic dispatch or other causes, and
   (vii) Total MWH possible in period [(i) x (ii)].

Note: Provide (i) through (vii) in the units required and provide (iii) through (vi) as a percent of (vii).

(3) The base load plants to be included in the report are the following: CP&L: Roxboro, Robinson #2, Brunswick; Duke: Belews Creek, Oconee; VEPCO-Mt. Storm, Surry, North Anna. Subsequent base loaded plants shall be reported beginning with their first full calendar month of commercial operation.


The North Carolina clause presents an excellent tool to build managerial incentives into the FAC. The amount of the lag and the close scrutiny of the consumption of fuel provide management with considerable incentive to purchase fuel on a prudent basis. If costs do begin to rise substantially, an adjustment can only occur after a formal hearing. Thus, the increase does not automatically slip through but is allowed only after careful regulatory scrutiny.

The significant lag and semiannual scrutiny of purchase, along with the operating efficiency incentive, clearly place the North Carolina clause within the goals of the National Energy Act. The plan, however, does have disadvantages. For example, it may at times be more economical for the utility to reduce its nuclear generation and run its fossil units at some minimal level in order to have both the nuclear and the fossil units available for an upcoming higher demand period.

The lag period of six months may seem excessively long, but heavy reliance on nuclear and the provision for relief if costs begin to rise substantially place the lag in a reasonable context. In addition, the length of the lag strengthens the incentive to keep the base-load nuclear plants in operation.

On the whole, the clause is an excellent fuel adjustment mechanism for North Carolina. It may or may not be applicable to other states depending on the generation characteristics and fuel mix available.

Connecticut

The Connecticut fuel adjustment clause goes one step beyond that of North Carolina in building in not only a penalty for inefficiency but also a reward for efficient operation above the norm. This mechanism is built in by designing a target nuclear capacity factor tied to the state’s gross receipts tax.

Connecticut is similar to North Carolina in that there is heavy dependence on nuclear fuel with high cost oil as the alternative. Consequently, when the nuclear plants are down, the fuel adjustment amount can skyrocket in recovering the high cost of substituted oil. To encourage management to keep its nuclear plants operating at relatively high levels, a weighted average nuclear capacity factor on a twelve-month basis is targeted at 70 percent. This factor is built into the utility’s base rates. Furthermore, the gross receipts tax, which at present is 5 percent, is also targeted at the 70 percent nuclear capacity factor and built into the base rates.
Automatic Adjustment Clauses

In designing the fuel adjustment clause, the gross receipts tax is not allowed by state statute for passthrough. Consequently, when the actual nuclear capacity factor falls below the target rate of 70 percent and the utility substitutes high cost oil, only 95 percent of the actual cost incurred can be recovered since the utility is not allowed to recover the 5 percent gross receipts tax. Thus, the utility faces a 5 percent penalty. However, if capacity factors of the nuclear units exceed 70 percent and other plants are not needed, gross receipts fall since low cost nuclear is displacing high cost oil. This savings is passed on to the consumer through the FAC, but the tax associated with the gross receipts, which are pegged at 70 percent capacity factor, does not fall. The utility is allowed to keep such revenues and is thereby rewarded for efficiency.

The commission has built a contingency factor into the fuel adjustment clause to avoid excessive recovery if there is a catastrophic event at a nuclear plant, such as occurred at Three Mile Island. Under most fuel adjustment clauses, if a major catastrophe takes place and a significant amount of base-load plant is lost, the utility could simply pass on the cost of purchased power or substitute peaking plant immediately through the fuel adjustment clause. This is not the case, however, in Connecticut.

To bring any substantial and sustained nuclear outage under the direct influence of commission action, the fuel adjustment clause is modified by a generation utilization adjustment clause (GUAC). For purposes of calculating the GUAC, the nuclear capacity factor is pegged at 55 percent. If a lower capacity factor is achieved, the amount of passthrough will be limited by the GUAC formula. This formula, shown in Figure 6.4, will serve to mitigate any radical increases in fuel adjustment revenues.

The Connecticut fuel adjustment clause, through the operation of the gross receipts tax tied to nuclear plant availability, clearly brings the profit incentive to bear in influencing managerial action. Under normal conditions, management has the incentive to minimize its losses by keeping nuclear capacity factor as high as possible, but at the same time it has the opportunity to earn extra revenues if it exceeds established efficiency levels. This double incentive can be a very valuable regulatory tool with profit acting as the prime motivator.

It is very easy to argue that the Connecticut clause meets the requirements of the National Energy Act. It does, indeed, have explicit built-in incentives for managerial action not only in the operation of its units, but also in the purchase of fuel.

![Sample Fuel Adjustment Clauses](image-url)
Conclusions

The goal of this research has been to examine past and present applications of automatic adjustment clauses in electric utility tariffs as an alternative to traditional ratemaking. The automatic adjustment clause has been used to promote managerial efficiency and/or mitigate cost increases during periods of abnormally high inflation. Three general types of clauses have been used: the sliding scale, service at cost, and operating cost adjustments.

Adjustments based on a sliding scale were designed to reward the firm for its efficiency (as measured by reductions in the price of service to the consumer) by allowing greater profit margins. However, the potential of the sliding scale as a solution to current financial problems and requirements of the electric utility industry is tenuous because of several inherent weaknesses in the methodology. These weaknesses include general inflation and cost increases beyond management control, holding company abuses, rigid rates of return prescribed as part of the formula, gains from productivity increases beyond the company's control, valuation of plant, and price elasticity and/or shifts in demand for electric service. Each of these factors alone or in combination negatively affected the results of the sliding-scale application.

Unlike the sliding scale, the service-at-cost or comprehensive adjustment clause continues in limited application. In its basic form, this clause is designed to act as a cost-plus contract between the utility and the consumer subject to regulatory approval. Under the plan, the utility has prior assurance that if any cost items vary, the service price can be adjusted in direct proportion.

In its modern day form, service at cost has been modified to build in managerial incentives through penalties and rewards. Thus, although the sliding scale is no longer in use, it has been reincarnated to some extent in modifying the service-at-cost concept.

Recent attempts at service at cost have built in external targets or controls to limit recovery. One such attempt involves tying the amount of recovery to external indices, such as the consumer price index. In addition, the concept has been tied to productivity measurements as well as to rate of return incentives. Although its application and modifications have certain drawbacks, service at cost does provide a refreshing attempt to improve the regulatory environment in which a firm must operate.

The most widespread application of automatic adjustment allows electric rates to vary automatically in response to changes in one or more preselected uncontrollable operating cost items, the primary example being the fuel adjustment clause (FAC). The fuel clause was used in the past during brief periods of abnormally high inflation. Its use, however, has increased with a vengeance since the Arab oil embargo of 1973. In addition, FACs have been applied to all customer classes since the early 1970s, in contrast to their previous limited application to large industrial users.

The fuel adjustment clause, although unpopular with many consumers, is necessary to mitigate the continuing volatility and uncertainty experienced by utilities in fuel markets. Without the chilling effect of the FAC, uncertainty coupled to rapid increases in fuel prices would result in an overwhelming number of formal rate applications that would greatly exceed the cost of administering fuel adjustment.

A critical issue concerning fuel adjustment clauses is that of managerial efficiency. Without managerial incentives, the firm appears to be operating under simple cost-plus conditions. It is the conclusion of this research that a special effort must be made to build in managerial incentives when the automatic adjustment clause is being used. Incentives such as traditional lag, partial passthrough, and target efficiency measures can serve to promote public acceptance or at least public tolerance of FAC use. In addition, careful and explicit regulatory review of the FAC can serve to promote both managerial efficiency and public acceptability of the concept.

Finally, the fuel adjustment clause should not serve to preserve the utility's allowed rate of return per se but only to mitigate the
Automatic Adjustment Clauses

The automatic adjustment clause can be a very valuable tool for the regulator. Although many may disagree with the findings and conclusions of this research, it is hoped that this work has added material of substantial value to the debate.
### TABLE 1-1: Structural and Operational Characteristics of Electric Utility FAC

<table>
<thead>
<tr>
<th>State</th>
<th>PSC</th>
<th>Description and Coverage of Fuel Costs</th>
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</thead>
<tbody>
<tr>
<td>Alabama</td>
<td>Average cost of coal, gas, the total cost of purchased power, and other items pertaining to the average cost of fuel.</td>
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<tr>
<td>Alaska</td>
<td>Fuel costs for both current and base periods. Excludes gross receipts tax.</td>
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<tr>
<td>Arizona</td>
<td>Fuel and purchased power costs, i.e., the total of Accounts 501, 518, 536, 547, and 555.</td>
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<tr>
<td>Arkansas</td>
<td>Fossil, nuclear fuel, and purchased power costs. Cost components vary from company to company.</td>
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<td>California</td>
<td>All direct and associated costs of fossil fuel. PLUS - Nuclear costs: nuclear fuel and fuel assemblies, fabrication cost, leased or rented storage and transportation less salvage value. - Geothermal energy costs: unit price of steam plus effluent disposal cost. - Purchased power costs: energy and capacity charges. Excludes all costs relating to company, affiliate or subsidiary-owned transportation (including pipeline) and storage facilities, unloading charges from transportation facilities, tankers under hire or contract which are not actually used, all handling by company, affiliate, or subsidiary employees, transportation beyond the unloading point, operation and maintenance charges related to purchased power, and all costs included in base rates.</td>
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<td>Colorado</td>
<td>Accounts 501, steam power generation — fuel and Account 547, other power generation — fuel. Excludes all costs associated with unloading, handling of stockpiles, fuel treatment, ash disposal and transportation of fuel.</td>
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<tr>
<td>Connecticut</td>
<td>Accounts 501 and 547 cleared from Account 151. PLUS - The cost of fuel attributable to purchased power. LESS - The cost of fuel attributable to power disposed of through sale. Excludes costs of the type cleared from Account 152 and nuclear fuel expense.</td>
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<td>Delaware</td>
<td>Accounts 501 and 547 cleared from Account 151, nuclear expenses directly charged to Account 518, and fuel costs of pre-commercial operations. PLUS - Fossil and nuclear fuel costs associated with energy purchased. - Net energy costs of energy purchases, exclusive of demand charges when such energy is purchased.</td>
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<td>State PSC</td>
<td>Definition and coverage of fuel costs</td>
<td>Amount of time lag in passing fuel costs on to consumers</td>
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<td>Delaware (cont'd)</td>
<td>on an economic dispatch basis. Included may be such costs as the charges as a result of scheduled outage(s), all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy.</td>
<td>None</td>
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<tr>
<td>District of Columbia</td>
<td>Accounts 501, 547, and 555, and costs related to the disposal of ash, handling of fuel and procurement of fuel. Excludes gross receipts tax, fuel acquisition costs, and fuel processing costs.</td>
<td>2 months</td>
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<td>Florida</td>
<td>Accounts 501 and 547 and the fuel cost of purchased power. Excludes fuel handling costs.</td>
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<td>Georgia</td>
<td>Accounts 501, 547, 518, and 555 Excludes fuel handling costs.</td>
<td>3 months</td>
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<td>Hawaii</td>
<td>Purchased fuel costs.</td>
<td>None</td>
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<td>Illinois</td>
<td>Purchased fuel costs, ad valorem taxes on large use rates that are priced close to costs, and gross revenue tax. Cost components vary substantially from company to company. Excludes nuclear fuel expense and the cost of purchased power.</td>
<td>1-3 months</td>
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<td>Indiana</td>
<td>Account 151 for fossil fuel and Account 518 for nuclear fuel (excludes expenses for fossil fuel included in Account 151). PLUS Actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified below. PLUS Net energy cost, exclusive of capacity or demand charges, of energy purchased on an economic dispatch basis and energy purchased as a result of a scheduled outage when the costs thereof are less than the company's fuel cost of replacement net generation from its own system at that time. LESS For fossil and nuclear fuel costs recovered through inter-system sales including fuel costs related to economy energy sales and other energy sold on an economic dispatch basis. Excludes fuel handling costs.</td>
<td>None</td>
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<td>Iowa</td>
<td>Accounts 501 and 547 cleared from Account 151 and Account 518 for nuclear fuel (Excludes any expenses for fossil fuel included in Account 151.) PLUS Accounts 503 and 521, the cost of steam purchased or transferred from another department of the utility or from others under a joint operating agreement.</td>
<td>None</td>
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<td>State</td>
<td>PSC</td>
<td>Definition and coverage of fuel costs</td>
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<td>Iowa (cont'd)</td>
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<td>- Expenses of producing steam chargeable to others, to other utility departments under a joint operating agreement, or for other electric accounts outside the steam generating group of Accounts (Accounts 504 and 522).</td>
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<td>- Account 506, the cost of water used for hydraulic power generation.</td>
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<td>- Actual charges paid for energy purchased under firm power, operational control energy, outage energy, participation power, and peaking power agreements or contracts.</td>
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<td>- Net energy cost of economy energy purchases.</td>
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<td>- Energy revenues to be recovered from deliveries to other utilities.</td>
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<td>Excludes fuel handling costs and the cost of waste disposal.</td>
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<td>Kansas</td>
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<td>Fossil fuel costs in Account 501, nuclear fuel costs in Account 518 and purchased power costs in Account 555 (exclusive of capacity, demand, or other fixed charges). Fuel costs should be reduced by the amount of supplier refunds normally credited to Account 501.</td>
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<td>PLUS: Prescribes range for fuel mix. If actual performance falls beyond the limits, the clause provides for calculation of the adjustment using the limit values rather than actual values.</td>
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<tr>
<td>Kentucky</td>
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<td>Actual cost of fossil fuel consumed in the utility's plants and its share of fossil and nuclear fuel consumed in jointly-owned plants, plus the cost of fuel which would have been used in plants suffering forced generation and/or transmission outages, but less the cost of fuel related to substitute generation.</td>
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<td>- Actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than stated below, but excluding the cost of fuel related to purchases to substitute for the forced outages.</td>
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<td>- Net energy cost of energy purchases, exclusive of capacity or demand charges when such energy is purchased on an economic dispatch basis. Included may be such costs as the charges as a result of scheduled outages and all such kinds of energy being purchased by the buyer to substitute for its own higher energy costs.</td>
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<td>- Fossil fuel cost recovered through inter-system sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis. Excludes fuel handling costs.</td>
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<td>LESS: Actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than stated below, but excluding the cost of fuel related to purchases to substitute for the forced outages.</td>
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<td>PLUS: Prescribes range for fuel mix. If actual performance falls beyond the limits, the clause provides for calculation of the adjustment using the limit values rather than actual values.</td>
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<td>Louisiana</td>
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<td>Actual cost of purchased energy.</td>
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<td>State PSC</td>
<td>Definition and coverage of fuel costs</td>
<td>Amount of time lag in passing fuel costs on to consumers</td>
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</table>
| Louisiana (cont'd) | - Fuel cost of other purchased energy. **LESS**  
                  | - Fuel cost of energy sold outside the jurisdictional system. | 1-3 months                                          | No                                                      | Variable                                      | No                                        |
| Maine            | Cost of fuel used to generate electricity and the cost of purchased power excluding capacity charges. | 1 month                                              | No                                                      | Variable                                      | No                                        |
| Florida          | Account 151 or Account 501 cleared from Account 151 for the fossil fuel, Account 518 for nuclear fuel and fuel cost of purchased power. | 2 months                                             | No                                                      | Variable                                      | No                                        |
| Massachusetts     | Fuel and purchased power costs involving interchange. Excludes gross receipts tax. | 2 months                                             | No                                                      | Variable                                      | No                                        |
| Michigan         | Cost of delivered fuel for the generation of power (for the the FAC and the cost of purchased and interchanged power (power purchased and interchanged power clause). Excludes gross receipts tax, fuel handling costs, and fuel testing costs. | 3 months*                                             | Yes - 90% of costs over base cost for 3 largest utilities | Variable                                      | Plant availability incentive linked to rate of return on common equity. |
| Minnesota        | Account 151 for fossil fuel, Account 518 for nuclear fuel, and Account 555 for purchased power. | 3 months                                             | No                                                      | Variable                                      | No                                        |
| Mississippi      | Cost of fuel used for the generation of power. Excludes nuclear fuel and gross receipts tax. | 2 months                                             | No                                                      | Variable                                      | No                                        |
| Missouri         | Cost of coal used for the generation of power and 85% of purchased power generated only from coal and gas. Excludes the cost of purchased power generated with oil. | 2 months                                             | No                                                      | Variable                                      | No                                        |
| Nevada           | Accounts 501, 547, 555, and income tax accounts 190, 236, 283, 409.1, 410.1, and 411. | 6-9 months                                           | No                                                      | Variable                                      | No                                        |
| New Hampshire    | Cost of fossil fuel and purchased energy. Excludes nuclear fuel expense. | 2 months                                             | No                                                      | Variable                                      | No                                        |
| New Jersey       | Direct cost of fuel, transportation to the point of delivery, purchased power or interchange, revenue automatic FAC taxes and energy losses. | 2 months No Variable No No | Levelized FAC                                           | No                                           | No                                        |
| New Mexico       | Accounts 151 (fuel stock — as used), 120.1 (nuclear fuel), 555 (purchased power expense and interchange sales — fuel expense), and 447 (sales for resale — fuel expense component). | Maximum of 2 months No Variable No No | No - levelized FAC                                        | No                                           | No                                        |
| New York         | Purchased power and sales (mainly economy), the cost of coal burned (excluding coal handling charges), oil burned, gas burned, nuclear fuel amortization (including fuel assemblies, fuel burn-up, fuel reprocessing and plutonium credit), and hydro (normally at zero fuel cost). Excludes coal stores expense. | 1 month No Variable No No | No - levelized FAC                                        | No                                           | No                                        |
| North Carolina   | Account 151 for fossil fuel, Account 518 for nuclear fuel, purchased power fuel costs, and interchange power fuel costs. **LESS**  
                  | - Fossil and nuclear fuel costs recovered through | 3 months*                                             | No                                                      | Variable                                      | No                                        |

*Failure to achieve target nuclear capacity factors triggers review of performance of...
### TABLE A-1 Continued

<table>
<thead>
<tr>
<th>State PSC</th>
<th>Definition and coverage of fuel costs1,2</th>
<th>Amount of time lag in passing fuel costs on to consumers</th>
<th>Fixed limited fuel cost pass-through provision</th>
<th>Method of heat rate utilization (fixed, variable, limit, or target)</th>
<th>Power plant performance incentive feature</th>
</tr>
</thead>
<tbody>
<tr>
<td>North Carolina (cont'd)</td>
<td>Inter-system sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.</td>
<td>4 months</td>
<td>No</td>
<td>Fixed</td>
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<td>Excludes nuclear fuel disposal costs, leased fuel rental expenses, and fuel analysis expense.</td>
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<td>North Dakota Cost of fossil fuel, nuclear fuel, and energy related costs of purchased power.</td>
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<td>Fuel costs of inter-system sales.</td>
<td>1-2 months</td>
<td>No</td>
<td>Fixed</td>
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<td>Excludes coal handling costs.</td>
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<td>Ohio</td>
<td>Direct cost of fuel FOB plant (direct cost of fuel is limited to Accounts 501 and 547 cleared from Account 151).</td>
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<td>Fuel cost attributable to purchased power.</td>
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Table A-1. Continued

<table>
<thead>
<tr>
<th>State PSC</th>
<th>Definition and coverage of fuel costs</th>
<th>Amount of time lag in passing fuel costs on to consumers</th>
<th>Fixed limited fuel cost pass-through provision</th>
<th>Method of heat rate utilization (fixed, variable, limit, or target)</th>
<th>Power plant performance incentive feature</th>
</tr>
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<tbody>
<tr>
<td>South Carolina</td>
<td>Leased nuclear fuel and any fossil fuel expenses in Account 518. PLUS *Purchased power fuel costs such as those incurred in unit power and limited term power purchases where fossil and nuclear fuel costs are identifiable. *Interchange power fuel costs such as short term, economy or other, where the energy is purchased on an economic dispatch basis. LESS *Fossil and nuclear fuel recovered through inter-system sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.</td>
<td>2 months</td>
<td>Yes—90% of costs over base case for one company</td>
<td>Variable</td>
<td>No</td>
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<tr>
<td>South Dakota</td>
<td>Costs associated with fuel consumed for the generation of power, and the fuel component of purchased power costs. PLUS *Cost of fossil and nuclear fuel associated with purchased power which are identifiable. LESS *Cost of fossil and nuclear fuel recovered through inter-system sales.</td>
<td>3 months</td>
<td>None</td>
<td>Variable</td>
<td>No</td>
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<tr>
<td>Texas</td>
<td>Cost of fossil and nuclear fuel consumed. PLUS</td>
<td>3-9 months</td>
<td>No</td>
<td>Fixed</td>
<td>No</td>
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<tr>
<td>Vermont</td>
<td>Excludes line losses and fuel transportation costs after the fuel has been delivered.</td>
<td>3-9 months</td>
<td>No</td>
<td>Fixed</td>
<td>No</td>
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<tr>
<td>Virginia</td>
<td>Fuel costs per Accounts 501 and 547 and purchased power costs per Account 555. PLUS *Net energy cost of energy purchases. (Excludes capacity or demand charges when such energy is purchased on an economic dispatch basis.) *Costs for economy energy purchases and charges as a result of outages. LESS *Cost of energy purchased to substitute for its own higher cost of energy.</td>
<td>Average of 3-5 months</td>
<td>No</td>
<td>Variable</td>
<td>No</td>
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<td>Wisconsin</td>
<td>Accounts 501, 518, 536, 547, and 555. PLUS *Cost of fossil and nuclear fuel recovered through inter-system sales, including fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.</td>
<td>2 months</td>
<td>No</td>
<td>Fixed</td>
<td>No</td>
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<tr>
<td>Wyoming</td>
<td>None</td>
<td>No</td>
<td>Variable</td>
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1. Account numbers refer to expense items defined in either the FERC, NARUC, or individual State Commission Uniform System of Accounts.
2. Minor variations may exist from company to company within each state. These have been noted if determinable from the survey results.
3. Applies to Public Service Co. of Colorado.
4. Applies to the four major generating electric companies.
5. Method varies by company.
6. FAC is based on fuel cost projections, which eliminates time lag. However, reconciliations occur five months after expenses are incurred.
7. Estimated costs are used for private utilities. Cooperatives have a one-month time lag.
8. Maximum allowable heat rate varies for different utilities. Actual performance is not permitted to exceed the limit value. If it does, the commission may require the company to recalculate the FAC using the limit values.
9. Lag correction factor is applied for the three largest utilities.
11. The average by company over the past six months has varied from 18 days to 48 days with an overall average for all companies of 38 days.
12. If company falls below target in kwh/MBtu, FAC formula is fixed at value of target.
151 Fuel Stock.
This account shall include the book cost of fuel on hand.

Items
1. Invoice price of fuel less any cash or other discounts.
2. Freight, switching, demurrage and other transportation charges, not including, however, any charges for unloading from the shipping medium.
3. Excise taxes, purchasing agents’ commissions, insurance and other expenses directly assignable to the cost of fuel.
4. Operating, maintenance and depreciation expenses and ad valorem taxes on utility-owned transportation equipment used to transport fuel from the point of acquisition to the unloading point.
5. Lease or rental costs of transportation equipment used to transport fuel from the point of acquisition to the unloading point.

152 Fuel Stock Expenses Undistributed.
A. This account may include the cost of labor and of supplies used and expenses incurred in unloading fuel from the shipping medium and in the handling thereof prior to its use, if such expenses are sufficiently significant in amount to warrant being treated as a part of the cost of fuel inventory rather than being charged direct to expense as incurred.
B. Accounts included herein shall be charged to expense as the fuel is used to the extent that the balance herein shall not exceed the expenses attributable to the inventory of fuel on hand.

Items
Labor:
1. Procuring and handling of fuel.
2. All routine fuel analysis.
3. Unloading from shipping facility and putting in storage.
4. Moving of fuel in storage and transferring from one station to another.
5. Handling from storage or shipping facility to first bunker, hopper, bucket, tank or holder of boiler house structure.
6. Operation of mechanical equipment, such as locomotives, trucks, cars, boats, barges, cranes, etc.
7. Tools, lubricants and other supplies.
8. Operating supplies for mechanical equipment.
9. Transportation and other expenses in moving fuel.
10. Stores expenses applicable to fuel.

153 Residuals.
This account shall include the book cost of any residuals produced in production or manufacturing processes.

120.1 Nuclear Fuel in Process of Refinement, Conversion, Enrichment and Fabrication.
A. This account shall include the original cost to the utility of nuclear fuel materials while in process of refinement, conversion, enrichment, and fabrication into nuclear fuel assemblies and components, including processing, fabrication, and necessary shipping costs. This account will also include the salvage value of nuclear materials which are actually being reprocessed for use and were transferred from accounts 120.5, Amortization Provision for Amortization of Nuclear Fuel Assemblies. B. This account shall be credited and account 120.2, Nuclear Fuel Materials and Assemblies — Stock Account, shall be debited for the cost of completed fuel assemblies delivered for use in refueling or to be held as spares.

Items
1. Cost of natural uranium, uranium ores concentrates or other nuclear fuel sources, such as thorium, plutonium, and U-233.
2. Value of recovered nuclear materials being processed for use.
3. Milling process costs.
4. Sampling and weighing, and assaying costs.
5. Purification and conversion process costs.
6. Costs of enrichment by gaseous diffusion or other methods.
7. Costs of fabrication into fuel forms suitable for insertion in the reactor.
8. All shipping costs of materials and components, including shipping of fabricated fuel assemblies to the reactor site.
9. Use charges on leased nuclear materials while in process of refinement, conversion, enrichment and fabrication.

555 Purchased Power.
A. This account shall include the cost at point of receipt by the utility of electricity purchased for resale. It shall include, also, net settlements for exchange of electricity or power, such as economy energy, off-peak energy for on-peak energy, spinning reserve capacity, etc. In addition, the account shall include the net settlements for transactions under pooling or interconnection agreements wherein there is a balancing of debts and credits for energy, capacity, etc. Distinct purchases and sales shall not be recorded as exchanges and net amounts merely because debit and credit amounts are combined in the voucher settlement.
B. The records supporting this account shall show, by months, the demands and demand charges, kilowatt hours and prices thereof under each purchase contract and the changes and credits under each exchange of power pooling contract.


1. Each of these balance sheets accounts are, of course, transferred to expense accounts during the accounting period. Accounts 151 Fuel Stock, 152 Fuel Stock Expenses Undistributed, and 153 Residuals transfer to expense accounts 901 Fuel Used for Steam Generation and 547 Fuel Used.
Automatic Adjustment Clauses

for Other Generation. Account 120.1 Nuclear Fuel in Process of Refinement, Conversion, Enrichment and Fabrication, transfers to 518 Nuclear Fuel Expenses. Any or all of the expense items listed in the accounts above are justifiable at the state level depending on state statutes and regulatory approval of the published FAC.

Notes

Introduction
2. Transcript of proceedings before the Illinois Commerce Commission, Docket No. 78-0456 and Docket No. 78-0457, Adoption of Uniform Purchased Gas Adjustment Clause(s) et al., 30 November 1978, p. 70.

Chapter I
9. For example, Wisconsin, New York, Hawaii, and Maryland.
11. Federal Energy Administration, "Capital Needs and Policy Choices in
the Energy Industries,” Project Independence Blueprint, Financial
Task Force Report — Finance, pt. 3, October 1974, p. 17,
15. C. F. Phillips, Economics of Regulation (Homewood, Ill.: Richard D.

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ton, D.C., National Association of Regulatory Utility Commissioners,
1974 (mimeographed).
2. U.S. Congress, Senate, Senator Lee Metcalf speaking for the Amend­
ment of the Consumer Protection Agency Act, S. Res. 158-9, 93rd
Congress, 2nd Sess., 6 July 1974, Congressional Record 120,23421.
3. Re Adjustment Clause in Telephone Rate Schedules (1974) 3 PUR 4th
298.
4. Re New Jersey Bell Telephone Co. (1975) N.J. PUC Docket No. 747-
522.
5. Re Public Service Company of New Mexico (1975) 8 PUR 4th 113.
6. Review and Analysis of the Ohio Fuel Adjustment Clause, prepared by
Touche Ross & Co. for the Office of the Consumer’s Counsel of the
State of Ohio, p. 12.
7. Irvin Bussing, Public Utility Regulation and the So-called Sliding­

Chapter 3
2. Ibid., p. 37.
3. Ibid., pp. 37-38.
4. Ibid., pp. 75-76.
5. Ibid., p. 81.
6. Ibid., p. 87.
7. Ibid., p. 89.
8. Ibid., p. 90.
9. Ibid., pp. 91-92.
Automatic Adjustment Clauses


50. Re New Jersey Power & Light Co. (1930) 82 PUR 554.

51. New Jersey Power & Light Co. (1932) 95 PUR 467.


57. “ Increases in Rates of the Milwaukee Companies,” Electrical World 70 (3 November 1917): 875.


60. “Rate Increase to Follow High Cost of Coal,” Electrical World 71 (2 February 1918): 240.

61. Ibid.

62. Foy, “Cost Adjustment,” pp. 663–64; the interested reader might also see Re Rockford Electric Co. (1917F) PUR 196; and ReMontgomerie & Barre Light and Power Co. (1921D) PUR 145; ReFoy v. Pine Grove Electric Light, Heat & Power Co. (1920B) PUR 380; ReIndiana Service Corp. (1930B) PUR 278; ReWashington Gas Light Co. (1920D) PUR 625; RePublic Service Gas Co. (1920E) PUR 365; and ReMontgomerie and Barre Light & Power Co. (1921D) PUR 145.


64. Trigg, “Escalator Clauses,” p. 964.

65. Re Indiana Service Corp. (1930B) PUR 278.

66. Re Rates & Rate Structures of Corporations Supplying Electricity in City of New York and Surrounding Territory (1931C) PUR 352; also see Re City of Rockport v. Rockport Light & Power Co. (1927E) PUR 470; and ReMontgomerie and Barre Light & Power Co. (1921D) PUR 145.

67. Re Newport Water Corp. (1933E) PUR 1.

68. ReNew York Edison Co. (1935) 10 PUR 244.

69. Paul J. Garfield and Wallace F. Lovejoy, Public Utility Economics


70. ReUniform Fuel Clause for Electric Companies (1934) 54 PUR 57.


73. ReUniform Fuel Clause for Electric Companies (1945) 57 PUR 250.

74. ReEdison Light & Power Co. (1942) 44 PUR 275; also see ReBraz­

75. Re Central Louisiana Electric Co. (1948) 74 PUR 110.


77. Ibid., pp. 138–39.


81. ReCommunity Public Service Co. (1952) 80 PUR 19; also see Re Rochester Gas & Electric Co. (1921A) PUR 415; and ReGeorgia Power & Light Co. (1948) 74 PUR 69.

82. ReHartford Electric Light Co. (1952) 85 PUR 102; also see Re New York Edison Co. (1953) 10 PUR 244; and ReSouthern Utah Power Co. (1940) 77 PUR 109.


84. Re United Ice & Coal Co. v. Pennsylvania Power & Light Co. (1951) 89 PUR 432.

85. ReFlorida Power & Light Co. (1959) 29 PUR 3d 199; also see ReArrangement Electric Co. (1958) 89 PUR 432.


89. Ibid., p. 985.


Chapter 4

4. Re Public Service Co. of New Mexico (1975) 8 PUR 4th 113.
6. Ibid., p. 298.
7. Ibid.
10. Ibid., p. 305.
11. Ibid.
17. Ibid. The inputs include:

1. Real labor cost, obtained by weighing man-hours worked for each of 26 occupational and seniority groups by base period average hourly labor compensation for each group. Construction man-hours are excluded, since the labor cost is capitalized and then becomes part of the capital input.
2. Deflated expenses for "intermediate products," consisting of purchased materials, supplies, and outside services. In the absence of satisfactory price deflators for each of the major groups of intermediate costs, Illinois Bell deflates these expenses by the Wholesale Price Index for industrial commodities.
3. Real capital charges are taken at the base period ratio of pretax income to the real gross stock of capital assets. Real gross capital stock includes gross plant and equipment (before depreciation), cash, net receivables, and inventories of materials and supplies, each expressed in deflated 1967 dollars.
Since the inputs, or real costs, are all expressed in terms of base period (1967) prices, they are additive to total real costs. . . . This 1967 base year is consistent with the base used for most index numbers published by federal government statistical agencies.
19. Ibid., p. 120.
20. Ibid., p. 132.
21. Re Public Service Co. of New Mexico (1975) 8 PUR 4th 113.
22. Ibid.
23. Ibid.
24. Re Public Service Co. of New Mexico, Docket No. 1419, 29 December 1978.
26. Ibid., pp. 28 and 29.
27. Ibid., p. 43.
28. Ibid., p. 56.
29. Ibid., p. 36.
32. Ibid., pp. 13-14.
33. Ibid., pp. 16-18.
Chapter 5


4. See, for example, Western Massachusetts Electric Co. v. Massachusetts Department of Public Utilities (1977) — Mass. —, 366 NE 2d 1232.

5. Rodgers, Pozza, and Burke, State Commission Regulation, pp. 184–95.


8. Ibid., p. 41.

9. Ibid., p. 41.


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2. Ibid.

3. Ibid.

4. Ibid.


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