ELECTRIC FUEL ADJUSTMENT CLAUSE DESIGN

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FOREWORD

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

Douglas N. Jones
Director

EXECUTIVE SUMMARY

This report documents the electric fuel adjustment clause (FAC) practices of the fifty states, discusses aspects of FAC design for promoting efficiency and sets out in outline a model set of procedures for reviewing and monitoring fuel cost changes. Included is consideration of the potential for use of a computerized fuel cost data file for rate change review and approval.

Over the past several years the energy crisis and continuing inflation, along with the concerns of consumer advocates and environmentalists, have combined to focus attention on the design and use of FAC's by electric utilities and state regulatory agencies. While some of the furor is directed at the rising fuel costs per se, much of the debate has been directed toward legitimate concerns regarding the loss of regulatory oversight for rate increases. Advocates of FAC's argue that they are necessary to promote procedural efficiency during periods of inflation: utility earnings are protected without unduly increasing regulatory costs, and the cost of capital may be reduced because of the utility's ability to recover costs without an extended period of regulatory lag. Opponents of FAC's, on the other hand, contend that their use is antithetical to good regulatory practice: utilities may lose all incentive to hold the line on rising fuel costs and may attempt to use the clause to flow through to consumers various non-fuel-related expenses, and at any rate FAC's place undue emphasis on a single expense item.

As of late 1978, 44 of 51 state regulatory agencies, including the District of Columbia, allowed FAC's to be used by the regulated electric utilities. In an increasing number of states, rate changes are not automatic but require a hearing for approval of the change; at this time 15 states require a hearing.

When FAC's are judged to be necessary, careful attention to FAC design can contribute to the elimination of potential abuses in FAC practices without sacrificing to a great extent the procedural efficiency that motivates FAC usage. FAC design considerations include (a) use of an arithmetic formula which provides for rate changes to follow fuel price changes in a way that does not allow extra revenue recovery to exceed extra fuel costs, and (b) precise definition of includable expenses and specification of expenses that must be excluded. Also, a well designed FAC should not encourage inefficient substitution of fuel for non-fuel expenses, and vice versa.

State agency acceptance of a fuel adjustment clause may require that the agency take steps to assure the public that the utility actively opposes fuel price inflation. There are two approaches for accomplishing this, the incentives approach and the monitoring approach.

The incentives approach builds into the FAC formula a reward for good performance and/or a penalty for poor performance. The reward or penalty can deal with either the amount of revenue recovery or its timing. Incomplete recovery of fuel cost increases is an example of this approach. Alternatively, power plant productivity measures may be linked to efficiency incentives.

The monitoring approach calls for increased regulatory oversight of fuel acquisition, utilization and billing practices of electric utilities. For effective monitoring, the following administrative processes are recommended: reporting, review, audit, and hearing. Uniform reporting requirements provide the regulatory agency with key data needed to verify the FAC rate change calculation and to monitor the primary variables affecting system fuel costs. Review of submitted data is the actual check by the agency on the calculations and the fuel cost variations. The audit is a periodic and comprehensive analysis of the operations of the utility under the FAC, probably best conducted on an annual basis. The formal hearing is a review, before the commission, of the operation of the utility for the purpose of determining compliance with the adjustment clause and determining any reconciliation adjustment required.

Both the incentives and monitoring approaches are recommended. With a properly designed FAC a regulatory agency may rely primarily on built-in incentives to hold costs down and may employ a minimum of monitoring procedures. However, at least some monitoring is required to assure utility compliance with the terms of the clause.

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CHAPTER 1
INTRODUCTION

Background

Fuel Adjustment Mechanisms Defined

Fuel adjustment mechanisms first were used in the United States during World War I to allow the regulatory process to function although there was a rapid unchecked increase in coal prices throughout the period. A definitive study of the origin of these mechanisms is found in Trigg.[1]

An automatic adjustment clause is a tariff provision, approved by the regulatory commission in advance, whereby a change in a preselected cost item or items will automatically permit a change in rates without formal regulatory hearings.

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

Automatic adjustment serves to recover or refund expenses pursuant to an approved formula without the necessity of a formal rate case, thus

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[1] R. S. Trigg, "Escalator Clauses In Public Utility Rate Schedules," University of Pennsylvania Law Review, 106 (1958) pp. 964-97.

easing the administrative burden, reducing regulatory lag, and reducing both the company's and the commission's regulatory costs. In addition, the automatic adjustment clause can, in theory, mitigate risk and thus reduce the cost of capital to the firm. Such capital cost savings during periods of heavy construction and financing burdens may more than offset the entire amount of the adjustment revenues.

Two requirements are generally inherent in automatic adjustment provisions: first, the expense for which automatic adjustment is sought should be relatively uncontrollable expense. Second, the expense should bear a direct relation to the volume of business done; otherwise cost allocation is difficult, arbitrary and the adjustment cannot be made so as to recover for the utility precisely the increase (or decrease) which has occurred in operating cost.

It should be emphasized that the fuel adjustment clause is not a substitute for a formal rate case. It is only an interim measure to function between rate cases, adjusting for certain cost changes that continually occur in the market place. Thus, it is not a mechanism to preserve the company's allowed rate of return per se (there are other clauses which can be designed for this purpose, i.e., service-at-cost plans), but serves only to mitigate the effect on the rate of return of a certain preselected cost item or items.

Implications of Fuel Adjustment Clauses Related To Utility Commission Control Over Rate Changes

The fuel adjustment clauses are usually considered automatic mechanisms. As the price of fuel varies the utility may vary its own prices according to a predetermined formula. The formula relates the fuel price to the number of kilowatt-hours of output. Thus, when the clause is truly automatic the public agency relinquishes its authority to control price changes by the use of the hearing/review process in favor of a rule. However, during the 1970's many states adopted a monthly hearing/review process to oversee the fuel clause usage. These range from nearly "rubber-stamp" procedures to mini-rate cases that deal only with fuel costs.

Fuel adjustment clauses, as all automatic adjustment mechanisms, are intended to ensure the stability of utility earnings as fuel costs rise and on the downside permit rapid credits to consumers as prices decline. In addition, there is an implied intention to ease the regulatory agency workload based on the assumption that the utility will automatically transfer to the consumer only those cost increases or decreases that cannot be avoided.

Historical Background of FAC's

As was previously noted, fuel adjustment clauses were initially used during World War I because coal prices fluctuated dramatically, principally because of changing labor costs. The primary reason for those fluctuations was the shortage of manpower in the coal mines. In addition, there was another supply shortage, the lack of open hopper rail cars to transport mined coal to the power generating plants. The problem was war-related and became so acute that the rail industry was placed under military control from 1917 to 1920.[2]

By the 1920's the use of operating cost adjustment clauses was a widely accepted method of ratemaking.[3]

Although attempts were made to continue the process, a return to normality led to a declining use of the practice. However, World War II and the post war period with its associated inflationary spiral resulted in renewed usage of automatic adjustments in utility rates. This was possible because public utilities were exempt from the Emergency Price Control Act.[4]

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[2]D.P. Locklin, Economics of Transportation (Chicago, Illinois Business Publications, Inc. 1935), p. 230.

[3]Trigg, op. cit., p. 964.

[4]Paul J. Garfield and Wallace F. Lovejoy, Public Utility Economics (Englewood Cliffs; Prentice Hall Inc., 1975) p. 10.

Jones and Hines note that automatic adjustment clauses have not significantly changed since the year 1947 when Arnold Hirsch reviewed this post World War II issue.[5] Their use has increased, and they have been incorporated by law and practice in most states' regulatory processes. In addition to their use for fuel, automatic adjustment clauses have also been instated for taxes, wages, price level inflation, imbedded debt and environmental costs.[6]

There are several issues arising from the discussion which remain unresolved. For example, when the price of fuel is established as the factor of the fuel adjustment clause, should that price include the cost of transportation, handling or other separate cost components within the calculation methodology?

Common Current Uses of FAC's

To offset the volatile and sustained upward trend in fuel costs since 1973, electric utilities have quickly returned with commission approval to the fuel adjustment clause. In the 1974 Congressional Research Service Survey it was found that:[7]

1. General rate increases and increase due to the fuel adjustment clause totaled $9.6 billion. (This figure was projected from the $6.6 billion reported by the 37 state commissions responding to the survey.)

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5 Arnold Hirsch, "Fuel Clause et al. versus Effective Rate Regulation," Public Power Magazine, March 1947, cited in Douglas N. Jones and Sara Hines Memorandum of the Congressional Research Service to the Government Operations Committee, published in Congressional Record, Volume 120, No. 105, July 16, 1974, p. 12505-12511.

6 Ibid., p. 12506.

7 U. S. Congress, Senate, Subcommittee on Intergovernmental Relations and the Subcommittee on Reports, Accounting and Management of the Committee on Governmental Operations United States Senate, Electric and Gas Utility Rate and Fuel Adjustment Clause Increases, 1974 by Douglas N. Jones and Susan Dovell, Committee Print (Washington, D.C.: Government Printing Office, 1975), p. v-vi. Similar Reports for 1975, 1976 and 1977 were published by the Committee. The 1975 Report was by Douglas N. Jones and Angela Lancaster, those for 1976 and 1977 were by Douglas N. Jones and Russell J. Profovich. This discussion incorporates data relating to the multi-year analysis of several aspects of regulation and the fuel adjustment usage.

2. More than $3 billion in general rate increase requests were pending before the commissions that responded. (Historically, commissions have granted about two-thirds of rate increase requests.)

3. Four-fifths of the increased rates were for electricity, the rest for natural gas.

4. Two-thirds of the increases resulted from higher fuel costs passed through to customers because of fuel adjustment clauses.

5. Changes in rates because of fuel adjustment clauses--$6.5 billion in 1974--were more than four times as large as the increase of $1.3 billion in 1973 because of the same clauses.

Furthermore, 125 additional companies added a clause to their rate schedules during the 1970's; 63 of them in 1974 alone.

By 1977, it was found by a subsequent study that fuel adjustment charges by investor-owned gas and electric utilities have increased to an annual amount of $11.0 billion. That represented an increase of $1.4 billion from the previous year. Total changes from 1973 through 1977 in fuel adjustment revenues alone were $35.6 billion. By comparison rate case increases in 1977 declined from the 1976 reported amount that had in turn declined from the 1975 estimate.

The total amount of change can be observed from the following table:[8]

Table 1-1 Comparison of FAC Revenues And Rate Case Increases In Billions of Dollars

Year	FAC Revenue	Rate Case Increases
1974	$ 6.5	$ 3.1
1975	8.5	4.1
1976	9.6	3.1
1977	11.0	2.4

Source: (8)

[8] Senator Edmund S. Muskie and Senator John Glenn, "Introduction" Electric and Gas Utility Rate and Fuel Adjustment Clause Increases, 1977, by Russell J. Profozich and Douglas N. Jones, Committee Print (Washington, D.C.: Government Printing Office, 1978), p. vii.

Further, it should be pointed out that during the four years covered by the study, increases in fuel costs were actually greater than they appear in the table. Many fuel adjustment charges were incorporated, either in full or partially, into the eventual rate increase. The 1977 Report indicated that two-thirds of the commissions reported that some prior automatic fuel costs had been transferred into the new basic rate structure for electric utilities. About 50 percent reported similar instances of incorporation for gas utilities. These basic rate transfers reflect decreases in the reported proportion of fuel adjustment revenues to total revenues.

The above results plus the detailed findings of the Congressional Research Service led the senatorial sponsors of the study to the following conclusions:

> The survey shows that utilities fared well last year [1977]. The cost-plus regulatory system under which utilities operate provides them with operating and investment revenues plus profit. Fuel adjustment clauses have facilitated the collection of more than $35 billion in revenue in four years. As these fuel charges are rolled into the basic rate structure, the identifiable FAC charge on utility bills decreases, although the total bill often increases.
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> Many utility commissions have permited use of fuel adjustment clauses as an alternative to the more difficult and time-consuming task of considering rate increase requests in formal hearing, where intervenors and commission staff can challenge, question and counter utility proposals. Commissions generally report that FAC's are subject to periodic review. The authors of the Congressional Research Service analysis make the point that "a periodic review is not the same as an evidentiary hearing, and care must be taken to ensure that such reviews do not simply 'rubber-stamp' the information provided by the utility companies."
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> Utilities whose rate increase requests were subject to formal proceedings obtained only half of what they asked for in 1977. It is possible that the $11 billion in revenues obtained through automatic FAC's might have been similarly reduced had it been subjected to evidentiary hearings.

There are some indications that the states are tightening up on escalation of utility bills through use of FAC's. The number of commissions which did not roll any FAC charges into basic rates increased from seven in 1976 to 11 in 1977. Ten commissions--with Arizona making the choice in mid-August, 1978--now partially or totally prohibit use of FAC's. [9](*)

In spite of the criticisms of FAC's, they remain a prevalent feature of ratemaking. At the end of 1978, a fuel adjustment clause was in use in 43 states and the District of Columbia. The states without FAC's were Idaho, Montana, Oregon, Utah, Washington and West Virginia. Nebraska does not regulate electric utilities at the state level, but at least some of the public power districts and municipal utilities use FAC's. In its 1978 Report, the National Association of Regulatory Utility Commissioners stated that there are variations in fuel adjustment clause structure and operation from state to state.[10] The variations result from differences in operating characteristics and the general environment as well as regulatory agency policies and practices. The principal causes of variation relate to the type and nature of costs to be included, the design complexity of the formula used, the factors considered in the adjustment determination and the time lag between cost incurrence and recovery from the consumers.

Effects of FAC's On Rate Making Procedures

As mentioned the principal objective of a fuel adjustment clause is to protect both the utility and the consumer at a time when prices are fluctuating. The FAC reduces the lag in cost recovery by the utility. Thus, the regulatory agency chooses to forego the normal evidentiary procedures applicable to general rate changes in favor of an automatic formula. To the extent that the automatic increases remain unreviewed the public authority may be surrendering a portion of its responsibility.

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[9]Ibid., pp. viii-ix.

(*)Idaho, Montana, Oregon, Nevada, Washington and Utah commissions do not use either electric or gas FAC's. Colorado and Kansas FAC's apply to electricity only. The West Virginia legislature forbade use of FAC's by electric utilities in 1975. Nebraska does not prohibit FAC's; the state does not regulate electric and gas utilities.

[10]Paul Rodgers, Gordon Pozza, David J. Burke, State Commission Regulation and Monitoring of the Fuel Adjustment Clause, Purchased Gas Adjustment Clause, and Electric and Gas Utility Fuel Procurement Practices. National Association of Regulatory Utility Commissioners, Washington, D.C., 1978; pp. 7-40.

In addition to volatility, there is a question of the use of automatic cost adjustments when the costs in question fail to represent a significant portion of the total cost. Public regulators need to continuously review the adjustments to determine whether the volatile nature is combined with a high level of cost significance.

Probably the most serious concern to be considered is the control over costs the utility may exercise. There is a tendency to disregard the control factor in the use of automatic adjustment clauses. Utility companies that own or control their own fuel supply may take unfair advantage of an adjustment clause. The question of the continued or increased use of a costly fuel because costs can be passed through, must also be considered, as must the incentive to choose fuel costs over plant costs where the former are not scrutinized and the latter are.

Three criteria for continued use of fuel adjustment mechanisms are important to be met. They constitute the test of appropriateness. The lack of the existence of any one of the three constitutes a reason to at least question and perhaps disallow automatic power rate increases. The criteria are:

1. Extreme volatility of fuel prices, fluctuating up and down during short time periods.
2. Fuel costs constitute a significant portion of total costs.
3. The cost of fuel involves a cost over which the utility has little or no control.

Concerns Over FAC's

Over the past several years, the energy shortage, continuing inflation, the rising concerns of consumers and environmentalists, and the uncertain future of nuclear power have all combined to force a continuous questioning of the use and design of fuel adjustment clauses (FAC's). While some of the furor over FAC's might be better directed at rising fuel costs than at the clauses themselves, nevertheless, at least three major legitimate concerns about FAC's have been raised.

One concern is primarily legal and centers on the question of due process. Do FAC's allow utilities to avoid the close scrutiny of expenses which characterize a rate case, and if so, is this legal? To a certain extent, this question must be resolved in light of each state's own statutes.

A second concern is that FAC's focus on only one element of cost, and other costs may be moving at a different rate or even in an opposite direction, e.g., taxes. Preoccupation with one cost element may distort the outcome.

A third concern is that FAC's are viewed as part of a trend away from evidentiary rate hearings, to rulemaking, and to regulation by formula. FAC's, it is argued, capture the benefits of such a procedural trend, namely, (1) reduced costs of regulation, (2) reduced regulatory lag, and (3) reduced uncertainty to the regulated utilities. From the standpoint of procedural efficiency, FAC's may be desirable.

There is concern, however, that such a trend may result in economic inefficiencies. FAC's may reduce the incentives of utility management to operate in the most economically efficient manner. In particular, FAC's may influence management judgment concerning, among other issues, (1) the degree of hard bargaining over fuel prices, (2) the energy efficiency of power plants, (3) maintenance schedules, (4) trade-offs between fuel quality and transportation costs, (5) the best way to meet environmental standards and, in the long run, (6) the adoption of alternate generation technologies. Further, the application and operation of FAC's have often resulted in accounting mischief to the detriment of the ratepayer.

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Chapter 2 presents a discussion of the appropriateness of fuel adjustment clauses. Emphasis will be on the arguments for or against the FAC. Those in favor argue that the automatic adjustment meets the revenue requirements of public utilities, reduces interest costs, provides scarcity signals to, or passes fuel savings back to, consumers and reduces the cost of regulation. The arguments in opposition hold that the automatic adjustment mechanism promotes economic inefficiency by encouraging added use of production methods and mixes which should be altered, fails to encourage fuel price bargaining by management, encourages inclusion of improper costs, infringes on the consumer's right of review and adds to confusion because of increased billing complexity.

In Chapter 3 is a summary of the characteristics of the FAC's and associated procedures in the fifty states. Much of the information is from the 1978 NARUC report on FAC practices.[11] The summary covers whether a standard statewide FAC is required, and, if so, how it is designed.

In Chapter 4 alternate approaches for FAC design are discussed. Chapter 5 contains an analysis of options for building into the FAC incentives for economical performance and discusses avoidance of negative incentives for input mix distortion. Chapter 6 concludes with a discussion of monitoring procedures for overseeing FAC operation.

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[11] Rodgers, Pozza and Burke, op. cit..

CHAPTER 2
PROS AND CONS OF FUEL ADJUSTMENT CLAUSES

Before proceeding with a detailed examination of fuel adjustment issues, it should prove helpful to review several of the major arguments, both pro and con, that have appeared in the literature on fuel adjustment clauses. The reader should bear in mind that the specific design of the fuel adjustment mechanism may vary considerably from state to state and that design may substantially influence its suitability. At present let us describe the benefits and problems of fuel adjustment in general.

The Advantages of FAC's

The single most important advantage of fuel adjustment clauses is to protect the utility's earnings during periods of rapidly increasing fuel costs. If a public utility is to remain solvent over time, the total revenue generated from its sales must be large enough to cover its total cost of production. In addition, if a utility is to be able to attract new investment funds it must offer its shareholders a "fair rate of return" on their investment. Ratemaking's twin goals of preventing utility bankruptcy as well as assuring the utility's capacity to attract needed funds is reflected in its revenue requirement. The FAC's currently in use provide a mechanism for assuring that the revenue needs of public utilities will be met.

The early literature on the use of automatic rate adjustments stresses their ability to match the utility's costs and revenues over the business cycle. In a 1958 article in favor of the use of automatic adjustment clauses in utility regulation it was argued,

> One of the major problems in public utility regulation is the reconciliation of fixed rates to the pressures and demands of a fluctuating economy. Failure to make such a reconciliation results in unreasonably high rates in periods of economic recession, and hardship to the utility (in a few cases threatening discontinuance of service) during inflationary cycles. These effects are the twin offspring of the inevitable lag between general price changes and regulatory approval of changes in utility rates. The simplest and most widespread solution of the problem is the use of automatic rate adjustments, whereby the rates are allowed to vary automatically with changes in operating costs, prices of basic raw materials, or independently-published price indices.[1]

Thus, in a period of prosperity characterized by rising fuel prices, a fuel adjustment clause helps to assure that utilities will receive the additional revenue needed to meet the rising fuel costs. During a severe recession any decline in the price of fuel would, if the FAC is functioning properly, cause the fuel savings to be passed along to consumers. Hence, over the course of the business cycle an FAC could in theory protect utilities from rising fuel costs and consumers from excess fuel charges.

Stated another way, FAC's tend to reduce the fluctuation in the earnings of a public utility during a period of inflation. Without a fuel adjustment clause, rising fuel costs could not be offset by higher electricity prices until a rate hearing is held. Hence, in an inflationary period characterized by rising fuel prices, the earnings of a typical public utility without an FAC could deteriorate markedly during the interim between rate hearings. Thus without an FAC, utilities could expect to see their earnings fluctuate over a rate hearing cycle.

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[1] R.S. Trigg, "Escalator Clauses in Public Utility Rate Schedules," 106 University of Pennsylvania Law Review, p. 964 (1958).

Earnings would peak just after each rate case and would decline during the period between rate cases due to rising fuel costs. Obviously the magnitude of the fluctuations in the earnings of utilities depends upon the severity of inflation as well as the length of time between rate cases. The more rapid the rise in resource prices and the longer the time between rate cases, the greater will be the oscillation in utility earnings. A fuel adjustment clause would tend to reduce this periodic fluctuation in utility earnings, since the utility would receive relief at least from rising fuel prices prior to the next rate hearing.

The fact that FAC's tend to reduce the variation in utility earnings over time leads, according to advocates, to another important advantage associated with the use of FAC's: fuel adjustment clauses may reduce the interest expense associated with the money utilities need to raise in order to finance their capital expenditures. Public utilities are characterized by unusually heavy expenditures on plant and equipment. Hence, a typical utility must secure large amounts of funds either on the open market or through the sale of securities. The rate of interest that a utility must pay to bondholders or new stockholders in order to raise additional funds or to refinance old debt depends upon the risk associated with the utility's securities. If the utility is not covered by an FAC which prevents the drastic fluctuation of the utility's earnings over time, then investors may regard this utility's securities as a risky investment requiring a higher interest rate to compensate for this risk. As one industry representative stated the case for FAC's, "If recovery of added fuel costs is delayed, earnings may fluctuate radically; this increases financing costs and possibly delays construction resulting in higher rates than with an automatic fuel adjustment clause."[2] Thus a well designed FAC, it is argued, may in fact be able to lower the cost of electricity to consumers by reducing the interest expense incurred by the utility.

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[2]"An Explanation: Rising Fuel Costs and the Fuel Adjustment Clauses Used by Seven Ohio Electric Utilities," presented for the Ohio Electric Utility Institute and distributed to the Joint Select Committee on Energy, as part of the testimony of Bruce Mansfield, May 8, 1975, p. 4.

The third major advantage associated with the use of FAC's is that FAC rate changes quickly signal customers regarding energy scarcity. The FAC allows the rapidly rising price of increasingly scarce fuel to be quickly passed on to consumers in the form of higher electricity prices. Thus consumers who are in the process of deciding what appliances to purchase can take the higher price of electricity into account when making their decisions rather than being surprised when, after a rate hearing, electricity prices take a sudden jump upward. Hence FAC's may aid energy conservation by providing consumers with a timely warning of increasing fuel scarcity. With an FAC a consumer who is considering the purchase of whole-house air conditioning is apt to be more aware of increasing energy scarcity.

An industry spokesman's argument regarding the advantages offered by FAC's in terms of the incentives they provide for user efficiencies is:

> Under the new peak-load pricing concepts, the price of electricity from time-to-time is to be as nearly equal to the cost of service as possible so that the customer can make a valid economic choice whether or not to use the service. Delaying the application of increased fuel adjustments pending hearings appears contrary to this latest thinking of economists on rate philosophies.[3]

Thus, under this logic, FAC's aid consumers in making economic choices by providing them with timely, up to date information on electricity prices.

The fourth advantage of FAC's is that they can immediately pass along fuel savings to consumers. In particular this is characteristic of fuel adjustment clauses that employ a variable heat rate. A heat rate is simply the number of BTU's needed to generate a kilowatt-hour of electricity. Under a variable heat rate FAC, if fuel becomes less expensive or if the utility becomes more efficient in the use of fuel (i.e., has a lower heat rate), then the fuel savings will be passed along to consumers. Thus consumers are less likely to be overcharged for the fuel used in generating electricity with a variable heat rate FAC in effect.

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[3] Mansfield, _op_. _cit_., p. 8.

Lastly, in theory if not always in practice, FAC's should reduce the cost of regulation. Since FAC's provide for an automatic adjustment of utility rates when fuel prices increase, they act as a substitute for the frequent rate hearings which might otherwise be necessary. Hence, FAC's provide an inexpensive regulation-by-formula alternative to the more costly frequent rate hearing approach. In actuality many states, in response to concern over rising electricity rates, have stepped up their monitoring of the operations of FAC's. In fact, fourteen states now require a hearing before allowing utilities to increase rates under a fuel adjustment clause. Hence we see that FAC's can reduce the cost of regulation but this will not necessarily be the case depending upon the degree of monitoring which each state deems appropriate in administering its FAC.

The Disadvantages Of FAC's

Much of the current criticism directed toward FAC's stems from the sheer unanticipated magnitude of the increases in utility rates associated with the operation of FAC's. In a previously cited report (supra p. 5) some historical perspective on these adjustments was given when it was noted that during at least one recent year alone, consumers paid more than one and a half times as much to cover utility rate increases as they did over the entire previous quarter century.[4] As energy becomes increasingly costly it is understandable that consumers will protest the FAC mechanism by which higher fuel costs are passed along to them.

One major disadvantage of FAC's is that they may distort the input mix. That is, since an FAC covers only fuel cost, this may encourage firms to substitute fuel for other resources such as labor and capital. In a period characterized by a general inflation of resource prices, utilities may well find it advantageous to utilize more intensively

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[4] Electric and Gas Utility Rate and Fuel Adjustment Clause Increases, 1974, prepared for the Subcommittee on Intergovernmental Relations and the Subcommittee on Reports, Accounting and Management of the Committee on Government Operations, U.S. Senate in cooperation with State Utility Commissions by Douglas N. Jones and Susan Dovell, March 27, 1975.

those resources which are covered by an automatic adjustment clause. The resulting distortion of the input mix would cause the cost of producing electricity to be higher than it would otherwise have to be. The degree of input distortion depends upon several factors including the type of heat rate factor used in deriving the FAC. Detailed discussion of input mix distortion is deferred until a later chapter.

Another important criticism of FAC's is that they compensate for managerial inefficiency. Under a rate structure without an FAC, the time lag between rate hearings means that rates will be frozen during this time interval. Hence, managerial failure to suppress costs will be penalized by falling utility earnings. A fuel adjustment clause partially relieves the pressure on utility management to reduce costs, since the FAC provides partial rate increases while the utility's management awaits the next rate case. Thus FAC's may have the unintended effect of partially protecting utility management from the consequences of less than satisfactory performance.

Another closely related criticism of FAC's is that they reduce the incentive for utilities to engage in hard bargaining to assure that the lowest possible price is paid for the needed fuel. A report by the National Association of Regulatory Utility Commissioners (NARUC) states,

> When cost increases can be passed on to the consumer quickly and easily there is a tendency to dampen the company's incentive to seek a lower cost supplier or bargain for a better fuel price or better wage settlement, etc. As a consequence, the clauses may result in avoidable price escalation for the adjustable item.[5]

Thus the utility may care very little when fuel prices increase, if the burden of this price increase can be immediately and completely shifted to consumers.

Another criticism frequently leveled against the use of FAC's is that they sometimes cover improper or inappropriate costs. Since each state using an FAC mechanism determines what costs can be included under the fuel adjustment provisions, there is considerable variation among

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[5] Automatic Adjustment Clauses Revisited, National Association of Regulatory Commissioners, Economic Paper No. 1R by Subcommittee of Staff Experts on Economics, July 8, 1974, pp. 3-4.

the fuel adjustment provisions, and there is considerable variation among the states regarding the types of costs that can be included under the FAC umbrella.

Several other criticisms of FAC's deal with the rights of consumers. For example, a fuel adjustment clause to some extent must infringe upon the consumer's ability to review and challenge the justification of a billing change before that increase goes into operation. Under most of the present FAC's consumer groups can only challenge an FAC rate increase after the fact. Several states have recently instituted FAC hearings prior to FAC-induced rate increases.

Another problem associated with the adoption of an FAC is that it makes the rate structure more complex and less readily understood by consumers. Consumers, under an FAC system, find it difficult to determine if they are being billed properly for the fuel they consume, especially if fuel charges are both in basic rates and FAC's. This naturally increases consumer suspicions regarding the purpose of FAC's.

Lastly, an FAC may allow consumers to be overcharged for fuel costs. This result depends upon the specific design of the FAC because it is possible to employ an FAC design which permits the systematic collection of FAC revenues in excess of actual fuel costs. Such features as a fixed heat rate, for example, could lead to the excessive collection of FAC revenues.

The reader should note that many of the FAC benefits and costs are interrelated. For example, efforts to use profit incentives to encourage utilities to improve managerial efficiency and to use the cost minimizing mix of inputs may lead to an FAC overcharge. Also, attempts to prevent the inclusion of improper costs in an FAC may lead to higher costs of regulation. Ideally, a properly designed FAC would retain all the advantages and eliminate the disadvantages. In practice this is not possible. In times and places that an FAC appears necessary, a practical goal of regulation is to design an FAC and an associated set of regulatory procedures which retain most of the advantages and eliminate most of the disadvantages discussed in this chapter. Such a design is the subject of most of the remainder of this report.

Before taking up the subject of FAC design however, we consider the current usage of fuel clauses in the United States.

CHAPTER 3

FAC USAGE AND CHARACTERISTICS

This chapter contains information on the fuel adjustment clauses for the fifty states, including the existence or absence of a fuel adjustment clause, and whether it is an automatic adjustment clause or if a hearing is required before allowing the utility to increase charges. Also considered is a description of the major items covered by the fuel adjustment clause. Questions specifically dealing with handling of nuclear fuel by the fuel adjustment clause are discussed. Information on the fuel adjustment clause such as the time lag in passing increased fuel costs on to customers and the method of heat rate utilization, are included as well as any legislation since 1970 which has modified or abolished the FAC (as of August 1978). Also, information is given on the extent to which power plant productivity is used as a factor affecting the utilities' ability to recover fuel costs in the fuel adjustment clause. Finally, the review procedures of state public utility commissions in monitoring the operation of fuel adjustment clauses are summarized.

Based on the data reported in Table 3-1 for the 50 states and the District of Columbia, 44 commissions allow a fuel adjustment clause. In 29 states this results in an automatic increase in rates in accordance with a previously designed formula. In 15 states a hearing is required before utilities may increase rates. The states which do not have an FAC include Idaho, Montana, Oregon, Utah, Washington, and West Virginia. Nebraska's electric and gas utilities are not regulated at the state level; some of these utilities have FAC's.

Table 3-1 FAC Existence, Prior Hearing Requirements and Coverage As of 1978 (1)

State	(a) Does an FAC Exist?	(b) Is a Hearing Required Prior to FAC Adjustments?	(c) Major Items Covered by FAC (2)
Alabama	Yes	No	The cost of coal and the purchased power.
Alaska	Yes	No	Fuel costs with the gross receipts tax not included.
Arizona	Yes	Yes	The cost of fuel and purchased power including accounts (501, 518, 536, 547 and 555).
Arkansas	Yes	No	Fossil fuel, purchased power costs and all components of nuclear fuel.
California	Yes	Yes	Direct and indirect costs of fossil fuel. For nuclear fuel all costs in 518 plus if utility owns the fuel a "normal year" level is in base. Includes geothermal energy and purchased power costs. Excludes company-owned transportation and handling charges, operation & maintenance charges.
Colorado	Yes	Yes	Account 501 is used for steam power and account 547 for other power sources. All components of nuclear fuel included. Excluded are all fuel transportation and handling costs as well as ash disposal costs.

(1) The information is based on a NARUC survey, May through August 1978.
(2) Account numbers refer to cost categories as defined by NARUC, FERC or the state commission's uniform system of accounts.

Table 3-1 (continued) FAC Existence, Prior Hearing Requirements and Coverage As of 1978 (1)

State	(a) Does an FAC Exist?	(b) Is a Hearing Required Prior to FAC Adjustments?	(c) Major Items Covered by FAC (2)
Connecticut	Yes	Yes	Accounts 501 and 547 cleared from account 151, plus the net cost of fuel attributable to power purchased or sold. No components of nuclear fuel included.
Delaware	Yes	Yes	Accounts 501 and 547 cleared from account 151; including i) fossil and nuclear fuel costs of net purchased power. ii) net energy costs of purchased power excluding demand charges when power is purchased using an economic dispatch method. iii) Nuclear expenses included in account 518.
D.C.	Yes	No	Accounts 501, 547, and 555 and costs of fuel handling and procurement and ash disposal. Items not covered include fuel acquisition and processing costs and the gross receipts tax.
Florida	Yes	Yes	Accounts 501, 547 and purchased power fuel expense for the four major generating utilities. Fuel-handling costs are not covered but all components of nuclear fuel are included.
Georgia	Yes	No	Accounts 501, 518, 547 and 555. Fuel-handling costs are not covered.

(1) Information is based on a NARUC survey from May through August 1978.

(2) Account numbers refer to cost categories as defined by NARUC, FERC, or the state commission's uniform system of accounts.

Table 3-1 (continued) FAC Existence, Prior Hearing Requirements and Coverage As of 1978 (1), (3)

State	(a) Does an FAC Exist?	(b) Is a Hearing Required Prior to FAC Adjustments?	(c) Major Items Covered by FAC (2)
Hawaii	Yes	No	Fuel costs.
Idaho	No	—	—
Illinois	Yes	No	Fuel costs, the gross revenue tax, ad valomen tax on large-use rates, nuclear fuel expense and purchased power are included. Costs covered vary by company.
Indiana	Yes	Yes	Fossil fuel in account 151 and 518 for nuclear fuel plus: fuel costs associated with purchased power less: fuel costs recovered through intersystem sales. Fuel-handling costs are not covered.
Iowa	Yes	No	Accounts 501 and 547 cleared from account 151 and nuclear fuel in account 518 plus: i) cost of steam purchased from other utilities less expenses for steam sold to others. ii) cost of water for hydro-electric power in account 536. iii) cost of energy purchased less revenues from sales to other utilities. Fuel-handling costs and waste disposal costs are not covered.
Kansas	Yes	No	Fossil fuel cost in account 518 and purchased power in account 555.

(1) The information is based on a NARUC survey from May through August 1978.

(2) Account numbers refer to cost categories as defined by NARUC, FERC or the state commission's uniform system of accounts.

(3) A dash (—) in the table indicates that the question does not apply to a particular state.

Table 3-1 (continued) FAC Existence, Prior Hearing Requirements and Coverage As of 1978 (1)

State	(a) Does an FAC Exist?	(b) Is a Hearing Required Prior to FAC Adjustments?	(c) Major Items Covered by FAC (2)
Kentucky	Yes	No	Cost of fuel used excluding fuel handling. Includes net cost of purchased power with the exception of demand or capacity charges.
Louisiana	Yes	No	Account 151 plus i) net cost of purchased power excluding the cost of power sold to other jurisdictional systems.
Maine	Yes	Yes	Fuel cost and fuel portion of purchased power.
Maryland	Yes	Yes	Account 151 for fossil fuel or account 518 for nuclear fuel. Purchased power fuel costs are covered.
Massachusetts	Yes	Yes	Fuel cost and purchased power costs. The gross receipts tax is excluded.
Michigan	Yes	No	Cost of fuel, transportation costs and interchanged power. Fuel-handling and testing costs and the gross receipts tax are not covered. All components of nuclear fuel included.
Minnesota	Yes	No	Fossil fuel in account 151 and 518 for nuclear fuel and purchased power in account 555. All components of nuclear fuel included.
Mississippi	Yes	No	Fuel costs excluding the gross receipts tax and nuclear fuel costs.

(1) The information is based on a NARUC survey from May through August 1978.

(2) Account numbers refer to cost categories as defined by NARUC, FERC or the state commission's uniform system of accounts.

Table 3-1 (continued) FAC Existence, Prior Hearing Requirements and Coverage As of 1978 (1), (3)

State	(a) Does an FAC Exist?	(b) Is a Hearing Required Prior to FAC Adjustments?	(c) Major Items Covered by FAC (2)
Missouri	Yes	No	Coal costs and 85% of purchased power. The cost of purchased power generated with oil is not covered.
Montana	No	—	—
Nebraska	No, (4)	—	—
Nevada	Yes	Yes	Accounts 501, 547, and 555 utilized.
New Hampshire	Yes	Yes	Cost of fossil fuel and purchased power. Nuclear fuel costs are not covered.
New Jersey	Yes	Yes	Fuel cost, transportation, purchased power, revenue taxes and energy loss.
New Mexico	Yes	No	Allows pass through of all increased costs. Fuels covered are: accounts 151, nuclear fuel, 555, and 447.
New York	Yes	No	Fossil fuel, purchased power and nuclear fuel amortization. Coal storage expense is not covered.
North Carolina	Yes	Yes	Fuel costs in account 151 for fossil fuel, 518 for nuclear fuel, net purchased power fuel costs, and interchange power fuel costs. Coverage does not include nuclear fuel disposal, leased fuel rental and disposal costs and fuel analysis.

(1) The information is based on a NARUC survey from May through August 1978.

(2) Account numbers refer to cost categories as defined by NARUC, FERC or the state commission's uniform system of accounts.

(3) A dash (—) in the table indicates that the question does not apply to a particular state.

(4) The State of Nebraska does not regulate electric utilities

Table 3-1 (continued) FAC Existence, Prior Hearing Requirements and Coverage As of 1978 (1), (3)

State	(a) Does an FAC Exist?	(b) Is a Hearing Required Prior to FAC Adjustments?	(c) Major Items Covered by FAC (2)
North Dakota	Yes	No	Cost of fossil and nuclear fuel and the fuel costs of net purchased power. Coal-handling costs are not covered.
Ohio	Yes	No	Cost of fuel (account 501, 547 cleared from 151) plus: net purchased power costs. The gross receipts tax, line losses and fuel handling are not covered.
Oklahoma	Yes	No	Accounts 501 and 555 related to fossil fuel and purchased power. Fuel handling is not covered.
Oregon	No	—	—
Pensylvania	Yes	No	Fossil fuel in accounts 501 and 547 and: i) nuclear fuel in 518 and 521 ii) net energy purchased and interchanged on account 555. The salvage value of nuclear fuel, fuel-handling costs, waste disposal costs and demand charges on net purchased power are not covered.
Rhode Island	Yes	No	Fuel costs and all transportation costs including company owned non-capital transportation costs. Also the fuel cost of purchased power is covered.

(1) The information is based on a NARUC survey from May through August 1978.

(2) Account numbers refer to cost categories as defined by NARUC, FERC or the state commission's uniform system of accounts.

(3) A dash (—) in the table indicates that the question does not apply to a particular state.

Table 3-1 (continued) FAC Existence, Prior Hearing Requirements and Coverage As of 1978 (1), (3)

State	(a) Does an FAC Exist?	(b) Is a Hearing Required Prior to FAC Adjustments?	(c) Major Items Covered by FAC (2)
South Carolina	Yes	No	Accounts 151 for fossil and 518 for nuclear fuel plus net purchased power fuel costs.
South Dakota	Yes	No	Cost of fuel and purchased power fuel costs.
Tennessee	Yes-for one utility	No	The utility does not generate power so the FAC covers purchased power only.
Texas	Yes	No	Fossil and nuclear fuel costs plus net purchased power costs. Fuel transport costs after delivery of fuel and line losses are not covered.
Utah	No	—	—
Vermont	Yes	No	Accounts 501, 547, and purchased power costs. Nuclear power costs vary from company to company.
Virginia	Yes	No	Fossil fuel in accounts 501 and 547 cleared from account 151. Nuclear fuel in 518. The energy costs of net energy purchases are covered. Demand charges on purchased power are excluded under an economic dispatch.
Washington	No	—	—
West Virginia	No	—	—

(1) The information is based on a NARUC survey from May through August 1978.

(2) Account numbers refer to cost categories as defined by NARUC, FERC or the state commission's uniform system of accounts.

(3) A dash (—) in the table indicates that the question does not apply to a particular state.

Table 3-1 (continued) FAC Existence, Prior Hearing Requirements and Coverage As of 1978 (1)

State	(a) Does an FAC Exist?	(b) Is a Hearing Required Prior to FAC Adjustments?	(c) Major Items Covered by FAC (2)
Wisconsin	Yes	No	Accounts 501, 518, 547, 536 and 555. Covering fossil and nuclear fuel, purchased power etc.
Wyoming	Yes	Yes	Fossil fuel and purchased power costs.

Source: P. Rodgers, G. Profyz and D. Burke, State Commission Regulation and Monitoring of the Fuel Adjustment Clause, Purchase Gas Adjustment Clause, and Electric and Gas Utility Fuel Procurement Practices. NARUC (Washington, D.C. 1978). Columns (a) and (b) from I-A, pp. 178-183. Column (c) from table I-B, pp. 184-194.

(1) The information is based on a NARUC survey from May through August 1978.

(2) Account numbers refer to cost categories as defined by NARUC, FERC or the state commission's uniform system of accounts.

As indicated by Table 3-1, the major items covered by the FAC vary considerably from state to state. The cost of fuel is the most important item in the FAC. Most states permit purchased power to be covered by the FAC with the provision that the cost of power sold is to be subtracted from the adjustment. Other items commonly excluded from the FAC are the fuel-handling cost and the gross receipts tax.

Because of the unique nature of nuclear fuel, it often receives special consideration when included in the FAC. There are two major areas in which nuclear fuel costs differ from fossil fuel costs. The first of these deals with the timing of payments for the fuel. A utility ordering nuclear fuel may order enough fuel for a full year's operation, but fossil fuel is ordered on a monthly basis. Often, the utility has a sizable investment in nuclear fuel before it is used. These large investments can create cash flow problems for utilities forcing them to seek some means of financing this investment. This leads to the second major difference between fossil fuel and nuclear fuel, that of leasing fuel. In contrast to fossil fuel, nuclear fuel may not be owned by the utility that uses it.

Table 3-2 indicates that the leasing of nuclear fuel occurs in 64% of all states (whose utilities use nuclear power). Relevant questions are whether the utilities lease nuclear fuel and whether nuclear fuel costs are calculated each month. Table 3-2 examines how the salvage value of nuclear fuel is treated. This information, combined with the data given on which components of nuclear fuel costs are covered by the FAC, can yield insight into the ways in which nuclear fuel can be handled by the FAC. Although data are scarce, this information from some states should give a general idea of current nuclear FAC practices.

Table 3-3 presents several factors of importance. One item of great importance is the length of the time lag during which an increase in the cost of fuel to the utility cannot be passed on to the consumer in the form of higher rates. Ideally, if the utility cannot affect the cost of fuel, there should be no time lag. However, some time may be needed to determine if proposed rate increases are cost justified. For most states the time lag is less than three months as shown in Table 3-3.

Table 3-2 Nuclear Fuel Cost Procedures As of Mid-1976 (1)

State	(a) Do Utilities Lease Nuclear Fuel?	(b) How is the Salvage Of Nuclear Fuel Handled?	(c) Are Nuclear Fuel Costs Calculated Each Month?
Alabama	—	—	—
Alaska	—	—	—
Arizona	—	—	—
Arkansas	One leases 100% no others with NUC.	A positive value is assigned.	Yes--based on prime rate administrative fee and fuel used.
California	No--2 utilities looking at leasing via subsidiaries.	In accordance with 518	Yes
Colorado	Yes	Taken into account in lease agreement.	Yes
Connecticut	No	(No components of nuclear fuel in FAC)	
Delaware	—	—	—
D. C.	—	—	—
Florida	Yes	By lease	Yes
Georgia	—	—	—
Hawaii	—	—	—
Idaho	—	—	—
Illinois	(Nuclear fuel excluded from FAC)		
Indiana	—	—	—
Iowa	—	Utilities assume no salvage value.	Yes-based on burn up.

(1) A dash (—) in the table indicates that the state did not have nuclear power at the time of the Kurth, Kelly, and O'Hare Survey.

Table 3-2 (continued) Nuclear Fuel Cost Procedures As of Mid-1976 (1)

State	(a) Do Utilities Lease Nuclear Fuel?	(b) How is the Salvage Of Nuclear Fuel Handled?	(c) Are Nuclear Fuel Costs Calculated Each Month?
Kansas	—	—	—
Kentucky	—	—	—
Louisiana	—	—	—
Maine	No	Added to FAC as a credit.	Yes, based on burn up vs. value.
Maryland	Yes - 100%	—	Yes
Massachusetts	—	—	—
Michigan	Yes	Worked into the organization.	Yes
Minnesota	No	Reduction in nuclear fuel expense.	Yes
Mississippi	(FAC excludes nuclear fuel)		
Missouri	—	—	—
Montana	—	—	—
Nebraska	—	—	—
Nevada	—	—	—
New Hampshire	(FAC excludes nuclear fuel)		
New Jersey	—	—	—
New Mexico	—	—	—
New York	(FAC includes nuclear fuel amortization)		
North Carolina	Yes	—	—
North Dakota	(Nuclear fuel included in FAC)		
Ohio	—	—	—
Oklahoma	—	—	—
Oregon	—	—	—

(1) A dash (—) in the table indicates that the state did not have nuclear power at the time of the Kurth, Kelly, and O'Hare Survey.

Table 3-2 (continued) Nuclear Fuel Cost Procedures As of Mid-1976 (1)

State	(a) Do Utilities Lease Nuclear Fuel?	(b) How is the Salvage Of Nuclear Fuel Handled?	(c) Are Nuclear Fuel Costs Calculated Each Month?
Pennsylvania	—	A positive value is assigned.	—
Rhode Island	—	—	—
South Carolina	—	—	—
South Dakota	—	—	—
Tennessee	(All power is purchased)		—
Texas	(FAC includes nuclear fuel consumed)		—
Utah	—	—	—
Vermont	No	Plutonium credit in fuel costs	Yes
Virginia	Yes	Will be entered as cost into new fuel	Yes
Washington	—	—	—
West Virginia	—	—	—
Wisconsin	—	—	—
Wyoming	—	—	—

Sources: Kurth, K. Kelly and T.A. O'Hara, The Inclusion of Nulcear Power in a Fuel Adjustment Clause: Policy Development Project. Department of Mechanical and Nuclear Engineering: OSU (Columbus, Ohio, 1976). Column (a) is from Table B-1, p. 118. Column (b) and (c) are from Table B-2, pp. 119-121.

P. Rodgers, G. Porfya and D. Burke, State Commission Regulation and Monitoring of the Fuel Adjustment Clause, Purchased Gas Adjustment Clause, and Electric and Gas Utility Fuel Procurement Practices. NARUC (Washington, D.C. 1978). All comments in parentheses are from Table I-B, pp. 184 to 194.

(1) A dash (—) in the table indicates that the state did not have nuclear power at the time of the Kurth, Kelly and O'Hare Survey.

Table 3-3 Institutional Aspects of FAC Application as of Mid-1978 (1)

State	(a) Time Lag in Passing Fuel Costs on to Customers	(b) Method of Heat Rate Utilization	(c) Legislation Affecting FAC Since 1970 (2)
Alabama	1 month	Variable	None
Alaska	None	Variable	None
Arizona	None	Variable	None
Arkansas	1-3 months	Variable	None
California	1-2 months	Variable	None
Colorado	1 month	Fixed	None
Connecticut	2 months	Variable	There has been legislation which established guidelines for the Commission regulating the FAC.
Delaware	2 months	Fixed	Legislation requiring hearings before any rate changes have been enacted since 1970.
D.C.	None	Variable	None
Florida	2 months	Variable	None
Georgia	1 month for 1 utility 3 months for 1 utility	Variable	None
Hawaii	None	Fixed	None
Idaho	—	—	—
Illinois	1-3 months	Fixed or variable depending on the company	None

(1) A dash (—) in the table means that information was not available or the question did not apply to the state.

(2) As of May 1978, except for more recent data on Missouri.

Table 3-3 (continued) Institutional Aspects of FAC Application as of Mid-1978 (1)

State	(a) Time Lag in Passing Fuel Costs on to Customers	(b) Method of Heat Rate Utilization	(c) Legislation Affecting FAC Since 1970 (2)
Indiana	None: based on fuel cost projections reconcilia-tion occurs 5 months after expenses.	Variable	On April 30, 1978, Public Law No. 75 became effective which required a hearing before, FAC fuel cost changes.
Iowa	1-2 months	Variable	—
Kansas	None	Limit	—
Kentucky	Varies according to billing method	Variable	—
Louisiana	1-3 months	Variable	—
Maine	1 month	Variable	—
Maryland	2 months	Variable	Partial description of legislative action is: i) provides four com-panies may apply to adjust rates when cost of fuel is 5% different from the cost of fuel in authorized rates. ii) required hearing and findings before ad-justing rates. iii) permits automatic adjustment subject to Commission's approval.

(1) A dash (—) in the table means that information was not available or the question did not apply to the state.

(2) As of May 1978, except for more recent data on Missouri.

Table 3-3 (continued) Institutional Aspects of FAC Application as of Mid-1978 (1)

State	(a) Time Lag in Passing Fuel Costs on to Customers	(b) Method of Heat Rate Utilization	(c) Legislation Affecting FAC Since 1970 (2)
Massachusetts	3 months	Variable	Legislation became effective in 1974 separating all fuel and purchased power costs and requiring a hearing.
Michigan	3 months(3)	Variable	In 1972 legislation became effective which eliminated the statutory prohibition of FAC for residential electricity.
Minnesota	3 months	Variable	None
Mississippi	2 months	Variable	There has been legislation but no details were given.
Missouri	2 months	Variable	In June 1979 the Missouri Supreme Court prohibited FAC's on retail electricity, the matter is currently under appeal.
Montana	—	—	—
Nebraska	—	—	—
Nevada	6-9 months	Variable	None
New Hampshire	2 months	Variable	In 1976 legislation requiring hearings for FAC each month become effective.
New Jersey	None	Variable	None
New Mexico	2 months	Variable	None
New York	1 month	Variable	None

(1) A dash (—) in the table means that information was not available or the question did not apply to the state.

(2) As of May 1978, except for more recent data on Missouri.

(3) Permits by law recovery of only 90% of additional fuel costs.

Table 3-3 (continued) Institutional Aspects of FAC Application as of Mid-1978 (1)

State	(a) Time Lag in Passing Fuel Costs on to Customers	(b) Method of Heat Rate Utilization	(c) Legislation Affecting FAC Since 1970 (2)
North Carolina	3 months	Variable	1975 legislation replaced the FAC with a rate case procedure based on fuel cost.
North Dakota	4 months	Variable	None
Ohio	1-1.5 months	If company falls below target kWh/ MMBTU: FAC formula fixed at value of target.	1975 legislation govern review of FAC and fuel procurement.
Oklahoma	1 month	Variable	Concerning utilities and co-ops 1977 legislation defined terms, provided for approval and of administration certain adjustment clauses, required filings and disclosures; authorized hearings and investigations.
Oregon	—	—	—
Pennsylvania	1-3 months	Variable	1976 legislation became effective which revised price act concerned with regulation including FAC provisions.
Rhode Island	1-2 months	Variable	None
South Carolina	1 month for 1 utility 2 months for 2 utilities	Variable	None

(1) A dash (—) in the table means that information was not available or the question did not apply to the state.

(2) As of May 1978, except for more recent data on Missouri.

Table 3-3 (continued) Institutional Aspects of FAC Application as of Mid-1978 (1)

State	(a) Time Lag in Passing Fuel Costs on to Customers	(b) Method of Heat Rate Utilization	(c) Legislation Affecting FAC Since 1970 (2)
South Dakota	2 months(3)	Variable	None
Tennessee	—	— (4)	None
Texas	None 3 months	Variable	None
Utah	—	—	—
Vermont	3-9 months	Fixed	None
Virginia	Average of 3-5 months	Variable	Amended law concerning fuel cost recovery. Utilities present a forecast to the Commission which allows recovery based on estimates. Recovery is reviewed quarterly.
Washington	—	—	—
West Virginia	—	—	—
Wisconsin	2 months	Fixed	None
Wyoming	None	Variable	None

Source: P. Rodgers, G. Profya and D. Burke, <u>State Commission Regulation and Monitoring of the Fuel Adjustment Clause, Purchased Gas Adjustment Clause, and Electric and Gas Utility Fuel Procurement Practices</u>. NARUC (Washington, D.C. 1978). Columns (a) and (b) are from Table I-B pp. 184-195. Column (c) is from Table 3-B, pp. 248-252.

(1) A dash (—) in the table means that information was not available or the question did not apply to the state.

(2) As of May 1978, except for more recent data on Missouri.

(3) Permits by law recovery of only 90% of additional fuel costs.

(4) Tennessee regulated utilities purchase all power and thus its FAC does not utilize a heat rate calculation.

Another important factor affecting the FAC is the method of heat rate utilization. There are four general forms which the method of heat rate utilization can assume: a fixed heat rate, a variable heat rate, a limit heat rate, and a target heat rate. A fixed heat rate means that the heat rate translator is determined at a rate proceeding and held fixed until the next rate proceeding. A variable heat rate translator can vary over time, while a limit heat rate translator can vary with a certain prescribed upper limit. A target heat rate sets a target level of thermal efficiency. A utility is then penalized if it fails to achieve this level of performance. Only Ohio currently uses a target heat rate. Five states utilize a fixed heat rate translator in their fuel adjustment clauses. These states are Colorado, Delaware, Hawaii, Vermont, and Wisconsin. Of the 43 states and the District of Columbia that have some type of FAC, 34 states and the District of Columbia use a variable heat rate translator. The State of Illinois employs either a fixed or a variable heat rate translator depending on the company being regulated. Kansas is the only state which uses a limit heat rate translator. Most regulated utilities in the State of Tennessee use only purchased power and hence the FAC does not utilize a heat rate translator.

The most common legislation that has occurred since 1970 has been that which requires hearings before allowing utilities to increase rates as a result of fuel cost increases. At least six states have authorized such hearings since 1970 as indicated in the last column of Table 3-3.

In 1978 the staff of the National Regulatory Research Institute visited most states with a survey in which one question, asked of the state commissions, was the extent to which power plant productivity has been used as a factor affecting the utility's ability to recover fuel costs in the FAC. Also asked was what measures were used in evaluating power plant productivity. The answers to these questions are summarized in Table 3-4. Of the 37 states questioned, 16 reported the use of some form of power plant performance incentive.

Table 3-5 indicates the frequency with which state commissions examine the operation of the fuel adjustment clause in their states. Monitoring of fuel adjustments in many states includes a check of FAC computations for accuracy, an audit of fuel procurement, spot checks at generating plants, and public FAC hearings. The audit of fuel procurement can vary dramatically from state to state in its coverage. In some states only fuel costs are audited while many states delve into transportation costs, inventory methods, purchase contracts, and lab reports on fuel. As indicated by the information provided in Table 3-5, most states with FAC's attempt to monitor the implementation of their FAC's rather closely. Of the 43 states and the District of Columbia which have a fuel adjustment clause, 38 check the accuracy of FAC computations monthly. Ten states and the District of Columbia go so far as to audit fuel costs on a monthly basis. Ten states perform spot checks on generating facilities at least once a year, and many other states use spot checks "as needed" or for rate cases. Twenty-one states hold fuel cost or FAC hearings at least once a year. The data seem to indicate that many states rely extensively on "watchdog" procedures for monitoring the operation of FAC clauses.

Table 3-4 The Use of Power Plant Performance (PPP) In Allowing The Recovery Of FAC Covered Fuel Costs as of Autumn 1978 (a)

State	Power Plant Performance Incentives (1)
Alabama	Power plant performance incentive mentioned in rate hearings but never formally studied.
Alaska	No power plant performance incentive feature.
Arizona	No PPP incentive feature.
Arkansas	Monitor PPP measures usually in the course of a rate case. Have not developed specific plan to deal with PPP incentive features but they are being considered.
California	Use PPP as a factor since the dollar value associated with fuel cost increase for inefficient operation. Use AF, CF, FOR and heat rate efficiency as PPP incentive features (see footnote 2 for definitions).
Colorado	Not used or considered as a factor.
Connecticut	Not used or considered as a factor.
Delaware	PPP is a factor which uses generation mix, scheduled and forced outages, cost of fuel and line loss as PPP performance measures along with AF, CF and FOR. (See footnote 2 for definitions.)
D. C.	Use heat rate and load factor as PPP measures. Power plants are located in neighboring states so the use of PPP is stifled.

(1) A dash (—) in the table indicates no response to the survey or the state was not included in the survey (e.g., Hawaii).

(2) AF is the Availability Factor; AF = AH/PH.
CF is the Capacity Factor; CF = MWH/(MW x PH)
FOR is the Forced Outage Rate; FOR = FOH/(SH + FOH)
Where
AH - Total available hours that the plant could generate during the period
PH - Total hours in the period
MWH - Total megawatt hours that were generated during the period by the plant
MW - Megawatt capacity of plant
FOH - Total number of hours that the plant was not available due to a forced outage
SH - Total number of hours that the plant was actually operated.

Table 3-4 (continued) The Use of Power Plant Performance (PPP) In Allowing The Recovery Of FAC Covered Fuel Costs as of Autumn 1978

State	Power Plant Performance Incentives (a) (1)
Florida	Use PPP heat rate component as fuel cost factor. PPP measures are AF, CF and FOR. (See footnote 2 for definitions.)
Georgia	Not used or considered as a factor. AF, CF, FOR used little in considering PPP. (See footnote 2 for definitions.)
Hawaii	—
Idaho	—
Illinois	—
Indiana	—
Iowa	PPP used to assure economic dispatch. Use AF, CF, FOR and scheduled outage as measures. (See footnote 2 for definitions.)
Kansas	If actual performance fall below predescribed levels, then calculations made using limit heat rate values rather than actual values.
Kentucky	Use PPP as a factor using the following measures: a) forced outage provision - limited recovery of costs b) demurrage c) no pass through of coal handling at plant.
Louisiana	Not a factor
Maine	Used as a factor but no details on PPP measures or methods.

(1) A dash (—) in the table indicates no response to the survey or the state was not included in the survey (e.g., Hawaii).

(2) AF is the Availability Factor; AF = AH/PH.
CF is the Capacity Factor; CF = MWH/(MW x PH)
FOR is the Forced Outage Rate; FOR = FOH/(SH + FOH)
Where
AH - Total available hours that the plant could generate during the period
PH - Total hours in the period
MWH - Total megawatt hours that were generated during the period by the plant
MW - Megawatt capacity of plant
FOH - Total number of hours that the plant was not available due to a forced outage
SH - Total number of hours that the plant was actually operated.

Table 3-4 (continued) The Use of Power Plant Performance (PPP) In Allowing The Recovery Of FAC Covered Fuel Costs as of Autumn 1978 (a)

State	Power Plant Performance Incentives (1)
Maryland	—
Massachusetts	Recently used as a factor but no details given.
Michigan	—
Minnesota	Not a factor
Mississippi	Will be considered as a factor when electronic data processing becomes available.
Missouri	Not a factor
Montana	—
Nebraska	—
Nevada	—
New Hampshire	Not a factor
New Jersey	Not a factor
New Mexico	Not a factor
New York	—
North Carolina	Considered as a factor in setting guidelines for minimum standard performance. CF used for nuclear plants as a measure. Other measures used are AF and FOR. (See footnote 2 for definitions.)

(1) A dash (—) in the table indicates no response to the survey or the state was not included in the survey (e.g., Hawaii).

(2) AF is the Availability Factor; AF = AH/PH
CF is the Capacity Factor; CF = MWH/MW x PH)
FOR is the Forced Outage Rate; FOR = FOH/(SH + FOH)
Where
- AH - Total available hours that the plant could generate during the period
- PH - Total hours in the period
- MWH - Total megawatt hours that were generated during the period by the plant
- MW - Megawatt capacity of plant
- FOH - Total number of hours that the plant was not available due to a forced outage
- SH - Total number of hours that the plant was actually operated.

Table 3-4 (continued) The Use Of Power Plant Performance (PPP) In Allowing The Recovery Of FAC Covered Fuel Costs as of Autumn 1978 (a)

State	Power Plant Performance Incentives (1)
Virginia	Has minimal use of PPP as a factor, using AF, CF, and FOR in helping to form opinion. (See footnote 2 for definitions.)
Washington	—
West Virginia	—
Wisconsin	—
Wyoming	—

Source: National Regulatory Research Staff Survey, Autumn, 1978.

(1) A dash (—) in the table indicates no response to the survey or the state was not included in the survey (e.g., Hawaii).

(2) AF is the Availability Factor; AF = AH/PH
CF is the Capacity Factor; CF = MWH/(MW x PH)
FOR is the Forced Outage Rate; FOR = FOH/(SH + FOH)
Where
AF - Total available hours that the plant could generate during the period
PH - Total hours in the period
MWH - Total megawatt hours that were generated during the period by the plant
MW - Megawatt capacity of plant
FOH - Total number of hours that the plant was not available due to a forced outage
SH - Total number of hours that the plant was actually operated.

Table 3-5 Monitoring Procedures Used by State Commissions in Administering Fuel Adjustment Clauses (1)

State	(a) Check of FAC Computations	(b) Audit of Fuel Procurement	(c) Spot Check Of Operating Facilities	(d) FAC of Fuel Cost Hearing
Alabama	Monthly	Monthly	One plant monthly	Monthly
Alaska	Quarterly	Quarterly	Quarterly	None
Arizona	Monthly	None	Monthly	None
Arkansas	Monthly	For rate hearings	When needed	When needed
California	Semiannually	Semiannually	Semiannually	Semiannually
Colorado	Monthly	When needed; with fuel costs audited quarterly	None	Quarterly
Connecticut	Monthly	When needed	For rate hearings	Quarterly
Delaware	Monthly	Monthly	When needed	Monthly
D.C.	Monthly	When needed; with fuel costs audited monthly	When needed	When needed
Florida	Monthly	Monthly	When needed	Monthly

(1) A dash (—) indicates that either the information was not available or the question did not apply to the particular state.

Table 3-5 (continued) Monitoring Procedures Used by State Commissions in Administering Fuel Adjustment Clauses (1)

State	(a) Check of FAC Computations	(b) Audit of Fuel Procurement	(c) Spot Check Of Operating Facilities	(d) FAC of Fuel Cost Hearing
Georgia	Monthly	Monthly	Monthly	None
Hawaii	When fuel costs vary	For rate hearings	When fuel costs vary	None
Idaho	No FAC	For rate hearings	—	—
Illinois	Monthly	For rate hearings	For rate hearings	With rate hearings
Indiana	Monthly	When needed; with fuel costs audited monthly	When needed	Monthly
Iowa	Monthly	For rate hearings	For rate hearings	None
Kansas	Quarterly	For rate hearings; also an annual spot check of fuel costs	Annually	With rate hearings
Kentucky	Monthly	Monthly (only fuel costs)	None	Semiannually
Louisiana	Monthly	When needed; with fuel costs audited monthly	None	Monthly
Maine	Monthly	When needed	When needed	When needed

(1) A dash (—) indicates that either the information was not available or the question did not apply to the particular state.

Table 3-5 (continued) Monitoring Procedures Used by State Commissions in Administering Fuel Adjustment Clauses (1)

State	(a) Check of FAC Computations	(b) Audit of Fuel Procurement	(c) Spot Check Of Operating Facilities	(d) FAC of Fuel Cost Hearing
Maryland	Monthly	Annually; with fuel costs audited monthly	None	Semiannually
Massachusetts	Monthly	Monthly (only fuel costs)	None	Monthly (2) Quarterly Annually
Michigan	Monthly	Annually or semi-annually (2)	Periodically	Semiannually
Minnesota	Monthly	For rate hearings	None	None
Mississippi	Monthly	Monthly (fuel costs only)	None	None
Missouri	Monthly	Annually	None	None
Montana	No FAC	—	—	—
Nebraska	No FAC	—	—	—
Nevada	Semiannually	Semiannually	Semiannually	Semiannually
New Hampshire	Monthly	When needed	As needed	Monthly
New Jersey	Monthly	Annually	Annually	When needed

(1) A dash (—) indicates that either the information was not available or the question did not apply to the particular state.

(2) The frequency of review depends on the particular company involved.

Table 3-5 (continued) Monitoring Procedures Used by State Commissions in Administering Fuel Adjustment Clauses (1)

State	(a) Check of FAC Computations	(b) Audit of Fuel Procurement	(c) Spot Check Of Operating Facilities	(d) FAC of Fuel Cost Hearing
New Mexico	Monthly	For rate hearings (fuel costs only)	None	None
New York	Monthly	When needed; with fuel costs audited annually	When needed	When needed
North Carolina	Monthly	Annually; with fuel costs audited monthly	Monthly	Monthly
North Dakota	Monthly	For rate hearings	None	None
Ohio	Monthly	Annually	When needed	Semiannually
Oklahoma	Monthly	Semiannually	None	Semiannually
Oregon	No FAC	Periodically using a test month	—	—
Pennsylvania	Monthly	Annually	Annually	Annually
Rhode Island	Monthly	For rate hearings	None	Quarterly
South Carolina	Monthly	Semiannually	Semiannually	Semiannually
South Dakota	Monthly	For rate hearings (fuel costs only)	None	None

(1) A dash (—) indicates that either the information was not available or the question did not apply to the particular state.

Table 3-5 (continued) Monitoring Procedures Used by State Commissions in Administering Fuel Adjustment Clauses (1)

State	(a) Check of FAC Computations	(b) Audit of Fuel Procurement	(c) Spot Check Of Operating Facilities	(d) FAC of Fuel Cost Hearing
Tennessee (3)	Monthly	N.A.	N.A.	N.A.
Texas	Monthly	For rate hearings	For rate hearings	For rate hearings
Utah	No FAC	For rate hearings	—	—
Vermont	Monthly	Annually (fuel costs only)	None	None
Virginia	Monthly	Quarterly	Quarterly	Quarterly
Washington	No FAC	—	—	—
West Virginia	No FAC	For rate hearings	—	—
Wisconsin	Monthly	When needed	When needed	When needed
Wyoming	When needed	For rate hearings	None	When needed

Source: P. Rodgers, G. Profya and D. Burke, *State Commission Regulation and Monitoring of the Fuel Adjustment Clause, and Electric and Gas Utility Fuel Procurement Practices*. NARUC (Washington, D.C. 1978). Columns (a) and (b) and (c) are from Table II-B, pp. 202-205 and (b) contains material from Table 2-B, pp. 230-233. Column (d) is from Table II-A, pp. 199-201 and Table II-B, pp. 202-205.

(1) A dash (—) indicates that either the information was not available or the question did not apply to the particular state.

(3) Most regulated electric utilities in Tennessee purchase all their power.

CHAPTER 4
CONSIDERATIONS FOR FAC DESIGN

If a fuel adjustment clause is to be approved by a state utility regulation agency, it is important to design the FAC and an associated set of monitoring procedures which retain most of the advantages and eliminate most of the disadvantages discussed earlier.

Most of the arguments in favor of the FAC implicitly assume that fuel costs are outside of utility control and that increases in these costs are unavoidable by the utility. Unavoidable cost increases must ultimately, one way or another, be borne by the consumer. Without the FAC, additional and avoidable costs may be incurred: increased regulatory costs and capital costs.

Most of the arguments against the FAC assume that increases in cost, including fuel costs, can be controlled by the utility and hence to a certain degree are avoidable by the utility. These include avoidable improper charges, costs avoidable through effective negotiation with fuel suppliers, and costs avoidable through efficient use of productive inputs.

Avoidable and Unavoidable Cost Increases

When the cost of a production factor, such as fuel, rises despite the utility's most efficient efforts, then the firm should be permitted to recover the cost from the consumer. This is an unavoidable cost increase.

In a competitive market situation, the firm must consider price changes on the basis of change in the unit costs of production inputs. So long as the firm can find substitutes for certain production inputs it can control input costs. A common occurrence is to substitute capital for labor, maintenance for fuel inefficiency, or to change the scale of operations. Each technique so devised allows the firm's management to vie with managers of competing firms for greater market dominance.

Natural monopoly removes the competitive characteristics from such activities. It has been determined in the United States that firms in natural monopolies serving the public interest require public controls as a substitute for the market controls normally expected to maintain competitive forces. These controls are vested in public regulatory agencies.

Prices in the publically controlled industries are established by determining rates or charges which will permit the utility to recover costs and provide a reasonable rate of return on the use of capital. Those determinations usually are made after the firm has requested a general rate hearing and has submitted sufficient evidence to support its application. There can be significant time lapses between the initial application and the final determination.

None of these conditions exists in a competitive market. As the product demand and production costs vary, the firm is relatively free to adjust price in order to sell its output and assure its investors an adequate return on equity capital. As production costs rise in an inflationary period, all other factors remaining the same, the firm in a competitive market will be able to adjust price accordingly. Public utility firms, on the other hand, may be granted permission to use an escalator factor called an automatic of fuel adjustment clause.

The general argument in support of the unavoidable cost-pass-through principle is that without an automatic adjustment clause, equity capital owners are unfairly exposed to inflation and its associated risks. Furthermore, if the unavoidable cost increases are not passed through to the consumer, the owners' capital will become eroded.

Exposure to the risks of inflation will result in lower bond ratings and stock prices so that higher interest and dividend rates will be required to attract the capital needed to maintain historical levels of service. These higher capital costs will then be passed on to the customer in the form of higher electric rates. The customer, in return for paying the higher capital costs, may be buffered against some of the effects of rapidly rising fuel costs. After some regulatory delay, the user will eventually pay the higher fuel costs as well. Although changes in the price to the customer will occur less frequently without FAC's, when these changes do occur they may be much larger and more abrupt.

While some cost increases will be unavoidable, the danger with FAC's is that the utility may attempt to pass through cost increases greater than those which are strictly unavoidable. That is, the extra cost increase is avoidable in the absence of the fuel clause.

Avoidable cost increases are those cost increases which are within the control of the utility given some specified level of output. Thus, to use the term avoidable costs in a meaningful way, we must refer to those costs which are partially avoidable, while the firm maintains some desired level of output. For example, through effective collective bargaining, a utility may avoid some labor costs without impairing its level of output.

Avoidable costs can be classified into two subcategories, the first being those avoidable costs that stem from paying too high a price for an input. For example, if the utility pays more than what is necessary to acquire a ton of coal, then this cost is avoidable in part. The second type of avoidable cost is associated with an input mix distortion. For example, if a utility incurs a higher fuel cost in an inefficient unit rather than incur a maintenance cost that cannot be passed through, then this cost also is avoidable. In this situation costs can be avoided simply by changing the proportion in which inputs are combined.

A properly designed FAC would ideally pass through all relevant unavoidable costs and pass through no avoidable costs to the consumer. Many expense items can plausibly be assumed to consist of both kinds of costs, but in practice they are extremely difficult to separate. A practical objective of regulation is to minimize avoidable costs.

There are two fundamentally different approaches to doing this. One approach is to design a FAC which contains incentives for the utility to minimize avoidable costs. The second approach involves having the regulatory agency act as a monitor, or watchdog, of utility fuel procurement and utilization practices. The two approaches can, of course, be used in combination.

Incentives And Monitoring Approaches

As mentioned, the incentives approach involves building the appropriate incentives directly into the FAC formula. The purpose is to provide disincentives for excess charges while at the same time providing positive incentives for economical performance and effective bargaining.

Developing the means to encourage utility managerial efficiency is a problem of the utility regulator whether a FAC is involved or not. Managerial efficiency means that a firm is getting the maximum output for a given set of inputs such as labor, fuel and capital.

Economic efficiency implies that the firm is combining its resources in the proper (i.e., cost minimizing) proportions and also is attaining managerial efficiency. It is quite possible that a firm could purchase resources in the wrong proportion and still get the maximum possible output from this set of resources. Managerial inefficiency is typically associated with poor managerial efforts at cost minimization. Thus, economic efficiency requires the absence of input distortion, as well as managerial efficiency. Fuel adjustment clauses that provide full recovery of costs will leave the utility with less incentive to minimize its actual costs.

In their article on FAC's and economic efficiency, Gollop and Karlson[1] examined the effect of FAC's on managerial efficiency. Using a sample of 105 utilities, Gollop and Karlson found evidence of FAC-related managerial inefficiency in the Northeast and Coal Belt regions

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[1] Frank M. Gallop and Stephen H. Karlson, "The Impact of the Fuel Adjustment Mechanism on Economic Efficiency," Review of Economics and Statistics, (November 1978), p. 581.

of the U.S. The authors could not find statistically convincing evidence of such inefficiency in the Gulf region.

The authors of that study speculate that their inability to observe managerial inefficiency in the Gulf region may be due to the common practice among Gulf state commissions of frequently revising upward the base price of fuel. By keeping the base price of fuel near the actual market price, utilities are in constant danger of having the market price fall below the base price, necessitating FAC credit payments to consumers. This situation, they contend, discourages managerial inefficiency in the use of fuel.[2]

The existence and degree of managerial inefficiency has been a long-standing question associated with regulated utilities. FAC's appear to aggravate this tendency toward inefficiency. The basic problem is that utilities are permitted to recover their costs and a fair rate of return on their investment, hence there may be insufficient incentive for firms to minimize their costs. Gollop and Karlson recommend continual monitoring as "the most effective means of preventing inefficient behavior."[3] However, an equally promising approach involves the use of built-in incentives to promote managerial efficiency.

The question is not whether to use an incentives approach or a monitoring approach. Both approaches are necessary in an FAC. The monitoring approach is required to detect improper charges. At a minimum this involves conventional audits to assure that costs are properly invoiced, calculated and billed. Regulatory hearings on fuel procurement and utilization practices of utility companies are another example of the watchdog approach. Extending the watchdog approach further to cover, for example, fuel contract negotiations requires significant regulatory expense and hence a significant avoidable cost of another kind. Even if regulatory staff members were to go so far as to sit in on these negotiations, it is unlikely that such a tactic would be effective in reducing avoidable fuel costs. Avoidable fuel costs are best reduced by long-term planning on the part of utility management so as

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[2] _Ibid._, p. 583.

[3] _Ibid._

to be in an effective bargaining position during contract negotiations. Motivation for such planning is difficult to promote by a watchdog approach. The required approach is one which builds into the FAC incentives for the utility to minimize avoidable costs.

The properly designed FAC will rely primarily on the incentives approach and employ a minimum of monitoring procedures. Regulatory hearings, in addition to increasing regulatory costs, may be ineffective in reducing fuel costs. In-depth hearings, to be useful, should be infrequent and directed toward a specific area of inquiry. Frequent general hearings, with insufficient time for staff preparation, could become a meaningless rubber-stamp process which merely gives the illusion of checking on fuel costs. Watchdog approaches, even when effective suffer from an after-the-fact effect. Problems are detected after they occur and require administratively cumbersome remedial action. In some circumstances, such action may be limited to the extent that it would cause financial damage to the utility involved.

The incentives approach, on the other hand, involves no regulatory cost once in place and produces a forward-looking effect. An FAC should have built-in incentives which encourage utilities to develop a strong bargaining position for future negotiations. Such an approach is directed toward the final outcome of the fuel procurement process rather than toward overseeing the process itself.

CHAPTER 5

DESIGNING FOR EFFICIENCY INCENTIVES

In this chapter opportunities for including in the FAC incentives, and avoiding disincentives, for efficient utility performance are discussed. The incentives considered here are economic incentives. Social incentives such as a civic responsibility for management are not considered. While such incentives can and should play a role, it is the business of regulators to assume that they cannot be relied upon. Although social incentives may usually preclude outright fraud, they cannot be presumed sufficient to motivate management to pursue aggressively, say, the lowest cost production alternatives.

Statewide Uniform Clause

It is advisable for a state utility regulatory agency to take the lead in setting a statewide uniform fuel adjustment clause for all electric utilities in its jurisdiction, rather than to allow each utility to propose its own FAC. A uniform clause is desirable for several reasons. First, it allows the agency to design a clause with acceptable efficiency incentives. Second, it allows the agency to define its terms uniformly and specify consistently which cost items are eligible for FAC inclusion and exclusion in that state. Third, it provides for a consistent method for calculating the rate increase or decrease for all utilities in the state.

Arguments that an individual utility is unique and cannot be treated adequately by a uniform clause are unpersuasive, since all major utilities engage in wholesale sales under the Federal Energy Regulatory Commission's uniform FAC.[1]

A properly designed FAC will precisely define the fuel costs allowable in the calculation and the corresponding kilowatt-hours. Included in this definition will be a specification of the time period for which these costs and kilowatt-hours are determined. The allowable fuel cost should include the fuel cost of the utility's own generation as well as the fuel cost attributable to sales not covered by the FAC. The corresponding kilowatt-hours should include self-generated power plus purchased power less the power sold but not covered by the FAC. Kilowatt-hours generated should be distinguished from kilowatt-hours sold. The purpose of precisely defining fuel costs and kilowatt-hours is to allow no increase in revenue in excess of the increase in costs.

Incentive Options

There are two types of incentive mechanisms to promote efficiency among utilities covered by FAC's. The first type of incentive uses the incomplete recovery of fuel costs or fuel-related costs to encourage fuel efficiency on the part of utilities. The second approach utilizes power plant productivity incentives to promote efficiency. Both of these incentive approaches have advantages and limitations.

The Incomplete Recovery of Costs

Many public utility commissions do not allow utilities to fully recovery their fuel expenses or fuel-related expenses in the belief that incomplete recovery will encourage utilities to minimize their costs of production.

Everyone agrees that utilities have the greatest incentive to hold down fuel cost increases if there is no FAC to provide for recovery of such increases. An FAC which provides for complete and assured recovery of fuel cost increases substantially eliminates this incentive. A

[1] FERC Order 517, Nov. 13, 1974.

middle ground is an FAC which allows partial recovery of fuel cost increases and a sharing between the utility and the customer of the benefits of fuel cost decreases. Such a clause can provide substantial incentive to hold the line on fuel costs while at the same time providing enough protection of the rate of return to protect the utility's position in the capital market.

There are various options for allowing a partial recovery of fuel cost increases. Before considering the options, one should note that this practice is well within the framework of traditional regulatory practice. It is merely the partial application of the principle of regulatory lag which has been the fundamental method for encouraging economical performance among regulated companies for more than a century. If operating expenses rise during the period between rate cases, the company has a reduced rate of return. If the company can decrease costs during this period, it earns a greater return. This performance incentive currently operates for most expenses of electric utilities: labor, maintenance, administration, and so on. There is nothing inherent in the fuel adjustment clause to require that fuel-related revenue adjustments exactly equal fuel cost changes. Most FAC's are designed to track changes in fuel prices only; changes in total fuel costs due to variations in sales or generation mix, but not due to changes in fuel prices, normally do not cause changes in the fuel adjustment, i.e., changes in the number of cents per kilowatt-hour paid for electricity. A properly designed FAC accurately <u>tracks</u> price changes, so that rates go up proportionally as fuel prices go up, but it does not necessarily provide the utility with revenue increases exactly equal to fuel cost increases.

In order to provide for efficiency incentives, it is important to keep in mind that the commission is under no obligation to use the FAC to make the utility immediately whole with regard to fuel cost increases any more than it is obliged to compensate the company immediately for increases in wage rates. In some states, in an effort to prevent recovery of revenues in excess of costs, legislatures have passed laws (or commissions have adopted rules) requiring that FAC revenues exactly equal fuel cost increases.

One simple option for partial recovery is to allow a pass-through of only a fixed percentage of fuel cost increases and decreases, for example, ninety percent.[2] In this case, the utility recovers 90% of any increase in fuel costs between rate cases: it may not pass through the other 10%. The justification is the same as that for not passing through other expense increases, namely, that the Commission decides to apply the principle of regulatory lag to a portion of fuel expense increases. Hence, the utility has an incentive to hold down cost increases. Moreover, an incentive exists for working hard to decrease fuel costs. The FAC would pass through to consumers 90% of the decrease, and the utility can keep the remaining 10%.

Holding back a small percentage of the fuel cost increase can be a major incentive. In a year of large fuel cost increases, the increase can be several times the company's allowed profit. A small percentage of the increase can be a significant fraction of allowed return.

Instead of allowing a percentage pass-through, another option which achieves a similar result is to disallow in the FAC increases in certain fuel-related expenses. Two candidates are the cost of gross receipts taxes and the cost of line losses. Of course, these expenses are recovered in the base rates, but under the principle of regulatory lag increases in these costs subtract from the company's profit and decreases in these costs add to earnings.

Let us consider the effect of disallowing each cost by means of a simplified example. Consider the case where there is no FAC provision for recovery of increases in a 5% gross receipts tax. Suppose fuel costs have increased by 1¢/kWh since the last rate case. Then, for every 100 kilowatt-hours sold, the company spends an extra $1 for fuel. The FAC provides for recovery of this dollar, but the company must pay 5¢ in tax on each dollar received. The company spends an extra dollar but recovers a net amount of only 95¢. Therefore, only 95% of any increases in fuel costs are recovered.

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[2] Both Michigan and South Dakota prohibit by law the FAC recovery of 10% of additional fuel costs incurred. Hence, the FAC in these states covers only 90% of actual fuel cost increases.

Consider next the case where no provision is made for recovery of the increased cost of energy lost in the transmission and distribution of electricity and of energy used by the company itself. All these are lumped together here as line losses. The fuel adjustment factor here is calculated as the ratio of increased fuel costs to kilowatt-hours generated (not sold, as in some FAC's). As in the previous example, assume that the cost of producing 100 kilowatt-hours has increased by $1. This 100 kilowatt-hours is measured at the generating plant--at the bus bar, to be precise. Then, the fuel adjustment is $1÷100 kWh = 1¢/kWh. Because of line losses, the company must produce 100 kWh in order to deliver 90 kWh to a certain customer. The additional revenue collected under the FAC is 90 kWh x 1¢/kWh = 90¢. Therefore, in this example only 90% of the fuel cost increase is recovered. The exclusion of line losses may be justified additionally because it encourages efficient transmission, distribution and self-use of energy.

Another incentive option is to introduce regulatory lag into the operation of the FAC itself. Again let us consider a simple example, in which there is a one month lag. Suppose fuel costs have been constant at $10 million per month. Ignore monthly variations in sales. Now assume that in May fuel costs increase to $12 million per month and remain at that level indefinitely. In each month before May, the utility paid out $12 million but recovers only $10 million because the fuel-cost-adjusted billings for May are based on the fuel costs for the prior month, April. (In some states the second or earlier prior month is used.) In June it again pays out $12 million, and so on. In every month except May, revenues match costs. In May, the utility suffers a "loss" of $2 million because fuel costs increased in that month. Therefore the utility has an incentive to avoid such cost increases. The incentive can be increased by increasing the number of months of lag.

The efficiency of the incentive also depends on whether the utility commission allows such losses as an expense in the next rate case, i.e. on whether inflation in fuel costs is judged a normal event likely to continue. For example, if the utility believes that all fuel expenses including avoidable ones will be recovered in the long run, there is little incentive for the utility to strive for cost minimization. In the final analysis, the effectiveness of any limited cost recovery incentive depends upon the ability of the utility commission to detect avoidable costs due to managerial inefficiency, input mix distortion, etc., and to disallow these costs.

Power Plant Productivity Incentives

The second approach to promoting utility cost minimization involves the use of incentives to encourage greater power plant efficiency. There are many alternative systems for encouraging cost savings. Some incentive systems such as the target capacity factors for nuclear plants in Connecticut and North Carolina involve an underrecovery of expense for poor performance. Other states allow a profit incentive for utilities which exhibit above average performance. For example, Michigan allows a higher rate of return on equity to firms with high plant availability.[3]

The primary hazard in applying any power plant incentive system is that it typically requires the public utility commission to select some indicator of utility performance and to prescribe an optimum level of performance. Normally this optimum or cost minimizing level of performance changes over time. It may depend upon input prices, market demand factors, existing capital structure, etc. The utility commission might need a considerable level of technical and economic sophistication to establish plant performance targets and to update these targets in response to changing conditions. Also, a target level of performance for one utility may not be appropriate for another utility.

A danger associated with performance incentives is that in attempting to cure managerial inefficiency and input mix distortions, they may easily introduce unintended side effects and input mix distortions of their own.[4]

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[3]Rodgers, Pozza and Burke, op. cit., pp. 162-166.

[4]For more in-depth discussion of the potential for, and difficulties with, use of power plant productivity targets, see Recommendations For Regulatory Actions To Promote Power Plant Productivity, by the NRRI Working Group on Power Plant Productivity, October 1979; available from the National Regulatory Research Institute, OSU, Columbus, Ohio.

Single-Factor Formula

The key element in a fuel clause is a formula for calculating the change in electric rates in terms of the change in fuel costs. One type of formula includes the heat rate; this is the two-factor formula. A type of formula which eliminates the heat rate factor is the single-factor formula. For the betterment of incentives a single-factor formula is preferred over a two-factor formula.

With a single-factor formula, the fuel cost in cents per kilowatt-hour is determined by adding up all the allowable fuel costs and dividing this sum by the appropriate number of kilowatt-hours. A two-factor formula, on the other hand, is one which initially calculates a system-wide weighted-average cost per thermal unit (in ¢/million BTU), then multiplies by the heat rate (in BTU/kWh), and divides the result by 1,000,000 to account for the use of a different thermal unit in each factor.

The single-factor formula is preferred, first of all because it is simple and promotes public understanding of the regulatory process. Furthermore, it leads to the same result as the two-factor formula for the case where the FAC uses a variable heat rate, i.e. it allows the recalculations of the heat rate every time the formula is applied. For the case where a fixed heat rate is used, the results obtained with the two formulas differ. While the fixed heat rate has the advantage that it encourages the utility to keep its generating plants thermally efficient, it has the overriding disadvantage that it provides a wrong incentive to minimize the actual monthly heat rate instead of giving an incentive to minimize the fuel cost per kilowatt-hour. The single factor approach eliminates the heat rate from the FAC formula.

The two-factor formula need be used only if the designer of the FAC believes that the fixed heat rate formula is preferable to the variable heat rate formula. The case in favor of a variable heat rate is presented later in this chapter.

Includable Costs

The FAC should of course cover only those costs believed to be substantially outside of the utility's control. For example, an automatic adjustment clause covering the labor costs of a utility would not be desirable as it could diminish the utility's incentive to bargain effectively with labor unions. When it is impossible to exclude all avoidable costs from an FAC clause, then it is necessary to provide the utility with a powerful incentive for minimizing these costs.

Thus in designing an FAC, an attempt should be made to exclude as many avoidable costs from coverage as possible. FAC's have covered such items as coal cost FOB at the mine, transportation from the mine, transfer costs en route to the plant, unloading costs at the plant, handling of the stockpile at the plant, coal treatment at the plant and ash disposal. The general rule to use in deciding whether or not a cost item should be covered under an FAC is that the more influence a utility has in determining the cost of an input, the less desirable it is that that resource should be included in the FAC's cost coverage. Hence, services performed by utility employees should not be covered under an FAC. For most utilities the unloading of fuel at the power plant, the stockpile handling at the plant, coal treatment at the plant and ash disposal should not be covered by an FAC, since these activities are typically performed by utility employees, thus involving costs over which the utility has a significant degree of control. The important thing to note here is that there is no official list of cost items which should always be included in or excluded from FAC provisions. Rather, some fuel-related costs that are substantially unavoidable for one firm may be avoidable for another firm. For example, transportation costs from the mine could properly be included in the FAC so long as these costs lie substantially outside the utility's control. However, if the utility owned its own railroad line, this could be sufficient reason for excluding transportation costs from FAC coverage, provided it would not result in an undesirable input distortion. Another example would be the treatment of transfer costs from the railhead to the plant. If the utility hires independent trucking companies at standard rates to perform this service, then these transfer costs might properly be regarded as unavoidable costs and be included in the FAC coverage. However, if the utility owns and operates its own trucks to perform this service then these costs are in large measure under the control of the utility and could be excluded from the FAC's cost coverage.

The public utility commission in charge of defining the cost coverage of a FAC must not allow much discretion for the utility in determining the costs which can be included under the FAC. In defining exactly which fuel and fuel-related costs are includable in the FAC, use of the FERC Uniform System of Accounts is useful.

For the purpose of promoting public understanding of the FAC, it is appropriate to separate the basic rates on each tariff into fuel costs and non-fuel costs on a per kilowatt-hour basis. The FAC is then a procedure for recalculating the fuel cost during each billing period. While the concept of a cost adjustment can be retained in the tariff, customers' bills would not state the adjustment explicitly. Instead the fuel cost per kilowatt-hour for the previous bill and for the current bill may be listed.

Input Mix Distortion

The design of an FAC should avoid giving the utility incentives for uneconomic behavior. The very existence of the FAC provides an incentive to be unconscientious regarding fuel costs if other costs, such as maintenance costs, which cannot be passed through in the FAC, can be avoided.

For example, in attempting to meet environmental standards, utilities which use coal have two basic alternatives: (a) they can switch to cleaner fuel, or (b) they can install some type of pollution control equipment. The "best" approach is to use whichever of these two alternatives yields the lowest cost way of meeting the environmental standard. However, FAC considerations may cause utilities not to choose the low cost method.

The first problem is that utilities may attempt to use more expensive cleaner burning coal in place of lower cost antipollution equipment because the higher price paid for fuel can be more easily recovered through the FAC. This problem is similar to the input mix distortion discussed previously and it can affect the utility irrespective of the type of heat rate used in the FAC.

Compounding the problem is the fact that one frequently-used capital intensive alternative to clean burning coal also has an effect on thermal efficiency. Stack scrubbers will typically increase (i.e. deteriorate) a utility's heat rate by 20 to 25 percent. The utilities operating under a fixed heat rate FAC will be penalized if they install scrubbers, unless the heat rate is adjusted upward. The basic principle here is that FAC's may encourage expensive fuel switching alternatives over potentially more economical capital intensive methods of controlling pollution.

Regardless of the heat rate used in the FAC, the FAC may distort the input mix in favor of a more expensive (e.g., clean burning) fuel relative to a cheaper fuel, since higher fuel prices lead to a higher regulated price of electricity. This distortion of the fuel mix will be softened if the more expensive grade of fuel also produces more BTU's per ton, since often FAC's make adjustments only for changes in the cost of producing a given amount of heat. Even with only fuel and fuel related costs considered, a poorly designed FAC may give a utility an incentive to minimize costs excluded from the formula at the expense of minimizing the overall costs of generation.

Avoidance of input-mix distortion argues for inclusion of nuclear fuel costs, purchased power expenses, the cost of coal from captive mines, and coal transportation expenses in the FAC. It also makes use of the fixed heat rate undesirable.

Fuel costs from all generating plants, including nuclear, should be included in the FAC to prevent excess revenue recovery and avoidance of cost minimization. It may be argued that nuclear fuel costs should be outside the FAC because such costs are relatively stable. Setting aside the question of stability which may or may not be valid in the future, the case presented here for including nuclear fuel is based solely on the problem of input mix distortion. If the FAC applies to fossil fuel only then the possibility exists for the utility to recover extra revenue by uneconomical performance. To see this, suppose the cost of nuclear fuel is included in the basic rates and the FAC does not provide for a reduction in rates when less nuclear fuel is consumed. It does provide for an increase in rates when more fossil fuel is consumed. This creates an incentive for the utility to shift its usage of plant types toward fossil so as to receive duplicate recovery of fuel costs, even though this shift might increase the cost of providing service.

Also, the utility has an incentive not to increase the use of its nuclear plants even though this could lower system costs. This is because the FAC lowers revenues when less fossil fuel is consumed, but does not increase revenues when more nuclear fuel is consumed. Because the cost of nuclear fuel is much less than the cost of fossil fuel, a shift from fossil toward nuclear would benefit consumers. Therefore, a FAC which does not include nuclear generation creates a situation in which the utility's interests are opposed to consumers' interests.

The inclusion of a provision governing electric power purchased from or sold to another utility is needed for any well-designed FAC. The well-designed FAC encourages the exchange of power among utilities when it leads to a more efficient, lower cost production of electricity. Utilities typically resort to purchased power when electricity can be purchased for a lower cost than it can be generated or when available generating capacity cannot meet the demand.

Care must be taken in the design of an FAC so as not to promote (or discourage) the use of purchased power beyond an economically justifiable level. Exclusion of purchased power costs could create an undue incentive to rely on self-generated power.

Another question relates to the inclusion of changes in the price of coal from captive mines in a FAC provision. A captive mine is simply a utility-owned mine. One answer is to disallow all fuel cost increases associated with the output of a captive mine from coverage under an FAC on the grounds that these costs are to some extent under the direct control of the utility (i.e., avoidable costs). While this may help to avoid exorbitant charges or managerial inefficiency in captive mining, it may also serve to discourage utilities from developing captive mines, which can be useful to utilities in bargaining for lower coal prices.

Therefore, it is probably beneficial to allow such costs in the FAC, although they should be the subject of extra scrutiny.

The argument in favor of including transportation cost changes in an FAC is as follows. To do otherwise would give a utility an incentive to purchase fuel only from nearby suppliers and so limit transportation cost increases if these cannot be recouped. Yet the overall cost of fuel, purchase price plus transportation, may be lower from a distant supplier. Similarly, the use of a fixed heat rate in the FAC formula gives incentive for input mix distortion. With a fixed heat rate, the utility has an incentive to use its most fuel efficient units even though these units may consume more costly fuel.

The objective in FAC is to minimize the overall cost. Development of incentives for individual cost items or for certain productivity targets can create incentives which work against overall cost minimization. If such specific incentives and targets are used, a close monitoring of the utility is required to detect abuses.

CHAPTER 6
MONITORING PROCEDURES

Introduction

With the widespread adoption of FAC's, there has been a concomitant effort to intensify the monitoring of utilities. In many states the fuel clause has been either attacked, repealed or modified. As a result of recent widespread disenchantment with FAC's, since 1970 at least six states have authorized special FAC hearings before approval of an FAC rate change can be granted. Table 3-5 indicated the frequency of review procedures used by state commissions in monitoring the fuel adjustment clause. Such procedures include routine filing of FAC calculations, a check of FAC computations, audits of fuel costs and fuel procurement practices, spot checks of operating facilities and FAC and fuel cost hearings.

The monitoring approach involves providing the regulatory agency with special duties and powers aimed at detecting avoidable utility related costs. This "watchdog" or "monitor" approach, at a minimum, would involve conventional audits to assure that costs were properly calculated and billed. The watchdog method might also be extended to involve more intensive investigations and/or hearings aimed at assessing whether or not utilities bargained effectively and in other ways performed in the best public interest.

A common criticism confronting regulatory commissions regarding automatic adjustment clauses is that such clauses result in the relinquishing of regulatory control. A second major criticism is that the incentive for operating efficiently is dampened since fuel costs are automatically passed through on a monthly basis.

The validity of at least the second criticism is inversely related to (1) the comprehensiveness of the design of the adjustment clauses and (2) the effectiveness of the process for administering the adjustment clauses. Uniformly designed adjustment clauses, which define specifically those costs allowable for pass-through, can provide for the timely reporting and review of such costs and require periodic verification of operating practices and procedures of the utility to assure that appropriate regulatory control is maintained.

Given uniformly designed adjustment clauses which define specifically these costs allowable for pass-through, the primary objectives of the administrative process are (1) to provide for the timely reporting and review of such costs and (2) to ensure that the operating practices and procedures of the utility are comprehensively analyzed and reviewed periodically.

To accomplish these objectives effectively, the administrative process can include the following:

- uniform reporting requirements to provide the commission with key data to verify the pass-through charge and monitor the primary variables affecting system costs;
- clearly assigned responsibility and specific procedures for review and analysis of data reported by the utilities on a timely basis;
- a comprehensive audit of the operations of the utility under the adjustment clause on an annual basis;
- a formal hearing and review before the commission of the operation of the utility for the purpose of determining compliance with the adjustment clause and determining any reconciliation adjustments required.

Each feature of the administrative process should be designed to enable the commission to gather, analyze and review sufficient evidentiary material necessary 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.

An obvious disadvantage of the monitoring approach is that it involves potentially quite substantial regulatory costs. Also, once this approach is carried beyond conventional audit procedures, methodological problems arise, since there are no methods of established validity for determining if a utility has effectively bargained with its suppliers. Another deficiency of the monitoring approach is its after-the-fact posture. That is, problems are always detected after they occur when remedial action by the regulatory agency may cause the utility significant financial harm. For example, suppose an FAC distorts the input mix in favor of using a more fuel intensive technology, i.e., choosing to construct a coal plant rather than a nuclear plant. The utility's investment in coal-fixed generating facilities may hinder effective remedial action, since the utility would sustain substantial loss in reversing its decision.

In this chapter, monitoring procedures are discussed as they were developed by the staff of the NRRI working with the staffs of the Public Utilities Commission of Ohio,[1] the Illinois Commerce Commission,[2] and the Virginia Corporation Commission.[3] The procedures described here represent a generalized approach, not one fine tuned to the requirements of one of these states. (The detailed requirements can be found in the works cited.) As such, this chapter contains a model set of procedures for reviewing fuel cost changes which can be adapted by any state commission to meet its own requirements.

It is assumed in this chapter that the commission has access to a computer and can require monthly utility submission of fuel cost data on computer tape for timely and in-depth analyses of fuel costs. For commissions without computer capability, the outline of procedures discussed here represents a useful framework for establishing a less comprehensive analysis of fuel cost data.

The appendix of this report contains a complete description of all

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[1] S. Goldstone and K. Kelly, Ohio's Fuel Adjustment Clause: An Analysis and Recommendations for Change (Columbus: National Regulatory Research Institute, The Ohio State University, November 1975).

[2] NRRI and Touche Ross, Uniform Electric and Gas Adjustment Clauses for the Illinois Commerce Commission (Columbus: National Regulatory Research Institute, The Ohio State University, September 1979).

[3] NRRI Staff, A Description of the Virginia State Corporation Commission's Production Cost Simulation Model (Columbus: National Regulatory Research Institute, The Ohio State University, April 1979).

data that might be requested by a regulatory agency from an electric utility for monthly fuel adjustment clause reporting. It contains the necessary information on each item required in order to request its submission on computer tape: field identification number, FORTRAN element name, common (i.e., in English) name, units of measurement, and attribute (FORTRAN format). Material in the appendix draws from an FAC data dictionary prepared by the NRRI for the Virginia Corporation Commission in May of 1979. This data dictionary represents a complete reworking of an earlier computerized fuel cost reporting system developed by present members of the NRRI staff in the fall of 1975 for the Public Utilities Commission of Ohio.

The monitoring procedures associated with fuel adjustment clause operation in most states include periodic reports, review of periodic reports, audits, and hearings covering fuel procurement and utilization practices.

Reporting

Uniform reporting of key cost, revenue and operating data should be required for each adjustment. Such reporting by the utility can then precede the billing of the adjustment charge. This will enable the commission to perform a review of the adjustment charge calculation prior to customers receiving billing of the pass-through.

Every month each utility should submit detailed fuel cost information in a form suitable for computer processing. This information consists basically of the data submitted monthly by utilities to the FERC on Form 423, and also information on fuel suppliers, price changes, fuel quality, use of various generating plant types, heat rate data and related data. This information is processed by a computer program that can be handled by a single member of the staff. It not only checks the arithmetic accuracy of the fuel adjustment calculation but also flags unusual circumstances which might require review by other Commission staff members.

In addition, the commission may require an annual report covering annual data on fuel purchases and fuel utilization practices.

Rules provide that avoidable costs found in the monthly review or in the annual audit be refunded to the utility's customers by means of an adjustment in future fuel charges.

Examples of the categories and types of data to be reported and reviewed monthly include:

A. Cost data

1. Includable/excludable costs as defined by the clause,

2. Costs in accordance with the uniform system of accounts.

B. Revenue data

1. Costs recovered through billings associated directly with the pass through.

2. Quantification of the over/under position of the utility for the reporting period and the year to date.

C. Operating data

1. Includable/excludable energy as defined by the clause,

2. Key non-cost variables affecting system average cost such as:

a. System heat rate
b. Line loss
c. Sales
d. Mix of fuels
e. Mix of internal/external generation
f. Plant and unit capacity factors

Review

A monthly review, or "desk audit," of data reported by the utility can be performed prior to the application of the pass-through charge to customers' bills. The "desk audit," while not necessarily verifying the data reported in company source records, would:

1. test the arithmetic accuracy of the pass-through change computation;

2. verify proper application of the calculation methodology; and

3. provide necessary input to determine the reasonableness of operating data via comparison to prior periods and compliance with rules which the commission may define.

The review would result in a report which contains findings of exceptions, such as

1. data omissions or inaccuracies
2. computational errors
3. improper calculation method
4. suspicious data
5. monthly and year-to-date summaries of fuel costs and FAC revenues

Failure to resolve the exceptions to the satisfaction of the commission prior to the date of FAC application would result in either suspension of the FAC adjustment for the billing period or continuation of the previous month's adjustment.

Audit

A commission-initiated fuel audit, performed or administered by the commission staff, should be undertaken annually to determine whether reconciliation adjustments need to be ordered. The audit scope should be comprehensive and address both the financial data as well as overall operating performance of the utility.

The financial aspects of the audit should be designed to

1. verify the validity and accuracy of reported cost and recovery data with respect to company source documents;
2. assure the utility has properly applied the computation methodology; and
3. determine the settlement position of the utility as well as quantify reconciliation adjustments required.

The operating performance review aspects of the audit should be designed to:

1. evaluate the utility's policies, procedures and controls, particularly in the areas of fuel procurement, system operations, and accounting;
2. review and evaluate fuel contracts;
3. recommend and quantify, wherever possible, performance improvement opportunities.
4. identify operating behavior that seeks to minimize costs that can be passed through the FAC at the expense of minimizing overall cost of service.

Hearing

Subsequent to the audit, a formal fuel cost hearing before the commission should be required. The hearing would provide the formal proceedings for review of the operations of the utility under the adjustment clause. The findings of the commission staff review and the annual audit would provide the basis for evaluating the compliance of the utility with the adjustment clause and determining any settlement amount required and the reconciliation method to be employed.

APPENDIX

DATA FOR A COMPUTERIZED MONITORING SYSTEM

The staff of NRRI and the staff of the Virginia State Corporation Commission (VSCC) have developed a reporting and monitoring system to evaluate the fuel purchase costs and fuel usage practices of the electric utilities serving the Commonwealth of Virginia. The development of this system was carried out under contract with The National Regulatory Research Institute. The monitoring system requires periodic reporting of fuel purchase and usage data to the Commission. Most data are required monthly; other data are required by calendar quarter or annually, as specified by the Commission.

This appendix contains the data dictionary to be used for reporting. The purpose of this data dictionary is to facilitate the submission of data in computer compatible format. For each data element there is:

(1) a field number which indicates the location of the element in the data dictionary field structure,
(2) an element name in FORTRAN for use by VSCC programmers,
(3) a full name and definition of the element,
(4) the units in which the element is to be measured for reporting, and
(5) an element attribute which defines the FORTRAN format in which to record the element.

Data should be reported for the reporting period. For example, under heat rate a generating unit's actual average heat rate during a month is required if the reporting period is a month. If the reporting period is a calendar quarter, the heat rate averaged over the quarter is required.

The data dictionary is made up of three data sets: system data, plant data, and unit data. Net generation by the whole company system during the reporting period would be reported as part of the system data; net generation by a particular plant in the system would be reported under "net generation" in the plant data set; and net generation by an individual unit at a plant would be reported as unit data.

For each reporting period, the system data set is completed once. The plant data set is completed for each plant in the system, and the unit data set is completed for each unit in the system.

In each data set, the data are grouped into branches containing related data. For example, within the unit data set, the first branch contains fixed parameters, that is, data--such as fraction of ownership by the reporting company--that is not likely to change from one reporting period to the next. The second branch contains data on the generation and operation of units other than hydroelectric units. The data required here are broken into subgroups called records: one record for demand, another for generation, and so on. By contrast, the first unit branch requires no subgrouping and so contains only one record. There is no further subgrouping: each record contains data elements in a particular order as determined by the assigned field number.

APPENDIX

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TABLE OF CONTENTS (continued)

SYSTEM DATA - 6 Branches

I FUEL CHARGE ADJUSTMENT FACTORS - 1 record (3 elements)

II SYSTEM SALES DATA - 1 record (18 elements)

III SYSTEM ENERGY AND LOAD DATA - 3 records

1.	System Generation	(33 elements)
2.	Inter-System Energy Sales and Purchases	(14 elements)
3.	System Load	(5 elements)

IV SYSTEM FUEL CONSUMPTION DATA - 1 record (25 elements)

V SYSTEM ACCOUNTING ADJUSTMENTS BY FUEL TYPE - 1 record (40 elements)

VI SYSTEM FUEL PURCHASE DATA - 17 records

1.	Total Fuel Purchases	(8 elements)
2.	Total Coal Purchases	(20 elements)
3.	Spot Coal Purchases	(20 elements)
4.	Broker Coal Purchases	(20 elements)
5.	Affiliate Coal Purchases	(20 elements)
6.	Non-affiliate Coal Purchases	(20 elements)
7.	Total Oil Purchases	(12 elements)
8.	Total Light Oil Purchases	(12 elements)
9.	Spot Light Oil Purchases	(12 elements)
10.	Broker Light Oil Purchases	(12 elements)
11.	Contract Light Oil Purchases	(12 elements)
12.	Total Heavy Oil Purchases	(12 elements)
13.	Spot Heavy Oil Purchases	(12 elements)
14.	Broker Heavy Oil Purchases	(12 elements)
15.	Contract Heavy Oil Purchases	(12 elements)
16.	Natural Gas Purchases	(4 elements)
17.	Nuclear Fuel Acquisition Costs	(4 elements)

SYSTEM DATA (6 Branches)
1st BRANCH: FUEL CHARGE ADJUSTMENT FACTORS
Record 1 of 1

FUEL CHARGE ADJUSTMENT FACTORS (3 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	FFLEVL	LEVELIZED FUEL FACTOR CHARGE	¢/kWh	F7.5
		The levelized fuel factor charge is an average charge in cents per kilowatt-hour to all customers. This charge is an adjustment to the base fuel factor charge made in order to bring fuel revenue recoveries in line with projected annual fuel expenses. The levelized fuel factor charge includes the gross receipts tax adjustment.		
2	FFBASE	BASE FUEL FACTOR CHARGE	¢/kWh	F7.5
		The base fuel factor charge is the fuel charge in the base rates found to be appropriate in the last rate case. This charge is the average charge in cents per kilowatt-hour to all customers.		
3	FFTOTL	TOTAL FUEL FACTOR CHARGE	¢/kWh	F7.5
		The total fuel factor charge is the sum of the levelized fuel factor charge and the base fuel factor charge. It is the total fuel charge in cents per kilowatt-hour, to all customers, for revenues to recover allowable fuel clause expenses.		

SYSTEM DATA (6 Branches)
2nd BRANCH: SYSTEM SALES DATA
Record 1 of 1

SYSTEM SALES DATA (18 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		TOTAL SALES DATA		
1	SULTCS	TOTAL SALES TO ULTIMATE CUSTOMERS - ALL JURISDICTIONS	MWH	I8
		This account will contain the total sales of power to ultimate customers, measured in megawatt hours (MWH), in all jurisdictions.		
2	SRES	SALES FOR RESALE - ALL JURISDICTIONS	MWH	I8
		This account will contain the total sales of power, on a wholesale basis to public authorities, utilities or cooperatives, in all jurisdictions. The sales are measured in megawatt hours.		
3	PUREN	TOTAL PURCHASED ENERGY	MWH	I8
		Total purchased energy is the amount, measured in MWH, that is purchased from other utilities, rather than internally produced.		
4	COMPUS	COMPANY USED ENERGY	MWH	I8
		Company used energy, in MWH, is the energy used internally by the company in its generation processes like in firing up generators and pumping water for storage.		
5	ENLOSE	ENERGY LOSSES	MWH	I8
		Energy losses are the difference between what is produced at the plant and what reaches consumers due to line losses. These losses are measured in megawatt hours.		

SYSTEMS SALES DATA (18 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		JURISDICTIONAL SALES		
6	VASALE	VIRGINIA SALES TO ULTIMATE CUSTOMERS	MWH	I8
		This account contains the total sales to ultimate customers in Virginia of power measured in megawatt hours.		
7	NCSALE	NORTH CAROLINA SALES TO ULTIMATE CUSTOMERS	MWH	I8
		This account contains the total sales to ultimate customers in North Carolina of power measured in megawatt hours.		
8	WVSALE	WEST VIRGINIA SALES TO ULTIMATE CUSTOMERS	MWH	I8
		This account contains the total sales to ultimate customers in West Virginia of power measured in megawatt hours.		
9	DCSALE	WASHINGTON, D.C. SALES TO ULTIMATE CUSTOMERS	MWH	I8
		This account contains the total sales to ultimate customers in Washington, D.C. of power measured in megawatt hours.		
10	MDSALE	MARYLAND SALES TO ULTIMATE CUSTOMERS	MWH	I8
		This account contains the total sales to ultimate customers in Maryland of power measured in megawatt hours.		
11	DLSALE	DELAWARE SALES TO ULTIMATE CUSTOMERS	MWH	I8
		This account contains the total sales to ultimate customers in Delaware of power measured in megawatt hours.		

SYSTEMS SALES DATA (18 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		VIRGINIA JURISDICTIONAL SALES BY CUSTOMERS CLASS		
12	VACL1	VIRGINIA SALES TO CUSTOMER CLASS 1 This class shall include the amount of electricity supplied to residential customers. The sales are registered in account #440 of the Uniform System of Accounts.	MWH	I8
13	VACL2	VIRGINIA SALES TO CUSTOMER CLASS 2 This class shall include the amount of electricity supplied to commercial and industrial customers. The sales are registered in account #442 of the Uniform System of Accounts.	MWH	I8
14	VACL3	VIRGINIA SALES TO CUSTOMER CLASS 3 This class shall include the amount of electricity supplied to government units for the lighting of public places like streets, highways, and parks. The sales are registered in account #444 of the Uniform System of Accounts.	MWH	I8
15	VACL4	VIRGINIA SALES TO CUSTOMER CLASS 4 This class shall include the amount of electricity supplied to public authorities for all uses except for public lighting above. The sales are registered in account #445 of the Uniform System of Accounts.	MWH	I8
16	VACL5	VIRGINIA SALES TO CUSTOMER CLASS 5 This class shall include the amount of electricity supplied to railroads and railways. The sales are registered in account #446 of the Uniform System of Accounts.	MWH	I8

SYSTEM SALES DATA (18 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
17	VACL6	VIRGINIA SALES TO CUSTOMER CLASS 6 This class shall include the amount of electricity supplied to other electric utilities or public authorities for resale purposes. The sales are registered in account #447 of the Uniform System of Accounts.	MWH	I8
18	VACL7	VIRGINIA SALES TO CUSTOMER CLASS 7 This class shall include the amount of electricity supplied one electric utility department to another (inter-departmental sales). The sales are registered in account #448 of the Uniform System of Accounts.	MWH	I8

SYSTEM DATA (6 Branches)
3rd BRANCH: SYSTEM ENERGY AND LOAD DATA
Record 1 of 3

SYSTEM GENERATION (33 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	GGCOAL	GROSS GENERATION BY COAL	MWH	I8
		The total electric energy generated from coal in the entire system during the reporting period.		
2	GGNUCL	GROSS GENERATION BY NUCLEAR	MWH	I8
		The total electric energy generated from nuclear fuel in the entire system during the reporting period.		
3	GGOIL	GROSS GENERATION BY OIL	MWH	I8
		The total electric energy generated from oil in the entire system during the reporting period.		
4	GGF02	GROSS GENERATION BY LIGHT FUEL OIL	MWH	I8
		The total electric energy generated from light fuel oil in the entire system during the reporting period.		
5	GGF04	GROSS GENERATION BY HEAVY FUEL OIL	MWH	I8
		The total electric energy generated from heavy fuel oil in the entire system during the reporting period.		
6	GGNGAS	GROSS GENERATION BY NATURAL GAS	MWH	I6
		The total electric energy generated from natural gas in the entire system during the reporting period.		
7	GGHYDR	GROSS GENERATION BY HYDRO	MWH	I6
		The total electric energy generated from hydroelectric facilities in the entire system during the reporting period.		
8	SYTGG	SYSTEM TOTAL GROSS GENERATION	MWH	I8
		The total electric energy generated in the entire system during the reporting period.		

SYSTEM GENERATION (33 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
9	NGCOAL	NET GENERATION BY COAL	MWH	I8
		The system gross generation from coal less the auxiliary energy required by the system.		
10	NGNUCL	NET GENERATION BY NUCLEAR	MWH	I8
		The system gross generation from nuclear fuel less the auxiliary energy required by the system.		
11	NGOIL	NET GENERATION BY OIL	MWH	I8
		The system gross generation from oil less the auxiliary energy required by the system.		
12	NGF02	NET GENERATION BY LIGHT FUEL OIL	MWH	I8
		The system gross generation from fuel oil no. 2 less the auxiliary energy required by the system.		
13	NGF04	NET GENERATION BY HEAVY FUEL OIL	MWH	I8
		The system gross generation from fuel oil no. 4 less the auxiliary energy required by the system.		
14	NGNGAS	NET GENERATION BY NATURAL GAS	MWH	I6
		The system gross generation from natural gas less the auxiliary energy required by the system.		
15	NGHYDR	NET GENERATION BY HYDRO	MWH	I6
		The system gross generation from hydroelectric facilities less the auxiliary energy required by the system.		
16	GGTOTL	SYSTEM TOTAL NET GENERATION	MWH	I8
		The system gross generation less the auxiliary energy required by the system.		
17	GGBASE	GROSS GENERATION BY BASE UNITS	MWH	I8
		The total electric energy generated from base load units in the entire system during the reporting period.		

SYSTEM GENERATION (33 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
18	GGCYCL	GROSS GENERATION BY CYCLING UNITS The total electric energy generated from cycling units in the entire system during the reporting period.	MWH	I8
19	GGPEAK	GROSS GENERATION BY PEAKING UNITS The total electric energy generated from peaking units in the entire system during the reporting period.	MWH	I7
20	GGHYDR	GROSS GENERATION BY HYDRO The total electric energy generated from hydroelectric facilities in the entire system during the reporting period.	MWH	I6
21	GGNALL	SYSTEM TOTAL GROSS GENERATION The total electric energy generated in the entire system during the reporting period.	MWH	I8
22	NGBASE	NET GENERATION BY BASE UNITS The system gross generation from base load units less the auxiliary energy required by the system.	MWH	I8
23	NGCYCL	NET GENERATION BY CYCLING UNITS The system gross generation from cycling units less the auxiliary energy required by the system.	MWH	I8
24	NGPEAK	NET GENERATION BY PEAKING UNITS The system gross generation from peaking units less the auxiliary energy required by the system.	MWH	I7
25	NGHYDR	NET GENERATION BY HYDRO The system gross generation from hydroelectric facilities less the auxiliary energy required by the system.	MWH	I6

SYSTEM GENERATION (33 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
26	NGNALL	SYSTEM TOTAL NET GENERATION	MWH	I8
		The system gross generation less the auxiliary energy required by the system.		
27	THCOAL	THERMAL ENERGY PRODUCTION FROM COAL	MMBTU	I9
		The total thermal energy generated from coal in the entire system during the reporting period.		
28	THNUCL	THERMAL ENERGY PRODUCTION FROM NUCLEAR	MMBTU	I9
		The total thermal energy generated from nuclear fuel in the entire system during the reporting period.		
29	THOIL	THERMAL ENERGY PRODUCTION FROM OIL	MMBTU	I9
		The total thermal energy generated from all fuel oil in the entire system during the reporting period.		
30	THF02	THERMAL ENERGY PRODUCTION FROM LIGHT FUEL OIL	MMBTU	I9
		The total thermal energy generated from light fuel oil in the entire system during the reporting period.		
31	THF04	THERMAL ENERGY PRODUCTION FROM HEAVY FUEL OIL	MMBTU	I9
		The total thermal energy generated from heavy fuel oil in the entire system during the reporting period.		
32	THNGAS	THERMAL ENERGY PRODUCTION FROM NATURAL GAS	MMBTU	I7
		The total thermal energy generated from natural gas in the entire system during the reporting period.		
33	THTOTL	SYSTEM TOTAL THERMAL ENERGY PRODUCTION	MMBTU	I9
		The total thermal energy generated in the entire system during the reporting period.		

INTER-SYSTEM ENERGY SALES AND PURCHASES (14 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	PTYPE	PURCHASE TYPE		I2
		The two-digit number identifying the type of energy purchase. See Exhibit A for a list of numbers.		
2	PFROM	SELLER		I6
		The six-digit number identifying the company from which the energy is purchased.		
3	PENGY	AMOUNT OF PURCHASED ENERGY	MWH	I7
		The amount of energy purchased during the reporting period under the purchase transaction being reported.		
4	PDEMCT	DEMAND COST	$	I7
		The dollar amount paid or payable that accounts for the readiness of the seller to supply power (kilowatts), prorated if necessary to cover only the reporting period.		
5	PENGCT	ENERGY COSTS	$	I7
		The dollar amount paid or payable for the electric energy (kilowatt-hours) purchased during the reporting period.		
6	PFULCT	FUEL COST	$	I7
		The dollar amount that represents the fuel portion of the energy costs.		
7	PTOTAL	TOTAL COST	$	I7
		The total dollar amount paid or payable under the energy purchase transaction being reported.		

INTER-SYSTEM ENERGY SALES AND PURCHASES (14 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		INTERSYSTEM ENERGY SALES		
8	STYPE	TYPE OF ENERGY SALE		I2
		The two-digit number identifying the type of intersystem energy sale. See Exhibit A for a list of numbers.		
9	SOLDTO	BUYER		I6
		The six-digit number identifying the company to which the energy is sold.		
10	SENGY	AMOUNT OF ENERGY SOLD	MWH	I7
		The amount of energy sold for resale during the reporting period under the sales transaction being reported.		
11	SDEMCH	DEMAND CHARGE	$	I7
		The dollar amount received or receivable that accounts for the readiness to supply power (kilowatts), prorated if necessary to cover only the reporting period.		
12	SENGCH	ENERGY CHARGE	$	I7
		The dollar amount received or receivable for the electric energy (kilwatt-hour) sold for resale during the reporting period.		
13	SFULCH	FUEL CHARGE	$	I7
		The dollar amount that represents the fuel portion of the energy charge.		
14	STOTAL	TOTAL CHARGE	$	I7
		The total dollar amount received or receivable under the intersystems sales transaction being reported.		

SYSTEM DATA (6 Branches)
3rd BRANCH: SYSTEM ENERGY AND LOAD DATA
Record 3 of 3

SYSTEM LOAD DATA (5 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	MOPEAK	PEAK DEMAND FOR REPORTING PERIOD	MW	I5
		The system peak demand for the reporting period is required.		
2	MOBASE	MINIMUM DEMAND FOR REPORTING PERIOD	MW	I5
		The system minimum demand for the reporting period is required.		
3	LODFAC	LOAD FACTOR	%	F5.2
		Load factor is the ratio of (a) the megawatt-hour generation during the reporting period, to (b) the product of the system capacity in megawatts and the number of hours in the reporting period.		
4	SYSCAP	SYSTEM CAPACITY	MW	I5
		The total rated capacity of all units owned within the system is reported.		
5	REMARG	RESERVE MARGIN	%	F5.2
		Reserve margin is $\frac{\text{SYSCAP - MOPEAK}}{\text{MOPEAK}} \times 100\%$.		

SYSTEM DATA (6 Branches)
4th BRANCH: SYSTEM FUEL CONSUMPTION DATA
Record 1 of 1

SYSTEM FUEL CONSUMPTION DATA (25 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		FIRST FUEL TYPE		
1	S1TYPE	FUEL TYPE		I1

Enter one of the following numbers, for the fuel used to generate the most energy in the system.

1 coal
2 nuclear
3 light fuel oil
4 heavy fuel oil
5 natural gas

2	S1BTUC	AVERAGE COST OF FUEL CONSUMED	¢/MMBTU	F7.3

The average cost of primary fuel consumed is the weighted average cost per MMBTU of the fuel consumed during the reporting period. For a fossil fuel, it is the weighted average cost of the fuel consumed during the period. For nuclear fuel, it is the amortization of the burn for all in-core assemblies divided by the gross heat generation in millions of BTUs. For both fossil and nuclear fuels, this average cost does not include cost components not allowed in the Virginia fuel clause.

3	S1QCN	QUANTITY OF FUEL CONSUMED	(UNIT)	I8

The total number of units of the fuel consumed for generation in tons, barrels, MCF, etc. For nuclear fuel, enter the gross heat generation in megawatt-days.

4	S1AHCN	AVERAGE HEAT CONTENT OF FUEL CONSUMED	BTU/(UNIT)	I8

The weighted average heat content of the fuel in BTUs per delivered unit (e.g. BTUs/lb., BTUs/gal., BTUs/MCF, BTUs/assembly, etc.).

SYSTEM FUEL CONSUMPTION DATA (25 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
5	S1TUTC	TOTAL COST OF FUEL CONSUMED	$	I9

The total cost of the fuel consumed for generation in the system in thousands of dollars is reported. This cost does not contain cost components not allowable in the Virginia fuel clause.

SECOND FUEL TYPE

6	S2TYPE	FUEL TYPE		I1

Enter one of the following numbers, for the fuel used to generate the second most energy in the system.

1 coal
2 nuclear
3 light fuel oil
4 heavy fuel oil
5 natural gas

7	S2BTUC	AVERAGE COST OF FUEL CONSUMED	¢/MMBTU	F7.3

The average cost of secondary fuel consumed is the weighted average cost per MMBTU of the fuel consumed during the reporting period. For a fossil fuel, it is the weighted average cost of the fuel consumed during the period. For nuclear fuel, it is the amortization of the burn for all in-core assemblies divided by the gross heat generation in millions of BTUs. For both fossil and nuclear fuels, this average cost does not include cost components not allowed in the Virginia fuel clause.

8	S2QCN	QUANTITY OF FUEL CONSUMED	(UNIT)	I8

The total number of units of the fuel consumed for generation in tons, barrels, MCF, etc. For nuclear fuel, enter the gross heat generation in megawatt-days.

9	S2AHCN	AVERAGE HEAT CONTENT OF	BTU/(UNIT)	I8

The weighted average heat content of the fuel in BTUs per delivered unit (e.g. BTUs/lb., BTUs/gal., BTUs/MCF, BTUs/assembly, etc.).

SYSTEM FUEL CONSUMPTION DATA (25 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
10	S2TUTC	TOTAL COST OF FUEL CONSUMED	$	I9

The total cost of the fuel consumed for generation in the system in thousands of dollars is reported. This cost does not contain cost components not allowable in the Virginia fuel clause.

THIRD FUEL TYPE

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
11	S3TYPE	FUEL TYPE		I1

Enter one of the following numbers, for the fuel used to generate the third most energy in the system.

1 coal
2 nuclear
3 light fuel oil
4 heavy fuel oil
5 natural gas

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
12	S3BTUC	AVERAGE COST OF FUEL CONSUMED	¢/MMBTU	F7.3

The average cost of the third fuel consumed is the weighted average cost per MMBTU of the fuel consumed during the reporting period. For a fossil fuel, it is the weighted average cost of the fuel consumed during the period. For nuclear fuel, it is the amortization of the burn for all in-core assemblies divided by the gross heat generation in millions of BTUs. For both fossil and nuclear fuels, this average cost does not include cost components not allowed in the Virginia fuel clause.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
13	S3QCN	QUANTITY OF FUEL CONSUMED	(UNIT)	I8

The total number of units of the fuel consumed for generation in tons, barrels, MCF, etc. For nuclear fuel, enter the gross heat generation in megawatt-days.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
14	S3AHCN	AVERAGE HEAT CONTENT OF FUEL CONSUMED	BTU/(UNIT)	I8

The weighted average heat content of the fuel in BTUs per delivered unit (e.g. BTUs/lb., BTUs/gal., BTUs/MCF, BTUs/assembly, etc.).

SYSTEM FUEL CONSUMPTION DATA (25 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
15	S3TUTC	TOTAL COST OF FUEL CONSUMED	$	I9

The total cost of the fuel consumed for generation in the system in thousands of dollars is reported. This cost does not contain cost components not allowable in the Virginia fuel clause.

FOURTH FUEL TYPE

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
16	S4TYPE	FUEL TYPE		I1

Enter one of the following numbers, for the fuel used to generate the fourth most energy in the system.

1 coal
2 nuclear
3 light fuel oil
4 heavy fuel oil
5 natural gas

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
17	S4BTUC	AVERAGE COST OF FUEL CONSUMED	¢/MMBTU	F7.3

The average cost of primary fuel consumed is the weighted average cost per MMBTU of the fuel consumed during the reporting period. For a fossil fuel, it is the weighted average cost of the fuel consumed during the period. For nuclear fuel, it is the amortization of the burn for all in-core assemblies divided by the gross heat generation in millions of BTUs. For both fossil and nuclear fuels, this average cost does not include cost components not allowed in the Virginia fuel clause.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
18	S4QCN	QUANTITY OF FUEL CONSUMED	(UNIT)	I8

The total number of units of the fuel consumed for generation in tons, barrels, MCF, etc. For nuclear fuel, enter the gross heat generation in megawatt-days.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
19	S4AHCN	AVERAGE HEAT CONTENT OF FUEL CONSUMED	BTU/(UNIT)	I8

The weighted average heat content of the fuel in BTUs per delivered unit (e.g. BTUs/lb., BTUs/gal., BTUs/MCF, BTUs/assembly, etc.).

SYSTEM FUEL CONSUMPTION DATA (25 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
20	S4TUTC	TOTAL COST OF FUEL CONSUMED	$	I9

The total cost of the fuel consumed for generation in the system in thousands of dollars is reported. This cost does not contain cost components not allowable in the Virginia fuel clause.

FIFTH FUEL TYPE

21	S5TYPE	FUEL TYPE		I1

Enter one of the following numbers, for the fuel used to generate the fifth most energy in the system.

1 coal
2 nuclear
3 light fuel oil
4 heavy fuel oil
5 natural gas

22	S5BTUC	AVERAGE COST OF FUEL CONSUMED	¢/MMBTU	F7.3

The average cost of primary fuel consumed is the weighted average cost per MMBTU of the fuel consumed during the reporting period. For a fossil fuel, it is the weighted average cost of the fuel consumed during the period. For nuclear fuel, it is the amortization of the burn for all in-core assemblies divided by the gross heat generation in millions of BTUs. For both fossil and nuclear fuels, this average cost does not include cost components not allowed in the Virginia fuel clause.

23	S5QCN	QUANTITY OF FUEL CONSUMED	(UNIT)	I8

The total number of units of the fuel consumed for generation in tons, barrels, MCF, etc. For nuclear fuel, enter the gross heat generation in megawatt-days.

24	S5AHCN	AVERAGE HEAT CONTENT OF FUEL CONSUMED	BTU/(UNIT)	I8

The weighted average heat content of the fuel in BTUs per delivered unit (e.g. BTUs/lb., BTUs/gal., BTUs/MCF, BTUs/assembly, etc.).

SYSTEM FUEL CONSUMPTION DATA (25 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
25	S5TUTC	TOTAL COST OF FUEL CONSUMED	$	I9
		The total cost of the fuel consumed for generation in the system in thousands of dollars is reported. This cost does not contain cost components not allowable in the Virginia fuel clause.		

SYSTEM DATA (6 Branches)
5th BRANCH: SYSTEM ACCOUNTING ADJUSTMENTS
Record 1 of 1

SYSTEM ACCOUNTING ADJUSTMENTS BY FUEL TYPE (40 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE

ACCOUNTING ADJUSTMENTS OCCURRING DURING THE REPORTING PERIOD FOR FUELS PURCHASED DURING PRIOR PERIODS

FIRST FUEL TYPE

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	S1TYPE	FUEL TYPE		I1
		Enter one of the following numbers, for the fuel used to generate the most energy in the system. 1 coal 2 nuclear 3 light fuel oil 4 heavy fuel oil 5 natural gas		
2	AD1BTU	BTU CONTENT ADJUSTMENT (SYSTEM)	$	I8
		This adjustment contains the total dollar adjustments in system fuel inventory value due to purchase contract price adjustments caused by thermal energy differences. Adjustments to the dollar value of fuel inventory result from the thermal energy, measured in British thermal units, being below or above the amount specified in the purchase contract.		
3	AD1SUF	SULFUR CONTENT ADJUSTMENT (SYSTEM)	$	I9
		This adjustment contains the total dollar change in system fuel inventory value due to purchase contract price adjustments caused by the sulfur content in the fuels differing from the amounts specified in the purchase contracts. The sulfur content of a fuel is the amount of sulfur by weight or volume contained in the fuel.		

SYSTEM ACCOUNTING ADJUSTMENTS BY FUEL TYPE (40 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
4	AD1ASH	ASH CONTENT ADJUSTMENT (SYSTEM)	$	I8
		This adjustment contains the total dollar change in system fuel inventory value due to purchase contract price adjustments caused by the ash content in the fuels differing from the amounts specified in the purchase contracts. The ash content of a fuel is the amount of solid residue left when combustible material is thoroughly burned. The higher the ash content, the higher the disposal cost.		
5	AD1ECL	ESCALATION CLAUSE ADJUSTMENT (SYSTEM)	$	I8
		This adjustment contains the total dollar adjustments to system fuel inventory value due to escalation price increases which occur during the reporting period for purchases in prior periods. Escalation clauses are clauses built into long term fuel contract to provide for price increases linked to certain supplier cost increases. These adjustments occur for fuel purchased and paid for in earlier months.		
6	AD1SET	SUPPLIER SETTLEMENTS (SYSTEM)	$	I8
		This adjustment contains the total dollar adjustments to system fuel inventory values caused by supplier settlements. Supplier settlements are refunds or additional billings for prior expenses where legal action or negotiations have brought settlements of such disputes as contract standards, transportation methods and costs, or weighting errors of the supplier or common carrier.		
7	AD1OTH	OTHER ADJUSTMENTS (SYSTEM)	$	I8
		Other adjustments are any plant inventory value changes, exclusive of those provided for in other classifications, in the book value of the fuel inventories.		
8	AD1TOT	TOTAL (SYSTEM)	$	I8
		This classification is the sum of all fuel inventory adjustments for the fuel type, in dollars, which occur during the reporting period for fuels purchased in prior periods.		

SYSTEM ACCOUNTING ADJUSTMENTS BY FUEL TYPE (40 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		SECOND FUEL TYPE		
9	S2TYPE	FUEL TYPE Enter one of the following numbers, for the fuel used to generate the second most energy in the system. 1 coal 2 nuclear 3 light fuel oil 4 heavy fuel oil 5 natural gas		I1
10	AD2BTU	BTU CONTENT ADJUSTMENT (SYSTEM) This adjustment contains the total dollar adjustments in system fuel inventory value due to purchase contract price adjustments caused by thermal energy differences. Adjustments to the dollar value of fuel inventory result from the thermal energy, measured in British thermal units, being below or above the amount specified in the purchase contract.	$	I8
11	AD2SUF	SULFUR CONTENT ADJUSTMENT (SYSTEM) This adjustment contains the total dollar change in system fuel inventory value due to purchase contract price adjustments caused by the sulfur content in the fuels differing from the amounts specified in the purchase contracts. The sulfur content of a fuel is the amount of sulfur by weight or volume contained in the fuel.	$	I9
12	AD2ASH	ASH CONTENT ADJUSTMENT (SYSTEM) This adjustment contains the total dollar change in system fuel inventory value due to purchase contract price adjustments caused by the ash content in the fuels differing from the amounts specified in the purchase contracts. The ash content of a fuel is the amount of solid residue left when combustible material is thoroughly burned. The higher the ash content, the higher the disposal cost.	$	I8

SYSTEM ACCOUNTING ADJUSTMENTS (40 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
13	AD2ECL	ESCALATION CLAUSE ADJUSTMENT (SYSTEM)	$	I8
		This adjustment contains the total dollar adjustments to system fuel inventory value due to escalation price increases which occur during the reporting period for purchases in prior periods. Escalation clauses are clauses built into long term fuel contract to provide for price increases linked to certain supplier cost increases. These adjustments occur for fuel purchased and paid for in earlier months.		
14	AD2SET	SUPPLIER SETTLEMENTS (SYSTEM)	$	I8
		This adjustment contains the total dollar adjustments to system fuel inventory values caused by supplier settlements. Supplier settlements are refunds or additional billings for prior expenses where legal action or negotiations have brought settlements of such disputes as contract standards, transportation methods and costs, or weighting errors of the supplier or common carrier.		
15	AD2OTH	OTHER ADJUSTMENTS (SYSTEM)	$	I8
		Other adjustments are any plant inventory value changes, exclusive of those provided for in other classifications, in the book value of the fuel inventories.		
16	AD2TOT	TOTAL (SYSTEM)	$	I8
		This classification is the sum of all fuel inventory adjustments for the fuel type, in dollars, which occur during the reporting period for fuels purchased in prior periods.		

THIRD FUEL TYPE

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
17	S3TYPE	FUEL TYPE		I1
		Enter one of the following numbers, for the fuel used to generate the third most energy in the system.		

SYSTEM ACCOUNTING ADJUSTMENTS BY FUEL TYPE (40 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		1 coal 2 nuclear 3 light fuel oil 4 heavy fuel oil 5 natural gas		
18	AD3BTU	BTU CONTENT ADJUSTMENT (SYSTEM) This adjustment contains the total dollar adjustments in system fuel inventory value due to purchase contract price adjustments caused by thermal energy differences. Adjustments to the dollar value of fuel inventory result from the thermal energy, measured in British thermal units, being below or above the amount specified in the purchase contract.	$	I8
19	AD3SUF	SULFUR CONTENT ADJUSTMENT (SYSTEM) This adjustment contains the total dollar change in system fuel inventory value due to purchase contract price adjustments caused by the sulfur content in the fuels differing from the amounts specified in the purchase contracts. The sulfur content of a fuel is the amount of sulfur by weight or volume contained in the fuel.	$	I9
20	AD3ASH	ASH CONTENT ADJUSTMENT (SYSTEM) This adjustment contains the total dollar change in system fuel inventory value due to purchase contract price adjustments caused by the ash content in the fuels differing from the amounts specified in the purchase contracts. The ash content of a fuel is the amount of solid residue left when combustible material is thoroughly burned. The higher the ash content, the higher the disposal cost.	$	I8
21	AD3ECL	ESCALATION CLAUSE ADJUSTMENT (SYSTEM) This adjustment contains the total dollar adjustments to system fuel inventory value due to escalation price increases which occur during the reporting period for purchases in prior periods. Escalation clauses are	$	I8

SYSTEM ACCOUNTING ADJUSTMENTS (40 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		clauses built into long term fuel contract to provide for price increases linked to certain supplier cost increases. These adjustments occur for fuel purchased and paid for in earlier months.		
22	AD3SET	SUPPLIER SETTLEMENTS (SYSTEM)	$	I8
		This adjustment contains the total dollar adjustments to system fuel inventory values caused by supplier settlements. Supplier settlements are refunds or additional billings for prior expenses where legal action or negotiations have brought settlements of such disputes as contract standards, transportation methods and costs, or weighting errors of the supplier or common carrier.		
23	AD3OTH	OTHER ADJUSTMENTS (SYSTEM)	$	I8
		Other adjustments are any plant inventory value changes, exclusive of those provided for in other classifications, in the book value of the fuel inventories.		
24	AD3TOT	TOTAL (SYSTEM)	$	I8
		This classification is the sum of all fuel inventory adjustments for the fuel type, in dollars, which occur during the reporting period for fuels purchased in prior periods.		

FOURTH FUEL TYPE

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
25	S4TYPE	FUEL TYPE		I1
		Enter one of the following numbers, for the fuel used to generate the fourth most energy in the system. 1 coal 2 nuclear 3 light fuel oil 4 heavy fuel oil 5 natural gas		

SYSTEM ACCOUNTING ADJUSTMENTS BY FUEL TYPE (40 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
26	AD4BTU	BTU CONTENT ADJUSTMENT (SYSTEM)	$	I8
		This adjustment contains the total dollar adjustments in system fuel inventory value due to purchase contract price adjustments caused by thermal energy differences. Adjustments to the dollar value of fuel inventory result from the thermal energy, measured in British thermal units, being below or above the amount specified in the purchase contract.		
27	AD4SUF	SULFUR CONTENT ADJUSTMENT (SYSTEM)	$	I9
		This adjustment contains the total dollar change in system fuel inventory value due to purchase contract price adjustments caused by the sulfur content in the fuels differing from the amounts specified in the purchase contracts. The sulfur content of a fuel is the amount of sulfur by weight or volume contained in the fuel.		
28	AD4ASH	ASH CONTENT ADJUSTMENT (SYSTEM)	$	I8
		This adjustment contains the total dollar change in system fuel inventory value due to purchase contract price adjustments caused by the ash content in the fuels differing from the amounts specified in the purchase contracts. The ash content of a fuel is the amount of solid residue left when combustible material is thoroughly burned. The higher the ash content, the higher the disposal cost.		
29	AD4ECL	ESCALATION CLAUSE ADJUSTMENT (SYSTEM)	$	I8
		This adjustment contains the total dollar adjustments to system fuel inventory value due to escalation price increases which occur during the reporting period for purchases in prior periods. Escalation clauses are clauses built into long term fuel contract to provide for price increases linked to certain supplier cost increases. These adjustments occur for fuel purchased and paid for in earlier months.		

SYSTEM ACCOUNTING ADJUSTMENTS (40 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
30	AD4SET	SUPPLIER SETTLEMENTS (SYSTEM)	$	I8

This adjustment contains the total dollar adjustments to system fuel inventory values caused by supplier settlements. Supplier settlements are refunds or additional billings for prior expenses where legal action or negotiations have brought settlements of such disputes as contract standards, transportation methods and costs, or weighting errors of the supplier or common carrier.

31	AD4OTH	OTHER ADJUSTMENTS (SYSTEM)	$	I8

Other adjustments are any plant inventory value changes, exclusive of those provided for in other classifications, in the book value of the fuel inventories.

32	AD4TOT	TOTAL (SYSTEM)	$	I8

This classification is the sum of all fuel inventory adjustments for the fuel type, in dollars, which occur during the reporting period for fuels purchased in prior periods.

FIFTH FUEL TYPE

33	S5TYPE	FUEL TYPE		I1

Enter one of the following numbers, for the fuel used to generate the fifth most energy in the system.

1 coal
2 nuclear
3 light fuel oil
4 heavy fuel oil
5 natural gas

34	AD5BTU	BTU CONTENT ADJUSTMENT (SYSTEM)	$	I8

This adjustment contains the total dollar adjustments in system fuel inventory value due to purchase contract price adjustments caused by thermal energy differences. Adjustments to the dollar value of fuel

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		inventory result from the thermal energy, measured in British thermal units, being below or above the amount specified in the purchase contract.		
35	AD5SUF	SULFUR CONTENT ADJUSTMENT (SYSTEM)	$	I9
		This adjustment contains the total dollar change in system fuel inventory value due to purchase contract price adjustments caused by the sulfur content in the fuels differing from the amounts specified in the purchase contracts. The sulfur content of a fuel is the amount of sulfur by weight or volume contained in the fuel.		
36	AD5ASH	ASH CONTENT ADJUSTMENT (SYSTEM)	$	I8
		This adjustment contains the total dollar change in system fuel inventory value due to purchase contract price adjustments caused by the ash content in the fuels differing from the amounts specified in the purchase contracts. The ash content of a fuel is the amount of solid residue left when combustible material is thoroughly burned. The higher the ash content, the higher the disposal cost.		
37	AD5ECL	ESCALATION CLAUSE ADJUSTMENT (SYSTEM)	$	I8
		This adjustment contains the total dollar adjustments to system fuel inventory value due to escalation price increases which occur during the reporting period for purchases in prior periods. Escalation clauses are clauses built into long term fuel contract to provide for price increases linked to certain supplier cost increases. These adjustments occur for fuel purchased and paid for in earlier months.		
38	AD5SET	SUPPLIER SETTLEMENTS (SYSTEM)	$	I8
		This adjustment contains the total dollar adjustments to system fuel inventory values caused by supplier settlements. Supplier settlements are refunds or additional billings for prior expenses where legal		

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		action or negotiations have brought settlements of such disputes as contract standards, transportation methods and costs, or weighting errors of the supplier or common carrier.		
39	AD5OTH	OTHER ADJUSTMENTS (SYSTEM)	$	I8
		Other adjustments are any plant inventory value changes, exclusive of those provided for in other classifications, in the book value of the fuel inventories.		
40	AD5TOT	TOTAL (SYSTEM)	$	I8
		This classification is the sum of all fuel inventory adjustments for the fuel type, in dollars, which occur during the reporting period for fuels purchased in prior periods.		

TOTAL FUEL PURCHASES (8 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	TCCOAL	COAL	$	I9
		Cost, in dollars, of all types of coal (lignite, bituminous, anthracite, and petroleum coke) purchased. The cost includes only those costs which are allowable under the Virginia fuel clause.		
2	TCNUYE	NUCLEAR - YELLOWCAKE	$	I9
		Cost, in dollars, of yellowcake (uranium ore concentrate - U_3O_8) purchased. The cost includes only those costs which are allowable under the Virginia fuel clause.		
3	TCNUIP	NUCLEAR - IN PROCESS	$	I9
		Cost, in dollars, of nuclear fuel purchased at one of the steps of processing between the initial ore (yellowcake) and the completed fuel assembly. The various stages of completion at which nuclear fuel might be purchased are refining, enrichment, conversion, and fabrication. The cost includes only those costs which are allowable under the Virginia fuel clause.		
4	TCNUFA	NUCLEAR FUEL ASSEMBLIES	$	I9
		Cost, in dollars, of completed nuclear fuel assemblies purchased. The cost includes only those costs which are allowable under the Virginia fuel clause.		
5	TCFOL	LIGHT OIL	$	I9
		Cost, in dollars, of light oil (low specific gravity) purchased. Light oil includes fuel oil no. 2, kerosene, diesel oil, jet fuel, rerefined motor oil, and liquefied petroleum gas. The cost includes only those costs which are allowable under the Virginia fuel clause.		

TOTAL FUEL PURCHASES (8 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
6	TCFOH	HEAVY OIL	$	I9
		Cost, in dollars, of heavy oil (residual oil) purchased. Heavy oil includes fuel oils nos. 4, 5, and 6, crude, and topped crude. The cost includes only those costs which are allowable under the Virginia fuel clause.		
7	TCNGAS	NATURAL GAS	$	I9
		Cost, in dollars, of natural gas purchased. Natural gas includes natural gas, blast furnace gas, coke oven gas, and refinery gas. The cost includes only those costs which are allowable under the Virginia fuel clause.		
8	TCTOTL	TOTAL COST	$	I9
		Total cost is the sum of the above fuel costs. The total cost is the total of all fuel costs (allowable by the Virginia fuel clause) for the whole company, <u>not just the Virginia jurisdiction</u>.		

TOTAL COAL PURCHASES (20 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE THERMAL ENERGY COSTS		
1	CAECT1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the coal is less than or equal to 1% of the total weight of the coal as reported on FERC Form 423. The total FOB mine cost (in cents) of all of the coal purchased within this sulfur range is divided by the number of millions of BTUs in the coal purchased to derive the average thermal energy cost.		
2	CAECT2	FOR 1.01% TO 2% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal as reported on FERC Form 423. The total FOB mine cost (in cents) of all of the coal purchased within this sulfur range is divided by the number of millions of BTUs in the coal purchased to derive the average thermal energy cost.		
3	CAECT3	FOR GREATER THAN 2% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the coal is greater than 2% of the total weight of the coal as reported on FERC Form 423. The total FOB mine cost (in cents) of all of the coal purchased within this sulfur range is divided by the number of millions of BTUs in the coal purchased to derive the average thermal energy cost.		
4	CAECTA	AVERAGE FOR ALL COAL	¢/MMBTU	F7.3
		The average FOB mine cost (in cents) of coal consumed per million BTUs is the weighted average of the above. It is the total FOB mine cost of the coal purchased, in cents, divided by the total thermal energy input, in millions of BTUs, of the coal purchased.		

TOTAL COAL PURCHASES (20 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE TRANSPORTATION COSTS		
5	CATCT1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The allowable transportation costs (in cents) from the mine of all coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average transportation cost.		
6	CATCT2	FOR 1.01% TO 2% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The allowable transportation costs (in cents) from the mine of all coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average transportation cost.		
7	CATCT3	FOR GREATER THAN 2% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the coal is greater than 2% of the total weight of the coal. The allowable transportation costs (in cents) from the mine of all coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average transportation cost.		
8	CATCTA	AVERAGE FOR ALL COAL	¢/MMBTU	F7.3
		The average transportation cost (in cents) of coal consumed per million BTUs is the weighted average of the above. It is the allowable transportation costs of coal purchased, in cents, divided by the total thermal energy input, in millions of BTUs, of the coal purchased.		

TOTAL COAL PURCHASES (20 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE HEAT CONTENT		
9	CAHCN1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT	BTU/LB	I5
		The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The average heat content is the total BTUs in coal purchased within this sulfur range divided by the total number of pounds of coal purchased within this range.		
10	CAHCN2	FOR 1.01% TO 2% SULFUR CONTENT	BTU/LB	I5
		The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The average heat content is the total BTUs in coal purchased divided by the total number of pounds of coal purchased within the sulfur range.		
11	CAHCN3	FOR GREATER THAN 2% SULFUR CONTENT	BTU/LB	I5
		The sulfur content of the coal is greater than 2% of the total weight of the coal. The average heat content is the total BTUs in coal purchased divided by the total number of pounds of coal purchased within the sulfur range.		
12	CAHCNA	AVERAGE FOR ALL COAL	BTU/LB	I5
		The average heat content is the weighted average of the above. It is the total of BTUs in coal purchased divided by the total number of pounds of coal purchased.		
		QUANTITY OF COAL PURCHASED		
13	CTFCN1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT	TONS	I8
		The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The coal quantity is the total number of tons (2,000 lbs. per ton) of coal purchased within the sulfur range.		

TOTAL COAL PURCHASES (20 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
14	CTFCN2	FOR 1.01% TO 2% SULFUR CONTENT The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The coal quantity is the total number of tons (2,000 lbs. per ton) of coal purchased within the sulfur range.	TONS	I8
15	CTFCN3	FOR GREATER THAN 2% SULFUR CONTENT The sulfur content of the coal is greater than 2% of the total weight of the coal. The coal quantity is the total number of tons (2,000 lbs. per ton) of coal purchased within the sulfur range.	TONS	I8
16	CTFCNT	TOTAL COAL PURCHASED The total coal purchased is the total quantity of coal, measured in tons (2,000 lbs. per ton).	TONS	I8

TOTAL COST OF COAL PURCHASED, FOB PLANT

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
17	CTTCT1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The total cost of coal is the invoiced coal costs in dollars for coal within the sulfur range.	$	I9
18	CTTCT2	FOR 1.01% TO 2% SULFUR CONTENT The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The total cost of coal is the invoiced coal costs in dollars for coal within the sulfur range.	$	I9
19	CTTCT3	FOR GREATER THAN 2% SULFUR CONTENT The sulfur content of the coal is greater than 2% of the total weight of the coal. The total cost of coal is the invoiced coal costs in dollars for coal within the sulfur range.	$	I9

TOTAL COAL PURCHASES (20 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
20	CTTCTT	TOTAL COSTS OF COAL	$	I9
		The total cost of coal is the total invoiced dollar costs of coal purchased, FOB plant.		

SPOT COAL PURCHASES (20 elements)

The spot market for coal is a market where coal is purchased directly from the mine for immediate delivery or under contract for a duration of less than one year. This classification is for all coal which was purchased on the spot market.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE THERMAL ENERGY COSTS		
1	CSECT1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The total FOB mine cost (in cents) of all of the coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average thermal energy cost.	¢/MMBTU	F7.3
2	CSECT2	FOR 1.01% TO 2% SULFUR CONTENT The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The total FOB mine cost (in cents) of all of the coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average thermal energy cost.	¢/MMBTU	F7.3
3	CSECT3	FOR GREATER THAN 2% SULFUR CONTENT The sulfur content of the coal is greater than 2% of the total weight of the coal. The total FOB mine cost (in cents) of all of the coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average thermal energy cost.	¢/MMBTU	F7.3
4	CSECTA	AVERAGE FOR ALL COAL The average FOB mine cost (in cents) of coal consumed per million BTUs is the weighted average of the above. It is the total FOB mine cost of the coal purchased, in cents, divided by the total thermal energy input, in millions of BTUs, of the coal purchased.	¢/MMBTU	F7.3

SPOT COAL PURCHASES (20 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE TRANSPORTATION COSTS		
5	CSTCT1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The allowable transportation costs (in cents) from the mine of all coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average transportation cost.		
6	CSTCT2	FOR 1.01% TO 2% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The allowable transportation costs (in cents) from the mine of all coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average transportation cost.		
7	CSTCT3	FOR GREATER THAN 2% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the coal is greater than 2% of the total weight of the coal. The allowable transportation costs (in cents) from the mine of all coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average transportation cost.		
8	CSTCTA	AVERAGE FOR ALL COAL	¢/MMBTU	F7.3
		The average transportation cost (in cents) of coal consumed per million BTUs is the weighted average of the above. It is the allowable transportation costs of coal purchased, in cents, divided by the total thermal energy input, in millions of BTUs, of the coal purchased.		

SPOT COAL PURCHASES (20 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE

AVERAGE HEAT CONTENT

9	CSHCN1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT	BTU/LB	I5

The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The average heat content is the total BTUs in coal purchased within this sulfur range divided by the total number of pounds of coal purchased within this range.

10	CSHCN2	FOR 1.01% TO 2% SULFUR CONTENT	BTU/LB	I5

The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The average heat content is the total BTUs in coal purchased divided by the total number of pounds of coal purchased within the sulfur range.

11	CSHCN3	FOR GREATER THAN 2% SULFUR CONTENT	BTU/LB	I5

The sulfur content of the coal is greater than 2% of the total weight of the coal. The average heat content is the total BTUs in coal purchased divided by the total number of pounds of coal purchased within the sulfur range.

12	CSHCNA	AVERAGE FOR ALL COAL	BTU/LB	I5

The average heat content is the weighted average of the above. It is the total of BTUs in coal purchased divided by the total number of pounds of coal purchased.

QUANTITY OF COAL PURCHASED

13	CSFCN1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT	TONS	I8

The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The coal quantity is the total number of tons (2,000 lbs. per ton) of coal purchased within the sulfur range.

SPOT COAL PURCHASES (20 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
14	CSFCN2	FOR 1.01% TO 2% SULFUR CONTENT	TONS	I8
		The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The coal quantity is the total number of tons (2,000 lbs. per ton) of coal purchased within the sulfur range.		
15	CSFCN3	FOR GREATER THAN 2% SULFUR CONTENT	TONS	I8
		The sulfur content of the coal is greater than 2% of the total weight of the coal. The coal quantity is the total number of tons (2,000 lbs. per ton) of coal purchased within the sulfur range.		
16	CSFCNT	TOTAL COAL PURCHASED	TONS	I8
		The total coal purchased is the total quantity of coal, measured in tons (2,000 lbs. per ton).		

TOTAL COST OF COAL PURCHASED, FOB PLANT

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
17	CSTCT1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT	$	I9
		The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The total cost of coal is the invoiced coal costs in dollars for coal within the sulfur range.		
18	CSTCT2	FOR 1.01% TO 2% SULFUR CONTENT	$	I9
		The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The total cost of coal is the invoiced coal costs in dollars for coal within the sulfur range.		
19	CSTCT3	FOR GREATER THAN 2% SULFUR CONTENT	$	I9
		The sulfur content of the coal is greater than 2% of the total weight of the coal. The total cost of coal is the invoiced coal costs in dollars for coal within the sulfur range.		

SPOT COAL PURCHASES (20 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
20	CSTCTT	TOTAL COSTS OF COAL	$	I9
		The total cost of coal is the total invoiced dollar costs of coal purchased, FOB plant.		

BROKER COAL PURCHASES (20 elements)

The brokerage system of purchasing coal is an intermediary system where the broker is supposed to shop around for the best price of coal, instead of depending upon just a few suppliers. These purchase agreements are short term for less than one year. This classification is for all coal which was purchased through a broker.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE THERMAL ENERGY COSTS		
1	CBECT1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The total FOB mine cost (in cents) of all of the coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average thermal energy cost.	¢/MMBTU	F7.3
2	CBECT2	FOR 1.01% TO 2% SULFUR CONTENT The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The total FOB mine cost (in cents) of all of the coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average thermal energy cost.	¢/MMBTU	F7.3
3	CBECT3	FOR GREATER THAN 2% SULFUR CONTENT The sulfur content of the coal is greater than 2% of the total weight of the coal. The total FOB mine cost (in cents) of all of the coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average thermal energy cost.	¢/MMBTU	F7.3
4	CBECTA	AVERAGE FOR ALL COAL The average FOB mine cost (in cents) of coal consumed per million BTUs is the weighted average of the above. It is the total FOB mine cost of the coal purchased, in cents, divided by the total thermal energy input, in millions of BTUs, of the coal purchased.	¢/MMBTU	F7.3

BROKER COAL PURCHASES (20 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE TRANSPORTATION COSTS		
5	CBTCT1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The allowable transportation costs (in cents) from the mine of all coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average transportation cost.		
6	CBTCT2	FOR 1.01% TO 2% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The allowable transportation costs (in cents) from the mine of all coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average transportation cost.		
7	CBTCT3	FOR GREATER THAN 2% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the coal is greater than 2% of the total weight of the coal. The allowable transportation costs (in cents) from the mine of all coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average transportation cost.		
8	CBTCTA	AVERAGE FOR ALL COAL	¢/MMBTU	F7.3
		The average transportation cost (in cents) of coal consumed per million BTUs is the weighted average of the above. It is the allowable transportation costs of coal purchased, in cents, divided by the total thermal energy input, in millions of BTUs, of the coal purchased.		

BROKER COAL PURCHASES (20 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE HEAT CONTENT		
9	CBHCN1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT	BTU/LB	I5
		The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The average heat content is the total BTUs in coal purchased within this sulfur range divided by the total number of pounds of coal purchased within this range.		
10	CBHCN2	FOR 1.01% TO 2% SULFUR CONTENT	BTU/LB	I5
		The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The average heat content is the total BTUs in coal purchased divided by the total number of pounds of coal purchased within the sulfur range.		
11	CBHCN3	FOR GREATER THAN 2% SULFUR CONTENT	BTU/LB	I5
		The sulfur content of the coal is greater than 2% of the total weight of the coal. The average heat content is the total BTUs in coal purchased divided by the total number of pounds of coal purchased within the sulfur range.		
12	CBHCNA	AVERAGE FOR ALL COAL	BTU/LB	I5
		The average heat content is the weighted average of the above. It is the total of BTUs in coal purchased divided by the total number of pounds of coal purchased.		
		QUANTITY OF COAL PURCHASED		
13	CBFCN1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT	TONS	I8
		The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The coal quantity is the total number of tons (2,000 lbs. per ton) of coal purchased within the sulfur range.		

BROKER COAL PURCHASES (20 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
14	CBFCN2	FOR 1.01% TO 2% SULFUR CONTENT	TONS	I8
		The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The coal quantity is the total number of tons (2,000 lbs. per ton) of coal purchased within the sulfur range.		
15	CBFCN3	FOR GREATER THAN 2% SULFUR CONTENT	TONS	I8
		The sulfur content of the coal is greater than 2% of the total weight of the coal. The coal quantity is the total number of tons (2,000 lbs. per ton) of coal purchased within the sulfur range.		
16	CBFCNT	TOTAL COAL PURCHASED	TONS	I8
		The total coal purchased is the total quantity of coal, measured in tons (2,000 lbs. per ton).		
		TOTAL COST OF COAL PURCHASED, FOB PLANT		
17	CBTCT1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT	$	I9
		The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The total cost of coal is the invoiced coal costs in dollars for coal within the sulfur range.		
18	CBTCT2	FOR 1.01% TO 2% SULFUR CONTENT	$	I9
		The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The total cost of coal is the invoiced coal costs in dollars for coal within the sulfur range.		
19	CBTCT3	FOR GREATER THAN 2% SULFUR CONTENT	$	I9
		The sulfur content of the coal is greater than 2% of the total weight of the coal. The total cost of coal is the invoiced coal costs in dollars for coal within the sulfur range.		

BROKER COAL PURCHASES (20 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
20	CBTCTT	TOTAL COSTS OF COAL	$	I9
		The total cost of coal is the total invoiced dollar costs of coal purchased, FOB plant.		

AFFILIATE COAL PURCHASES (20 elements)

Long term affiliate purchases are purchases under long term contracts (one year or longer) made with coal mining companies that are affiliates of the electric utility. This classification is for all coal which was purchased from affiliate companies on a long term basis.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE THERMAL ENERGY COSTS		
1	CLECT1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The total FOB mine cost (in cents) of all of the coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average thermal energy cost.		
2	CLECT2	FOR 1.01% TO 2% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The total FOB mine cost (in cents) of all of the coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average thermal energy cost.		
3	CLECT3	FOR GREATER THAN 2% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the coal is greater than 2% of the total weight of the coal. The total FOB mine cost (in cents) of all of the coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average thermal energy cost.		
4	CLECTA	AVERAGE FOR ALL COAL	¢/MMBTU	F7.3
		The average FOB mine cost (in cents) of coal consumed per million BTUs is the weighted average of the above. It is the total FOB mine cost of the coal purchased, in cents, divided by the total thermal energy input, in millions of BTUs, of the coal purchased.		

AFFILIATE COAL PURCHASES (20 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE TRANSPORTATION COSTS		
5	CLTCT1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The allowable transportation costs (in cents) from the mine of all coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average transportation cost.		
6	CLTCT2	FOR 1.01% TO 2% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The allowable transportation costs (in cents) from the mine of all coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average transportation cost.		
7	CLTCT3	FOR GREATER THAN 2% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the coal is greater than 2% of the total weight of the coal. The allowable transportation costs (in cents) from the mine of all coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average transportation cost.		
8	CLTCTA	AVERAGE FOR ALL COAL	¢/MMBTU	F7.3
		The average transportation cost (in cents) of coal consumed per million BTUs is the weighted average of the above. It is the allowable transportation costs of coal purchased, in cents, divided by the total thermal energy input, in millions of BTUs, of the coal purchased.		

AFFILIATE COAL PURCHASES (20 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE HEAT CONTENT		
9	CLHCN1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The average heat content is the total BTUs in coal purchased within this sulfur range divided by the total number of pounds of coal purchased within this range.	BTU/LB	I5
10	CLHCN2	FOR 1.01% TO 2% SULFUR CONTENT The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The average heat content is the total BTUs in coal purchased divided by the total number of pounds of coal purchased within the sulfur range.	BTU/LB	I5
11	CLHCN3	FOR GREATER THAN 2% SULFUR CONTENT The sulfur content of the coal is greater than 2% of the total weight of the coal. The average heat content is the total BTUs in coal purchased divided by the total number of pounds of coal purchased within the sulfur range.	BTU/LB	I5
12	CLHCNA	AVERAGE FOR ALL COAL The average heat content is the weighted average of the above. It is the total of BTUs in coal purchased divided by the total number of pounds of coal purchased.	BTU/LB	I5
		QUANTITY OF COAL PURCHASED		
13	CLFCN1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The coal quantity is the total number of tons (2,000 lbs. per ton) of coal purchased within the sulfur range.	TONS	I8

AFFILIATE COAL PURCHASES (20 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
14	CLFCN2	FOR 1.01% TO 2% SULFUR CONTENT	TONS	I8
		The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The coal quantity is the total number of tons (2,000 lbs. per ton) of coal purchased within the sulfur range.		
15	CLFCN3	FOR GREATER THAN 2% SULFUR CONTENT	TONS	I8
		The sulfur content of the coal is greater than 2% of the total weight of the coal. The coal quantity is the total number of tons (2,000 lbs. per ton) of coal purchased within the sulfur range.		
16	CLFCNT	TOTAL COAL PURCHASED	TONS	I8
		The total coal purchased is the total quantity of coal, measured in tons (2,000 lbs. per ton).		
		TOTAL COST OF COAL PURCHASED, FOB PLANT		
17	CLTCT1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT	$	I9
		The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The total cost of coal is the invoiced coal costs in dollars for coal within the sulfur range.		
18	CLTCT2	FOR 1.01% TO 2% SULFUR CONTENT	$	I9
		The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The total cost of coal is the invoiced coal costs in dollars for coal within the sulfur range.		
19	CLTCT3	FOR GREATER THAN 2% SULFUR CONTENT	$	I9
		The sulfur content of the coal is greater than 2% of the total weight of the coal. The total cost of coal is the invoiced coal costs in dollars for coal within the sulfur range.		

AFFILIATE COAL PURCHASES (20 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
20	CLTCTT	TOTAL COSTS OF COAL	$	I9
		The total cost of coal is the total invoiced dollar costs of coal purchased, FOB plant.		

NON-AFFILIATE COAL PURCHASES (20 elements)

Long term non-affiliate purchases are purchases under long term contracts (one year or longer) from independent (unrelated financially and legally) coal companies. This classification is for all coal purchased from non-affiliate companies on a long term basis.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE THERMAL ENERGY COSTS		
1	CNECT1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The total FOB mine cost (in cents) of all of the coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average thermal energy cost.	¢/MMBTU	F7.3
2	CNECT2	FOR 1.01% TO 2% SULFUR CONTENT The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The total FOB mine cost (in cents) of all of the coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average thermal energy cost.	¢/MMBTU	F7.3
3	CNECT3	FOR GREATER THAN 2% SULFUR CONTENT The sulfur content of the coal is greater than 2% of the total weight of the coal. The total FOB mine cost (in cents) of all of the coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average thermal energy cost.	¢/MMBTU	F7.3
4	CNECTA	AVERAGE FOR ALL COAL The average FOB mine cost (in cents) of coal consumed per million BTUs is the weighted average of the above. It is the total FOB mine cost of the coal purchased, in cents, divided by the total thermal energy input, in millions of BTUs, of the coal purchased.	¢/MMBTU	F7.3

NON-AFFILIATE COAL PURCHASES (20 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE

AVERAGE TRANSPORTATION COSTS

5	CNTCT1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT	¢/MMBTU	F7.3

The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The allowable transportation costs (in cents) from the mine of all coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average transportation cost.

6	CNTCT2	FOR 1.01% TO 2% SULFUR CONTENT	¢/MMBTU	F7.3

The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The allowable transportation costs (in cents) from the mine of all coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average transportation cost.

7	CNTCT3	FOR GREATER THAN 2% SULFUR CONTENT	¢/MMBTU	F7.3

The sulfur content of the coal is greater than 2% of the total weight of the coal. The allowable transportation costs (in cents) from the mine of all coal purchased within this sulfur range divided by the number of millions of BTUs in the coal purchased equals the average transportation cost.

8	CNTCTA	AVERAGE FOR ALL COAL	¢/MMBTU	F7.3

The average transportation cost (in cents) of coal consumed per million BTUs is the weighted average of the above. It is the allowable transportation costs of coal purchased, in cents, divided by the total thermal energy input, in millions of BTUs, of the coal purchased.

NON-AFFILIATE COAL PURCHASES (20 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE HEAT CONTENT		
9	CNHCN1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The average heat content is the total BTUs in coal purchased within this sulfur range divided by the total number of pounds of coal purchased within this range.	BTU/LB	I5
10	CNHCN2	FOR 1.01% TO 2% SULFUR CONTENT The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The average heat content is the total BTUs in coal purchased divided by the total number of pounds of coal purchased within the sulfur range.	BTU/LB	I5
11	CNHCN3	FOR GREATER THAN 2% SULFUR CONTENT The sulfur content of the coal is greater than 2% of the total weight of the coal. The average heat content is the total BTUs in coal purchased divided by the total number of pounds of coal purchased within the sulfur range.	BTU/LB	I5
12	CNHCNA	AVERAGE FOR ALL COAL The average heat content is the weighted average of the above. It is the total of BTUs in coal purchased divided by the total number of pounds of coal purchased.	BTU/LB	I5
		QUANTITY OF COAL PURCHASED		
13	CNFCN1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The coal quantity is the total number of tons (2,000 lbs. per ton) of coal purchased within the sulfur range.	TONS	I8

NON-AFFILIATE COAL PURCHASES (20 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
14	CNFCN2	FOR 1.01% TO 2% SULFUR CONTENT	TONS	I8
		The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The coal quantity is the total number of tons (2,000 lbs. per ton) of coal purchased within the sulfur range.		
15	CNFCN3	FOR GREATER THAN 2% SULFUR CONTENT	TONS	I8
		The sulfur content of the coal is greater than 2% of the total weight of the coal. The coal quantity is the total number of tons (2,000 lbs. per ton) of coal purchased within the sulfur range.		
16	CNFCNT	TOTAL COAL PURCHASED	TONS	I8
		The total coal purchased is the total quantity of coal, measured in tons (2,000 lbs. per ton).		

TOTAL COST OF COAL PURCHASED, FOB PLANT

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
17	CNTCT1	FOR LESS THAN OR EQUAL TO 1% SULFUR CONTENT	$	I9
		The sulfur content of the coal is less than or equal to 1% of the total weight of the coal. The total cost of coal is the invoiced coal costs in dollars for coal within the sulfur range.		
18	CNTCT2	FOR 1.01% TO 2% SULFUR CONTENT	$	I9
		The sulfur content of the coal is between 1.01% to 2% of the total weight of the coal. The total cost of coal is the invoiced coal costs in dollars for coal within the sulfur range.		
19	CNTCT3	FOR GREATER THAN 2% SULFUR CONTENT	$	I9
		The sulfur content of the coal is greater than 2% of the total weight of the coal. The total cost of coal is the invoiced coal costs in dollars for coal within the sulfur range.		

NON-AFFILIATE COAL PURCHASES (20 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
20	CNTCTT	TOTAL COSTS OF COAL	$	I9
		The total cost of coal is the total invoiced dollar costs of coal purchased, FOB plant.		

TOTAL OIL PURCHASES (12 elements)

Total company wide purchase of fuel oils #2, #4, and #6 and other.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE THERMAL ENERGY COSTS		
1	OILEC1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The total cost in cents of the oil (including allowable transportation costs) purchased within this sulfur range divided by the number of millions of BTUs in this oil equals the average thermal energy cost.		
2	OILEC2	FOR GREATER THAN 1.5% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The total cost in cents of the oil (including allowable transportation costs) purchased within this sulfur range divided by the number of millions of BTUs in this oil equals the average thermal energy cost.		
3	OILECA	AVERAGE FOR ALL FUEL OIL	¢/MMBTU	F7.3
		The total cost of all fuel oil purchased per million BTUs is the weighted average of the above. It is the total fuel oil costs in cents (including allowable transportation costs) divided by the total thermal energy input, in millions of BTUs.		

TOTAL OIL PURCHASES (12 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE HEAT CONTENT		
4	OILHN1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The average heat content is the total BTUs in the fuel oil purchased divided by the total number of gallons of fuel oil within this sulfur range.	BTU/GAL	I6
5	OILHN2	FOR GREATER THAN 1.5% SULFUR CONTENT The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The average heat content is the total BTUs in the fuel oil purchased divided by the total number of gallons of fuel oil within this sulfur range.	BTU/GAL	I6
6	OILHNA	AVERAGE FOR ALL FUEL OIL The average heat content of all the fuel oil purchased is the weighted average of the above. It is the total of BTUs in fuel oil purchased divided by the total number of gallons of fuel oil.	BTU/GAL	I6
		QUANTITY OF FUEL OIL PURCHASED		
7	OILFN1	LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The oil quantity is the total number of barrels (42 gallons) of oil consumed in power generation, within the sulfur range.	BLS	I8
8	OILFN2	FOR GREATER THAN 1.5% SULFUR CONTENT The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The oil quantity is the total number of barrels (42 gallons) of oil consumed in power generation, within the sulfur range.	BLS	I8

TOTAL OIL PURCHASES (12 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
9	OILFNT	TOTAL FUEL OIL CONSUMED	BLS	I8
		The total fuel oil quantity is the volume of oil, measured in barrels (42 gallons per barrel).		
		TOTAL COST OF FUEL OIL		
10	OILFC1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	$	I9
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The total cost of the fuel oil is the total allowable oil costs in dollars of the oil purchased.		
11	OILFC2	FOR GREATER THAN 1.5% SULFUR CONTENT	$	I9
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The total cost of the fuel oil is the total allowable oil costs in dollars of the oil purchased.		
12	OILFCT	TOTAL COST OF FUEL OIL	$	I9
		The total cost of fuel oil is the total allowable dollar costs of fuel oil purchased.		

TOTAL LIGHT OIL PURCHASES (12 elements)

The total company wide purchase of light oil, including Fuel Oil No. 2 (furnace oil), kerosene, diesel oil, jet fuel, refined motor oil, and liquefied petroleum gas.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE THERMAL ENERGY COSTS		
1	02AEC1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The total cost in cents of the oil (including allowable transportation costs) purchased within this sulfur range divided by the number of millions of BTUs in this oil equals the average thermal energy cost.	¢/MMBTU	F7.3
2	02AEC2	FOR GREATER THAN 1.5% SULFUR CONTENT The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The total cost in cents of the oil (including allowable transportation costs) purchased within this sulfur range divided by the number of millions of BTUs in this oil equals the average thermal energy cost.	¢/MMBTU	F7.3
3	02AECA	AVERAGE FOR ALL FUEL OIL The total cost of all fuel oil purchased per million BTUs is the weighted average of the above. It is the total fuel oil costs in cents (including allowable transportation costs) divided by the total thermal energy input, in millions of BTUs.	¢/MMBTU	F7.3

TOTAL LIGHT OIL PURCHASES (12 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE HEAT CONTENT		
4	02AHN1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	BTU/GAL	I6
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The average heat content is the total BTUs in the fuel oil purchased divided by the total number of gallons of fuel oil within this sulfur range.		
5	02AHN2	FOR GREATER THAN 1.5% SULFUR CONTENT	BTU/GAL	I6
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The average heat content is the total BTUs in the fuel oil purchased divided by the total number of gallons of fuel oil within this sulfur range.		
6	02AHNA	AVERAGE FOR ALL FUEL OIL	BTU/GAL	I6
		The average heat content of all the fuel oil purchased is the weighted average of the above. It is the total of BTUs in fuel oil purchased divided by the total number of gallons of fuel oil.		
		QUANTITY OF FUEL OIL PURCHASED		
7	02AFN1	LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	BLS	I8
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The oil quantity is the total number of barrels (42 gallons) of oil consumed in power generation, within the sulfur range.		
8	02AFN2	FOR GREATER THAN 1.5% SULFUR CONTENT	BLS	I8
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The oil quantity is the total number of barrels (42 gallons) of oil consumed in power generation, within the sulfur range.		

TOTAL LIGHT OIL PURCHASES (12 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
9	02AFNT	TOTAL FUEL OIL CONSUMED	BLS	I8
		The total fuel oil quantity is the volume of oil, measured in barrels (42 gallons per barrel).		
		TOTAL COST OF FUEL OIL		
10	02AFC1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	$	I9
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The total cost of the fuel oil is the total allowable oil costs in dollars of the oil purchased.		
11	02AFC2	FOR GREATER THAN 1.5% SULFUR CONTENT	$	I9
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The total cost of the fuel oil is the total allowable oil costs in dollars of the oil purchased.		
12	02AFCT	TOTAL COST OF FUEL OIL	$	I9
		The total cost of fuel oil is the total allowable dollar costs of fuel oil purchased.		

SYSTEM DATA (6 Branches)
6th BRANCH: SYSTEM FUEL PURCHASE DATA
Record 9 of 17

SPOT LIGHT OIL PURCHASES (12 elements)

The total company wide Light Fuel Oil which was purchased on the spot market. The spot market for oil is a market where oil is purchased from the supplier for immediate delivery or under contract for a duration of less than one year.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE THERMAL ENERGY COSTS		
1	O2SEC1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The total cost in cents of the oil (including allowable transportation costs) purchased within this sulfur range divided by the number of millions of BTUs in this oil equals the average thermal energy cost.		
2	O2SEC2	FOR GREATER THAN 1.5% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The total cost in cents of the oil (including allowable transportation costs) purchased within this sulfur range divided by the number of millions of BTUs in this oil equals the average thermal energy cost.		
3	O2SECA	AVERAGE FOR ALL FUEL OIL	¢/MMBTU	F7.3
		The total cost of all fuel oil purchased per million BTUs is the weighted average of the above. It is the total fuel oil costs in cents (including allowable transportation costs) divided by the total thermal energy input, in millions of BTUs.		

SPOT LIGHT OIL PURCHASES (12 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE HEAT CONTENT		
4	02SHN1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The average heat content is the total BTUs in the fuel oil purchased divided by the total number of gallons of fuel oil within this sulfur range.	BTU/GAL	I6
5	02SHN2	FOR GREATER THAN 1.5% SULFUR CONTENT The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The average heat content is the total BTUs in the fuel oil purchased divided by the total number of gallons of fuel oil within this sulfur range.	BTU/GAL	I6
6	02SHNA	AVERAGE FOR ALL FUEL OIL The average heat content of all the fuel oil purchased is the weighted average of the above. It is the total of BTUs in fuel oil purchased divided by the total number of gallons of fuel oil.	BTU/GAL	I6
		QUANTITY OF FUEL OIL PURCHASED		
7	02SFN1	LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The oil quantity is the total number of barrels (42 gallons) of oil consumed in power generation, within the sulfur range.	BLS	I8
8	02SFN2	FOR GREATER THAN 1.5% SULFUR CONTENT The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The oil quantity is the total number of barrels (42 gallons) of oil consumed in power generation, within the sulfur range.	BLS	I8

SPOT LIGHT OIL PURCHASES (12 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
9	02SFNT	TOTAL FUEL OIL CONSUMED	BLS	I8
		The total fuel oil quantity is the volume of oil, measured in barrels (42 gallons per barrel).		
		TOTAL COST OF FUEL OIL		
10	02SFC1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	$	I9
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The total cost of the fuel oil is the total allowable oil costs in dollars of the oil purchased.		
11	02SFC2	FOR GREATER THAN 1.5% SULFUR CONTENT	$	I9
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The total cost of the fuel oil is the total allowable oil costs in dollars of the oil purchased.		
12	02SFCT	TOTAL COST OF FUEL OIL	$	I9
		The total cost of fuel oil is the total allowable dollar costs of fuel oil purchased.		

SYSTEM DATA (6 Branches)
6th BRANCH: SYSTEM FUEL PURCHASE DATA
Record 10 of 17

BROKER LIGHT OIL PURCHASES (12 elements)

The total company wide Light Fuel Oil (furnace oil) which was purchased through a broker. The brokerage (intermediary) system of purchasing oil is a system where the broker arranges the purchases of oil for the utilities, with various suppliers at the best price. These purchases are for a short term period of less than one year.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE THERMAL ENERGY COSTS		
1	02BEC1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The total cost in cents of the oil (including allowable transportation costs) purchased within this sulfur range divided by the number of millions of BTUs in this oil equals the average thermal energy cost.		
2	02BEC2	FOR GREATER THAN 1.5% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The total cost in cents of the oil (including allowable transportation costs) purchased within this sulfur range divided by the number of millions of BTUs in this oil equals the average thermal energy cost.		
3	02BECA	AVERAGE FOR ALL FUEL OIL	¢/MMBTU	F7.3
		The total cost of all fuel oil purchased per million BTUs is the weighted average of the above. It is the total fuel oil costs in cents (including allowable transportation costs) divided by the total thermal energy input, in millions of BTUs.		

BROKER LIGHT OIL PURCHASES (12 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE HEAT CONTENT		
4	02BHN1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	BTU/GAL	I6
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The average heat content is the total BTUs in the fuel oil purchased divided by the total number of gallons of fuel oil within this sulfur range.		
5	02BHN2	FOR GREATER THAN 1.5% SULFUR CONTENT	BTU/GAL	I6
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The average heat content is the total BTUs in the fuel oil purchased divided by the total number of gallons of fuel oil within this sulfur range.		
6	02BHNA	AVERAGE FOR ALL FUEL OIL	BTU/GAL	I6
		The average heat content of all the fuel oil purchased is the weighted average of the above. It is the total of BTUs in fuel oil purchased divided by the total number of gallons of fuel oil.		
		QUANTITY OF FUEL OIL PURCHASED		
7	02BFN1	LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	BLS	I8
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The oil quantity is the total number of barrels (42 gallons) of oil consumed in power generation, within the sulfur range.		
8	02BFN2	FOR GREATER THAN 1.5% SULFUR CONTENT	BLS	I8
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The oil quantity is the total number of barrels (42 gallons) of oil consumed in power generation, within the sulfur range.		

BROKER LIGHT OIL PURCHASES (12 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
9	O2BFNT	TOTAL FUEL OIL CONSUMED	BLS	I8
		The total fuel oil quantity is the volume of oil, measured in barrels (42 gallons per barrel).		
		TOTAL COST OF FUEL OIL		
10	O2BFC1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	$	I9
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The total cost of the fuel oil is the total allowable oil costs in dollars of the oil purchased.		
11	O2BFC2	FOR GREATER THAN 1.5% SULFUR CONTENT	$	I9
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The total cost of the fuel oil is the total allowable oil costs in dollars of the oil purchased.		
12	O2BFCT	TOTAL COST OF FUEL OIL	$	I9
		The total cost of fuel oil is the total allowable dollar costs of fuel oil purchased.		

CONTRACT LIGHT OIL PURCHASES (12 elements)

The total company Light wide Fuel which was purchased under long term contracts. Long term contract purchases from suppliers are under contracts lasting at least one year.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE THERMAL ENERGY COSTS		
1	O2LEC1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The total cost in cents of the oil (including allowable transportation costs) purchased within this sulfur range divided by the number of millions of BTUs in this oil equals the average thermal energy cost.		
2	O2LEC2	FOR GREATER THAN 1.5% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The total cost in cents of the oil (including allowable transportation costs) purchased within this sulfur range divided by the number of millions of BTUs in this oil equals the average thermal energy cost.		
3	O2LECA	AVERAGE FOR ALL FUEL OIL	¢/MMBTU	F7.3
		The total cost of all fuel oil purchased per million BTUs is the weighted average of the above. It is the total fuel oil costs in cents (including allowable transportation costs) divided by the total thermal energy input, in millions of BTUs.		

CONTRACT LIGHT OIL PURCHASES (12 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE HEAT CONTENT		
4	02LHN1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	BTU/GAL	I6
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The average heat content is the total BTUs in the fuel oil purchased divided by the total number of gallons of fuel oil within this sulfur range.		
5	02LHN2	FOR GREATER THAN 1.5% SULFUR CONTENT	BTU/GAL	I6
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The average heat content is the total BTUs in the fuel oil purchased divided by the total number of gallons of fuel oil within this sulfur range.		
6	02LHNA	AVERAGE FOR ALL FUEL OIL	BTU/GAL	I6
		The average heat content of all the fuel oil purchased is the weighted average of the above. It is the total of BTUs in fuel oil purchased divided by the total number of gallons of fuel oil.		
		QUANTITY OF FUEL OIL PURCHASED		
7	02LFN1	LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	BLS	I8
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The oil quantity is the total number of barrels (42 gallons) of oil consumed in power generation, within the sulfur range.		
8	02LFN2	FOR GREATER THAN 1.5% SULFUR CONTENT	BLS	I8
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The oil quantity is the total number of barrels (42 gallons) of oil consumed in power generation, within the sulfur range.		

CONTRACT LIGHT OIL PURCHASES (12 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
9	02LFNT	TOTAL FUEL OIL CONSUMED	BLS	I8
		The total fuel oil quantity is the volume of oil, measured in barrels (42 gallons per barrel).		
		TOTAL COST OF FUEL OIL		
10	02LFC1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	$	I9
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The total cost of the fuel oil is the total allowable oil costs in dollars of the oil purchased.		
11	02LFC2	FOR GREATER THAN 1.5% SULFUR CONTENT	$	I9
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The total cost of the fuel oil is the total allowable oil costs in dollars of the oil purchased.		
12	02LFCT	TOTAL COST OF FUEL OIL	$	I9
		The total cost of fuel oil is the total allowable dollar costs of fuel oil purchased.		

TOTAL HEAVY OIL PURCHASES (12 elements)

The total company wide purchase of Heavy Fuel Oil, including Fuel Oils Nos. 4, 5 and 6, crude, and topped crude.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE THERMAL ENERGY COSTS		
1	04AEC1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The total cost in cents of the oil (including allowable transportation costs) purchased within this sulfur range divided by the number of millions of BTUs in this oil equals the average thermal energy cost.		
2	04AEC2	FOR GREATER THAN 1.5% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The total cost in cents of the oil (including allowable transportation costs) purchased within this sulfur range divided by the number of millions of BTUs in this oil equals the average thermal energy cost.		
3	04AECA	AVERAGE FOR ALL FUEL OIL	¢/MMBTU	F7.3
		The total cost of all fuel oil purchased per million BTUs is the weighted average of the above. It is the total fuel oil costs in cents (including allowable transportation costs) divided by the total thermal energy input, in millions of BTUs.		

TOTAL HEAVY OIL PURCHASES (12 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE HEAT CONTENT		
4	04AHN1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	BTU/GAL	I6
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The average heat content is the total BTUs in the fuel oil purchased divided by the total number of gallons of fuel oil within this sulfur range.		
5	04AHN2	FOR GREATER THAN 1.5% SULFUR CONTENT	BTU/GAL	I6
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The average heat content is the total BTUs in the fuel oil purchased divided by the total number of gallons of fuel oil within this sulfur range.		
6	04AHNA	AVERAGE FOR ALL FUEL OIL	BTU/GAL	I6
		The average heat content of all the fuel oil purchased is the weighted average of the above. It is the total of BTUs in fuel oil purchased divided by the total number of gallons of fuel oil.		
		QUANTITY OF FUEL OIL PURCHASED		
7	04AFN1	LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	BLS	I8
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The oil quantity is the total number of barrels (42 gallons) of oil consumed in power generation, within the sulfur range.		
8	04AFN2	FOR GREATER THAN 1.5% SULFUR CONTENT	BLS	I8
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The oil quantity is the total number of barrels (42 gallons) of oil consumed in power generation, within the sulfur range.		

TOTAL HEAVY OIL PURCHASES (12 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
9	04AFNT	TOTAL FUEL OIL CONSUMED	BLS	I8
		The total fuel oil quantity is the volume of oil, measured in barrels (42 gallons per barrel).		
		TOTAL COST OF FUEL OIL		
10	04AFC1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	$	I9
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The total cost of the fuel oil is the total allowable oil costs in dollars of the oil purchased.		
11	04AFC2	FOR GREATER THAN 1.5% SULFUR CONTENT	$	I9
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The total cost of the fuel oil is the total allowable oil costs in dollars of the oil purchased.		
12	04AFCT	TOTAL COST OF FUEL OIL	$	I9
		The total cost of fuel oil is the total allowable dollar costs of fuel oil purchased.		

SPOT HEAVY OIL PURCHASES (12 elements)

The total company wide Heavy Fuel Oil which was purchased on the spot market. The spot market for oil is a market where oil is purchased from the supplier for immediate delivery or under contract for a duration of less than one year.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE THERMAL ENERGY COSTS		
1	04SEC1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The total cost in cents of the oil (including allowable transportation costs) purchased within this sulfur range divided by the number of millions of BTUs in this oil equals the average thermal energy cost.	¢/MMBTU	F7.3
2	04SEC2	FOR GREATER THAN 1.5% SULFUR CONTENT The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The total cost in cents of the oil (including allowable transportation costs) purchased within this sulfur range divided by the number of millions of BTUs in this oil equals the average thermal energy cost.	¢/MMBTU	F7.3
3	04SECA	AVERAGE FOR ALL FUEL OIL The total cost of all fuel oil purchased per million BTUs is the weighted average of the above. It is the total fuel oil costs in cents (including allowable transportation costs) divided by the total thermal energy input, in millions of BTUs.	¢/MMBTU	F7.3

SPOT HEAVY OIL PURCHASES (12 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE HEAT CONTENT		
4	04SHN1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	BTU/GAL	I6
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The average heat content is the total BTUs in the fuel oil purchased divided by the total number of gallons of fuel oil within this sulfur range.		
5	04SHN2	FOR GREATER THAN 1.5% SULFUR CONTENT	BTU/GAL	I6
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The average heat content is the total BTUs in the fuel oil purchased divided by the total number of gallons of fuel oil within this sulfur range.		
6	04SHNA	AVERAGE FOR ALL FUEL OIL	BTU/GAL	I6
		The average heat content of all the fuel oil purchased is the weighted average of the above. It is the total of BTUs in fuel oil purchased divided by the total number of gallons of fuel oil.		
		QUANTITY OF FUEL OIL PURCHASED		
7	04SFN1	LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	BLS	I8
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The oil quantity is the total number of barrels (42 gallons) of oil consumed in power generation, within the sulfur range.		
8	04SFN2	FOR GREATER THAN 1.5% SULFUR CONTENT	BLS	I8
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The oil quantity is the total number of barrels (42 gallons) of oil consumed in power generation, within the sulfur range.		

SPOT HEAVY OIL PURCHASES (12 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
9	04SFNT	TOTAL FUEL OIL CONSUMED	BLS	I8
		The total fuel oil quantity is the volume of oil, measured in barrels (42 gallons per barrel).		
		TOTAL COST OF FUEL OIL		
10	04SFC1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	$	I9
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The total cost of the fuel oil is the total allowable oil costs in dollars of the oil purchased.		
11	04SFC2	FOR GREATER THAN 1.5% SULFUR CONTENT	$	I9
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The total cost of the fuel oil is the total allowable oil costs in dollars of the oil purchased.		
12	04SFCT	TOTAL COST OF FUEL OIL	$	I9
		The total cost of fuel oil is the total allowable dollar costs of fuel oil purchased.		

SYSTEM DATA (6 Branches)
6th BRANCH: SYSTEM FUEL PURCHASE DATA
Record 14 of 17

BROKER HEAVY OIL PURCHASES (12 elements)

The total company wide Heavy Fuel Oil which was purchased through a broker. The brokerage (intermediary) system pf purchasing oil is a system where the broker arranges the purchases of oil for the utilities, with various suppliers at the best price. These purchases are for a short term period of less than one year.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE THERMAL ENERGY COSTS		
1	04BEC1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The total cost in cents of the oil (including allowable transportation costs) purchased within this sulfur range divided by the number of millions of BTUs in this oil equals the average thermal energy cost.		
2	04BEC2	FOR GREATER THAN 1.5% SULFUR CONTENT	¢/MMBTU	F7.3
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The total cost in cents of the oil (including allowable transportation costs) purchased within this sulfur range divided by the number of millions of BTUs in this oil equals the average thermal energy cost.		
3	04BECA	AVERAGE FOR ALL FUEL OIL	¢/MMBTU	F7.3
		The total cost of all fuel oil purchased per million BTUs is the weighted average of the above. It is the total fuel oil costs in cents (including allowable transportation costs) divided by the total thermal energy input, in millions of BTUs.		

BROKER HEAVY OIL PURCHASES (12 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE HEAT CONTENT		
4	04BHN1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	BTU/GAL	I6
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The average heat content is the total BTUs in the fuel oil purchased divided by the total number of gallons of fuel oil within this sulfur range.		
5	04BHN2	FOR GREATER THAN 1.5% SULFUR CONTENT	BTU/GAL	I6
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The average heat content is the total BTUs in the fuel oil purchased divided by the total number of gallons of fuel oil within this sulfur range.		
6	04BHNA	AVERAGE FOR ALL FUEL OIL	BTU/GAL	I6
		The average heat content of all the fuel oil purchased is the weighted average of the above. It is the total of BTUs in fuel oil purchased divided by the total number of gallons of fuel oil.		
		QUANTITY OF FUEL OIL PURCHASED		
7	04BFN1	LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	BLS	I8
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The oil quantity is the total number of barrels (42 gallons) of oil consumed in power generation, within the sulfur range.		
8	04BFN2	FOR GREATER THAN 1.5% SULFUR CONTENT	BLS	I8
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The oil quantity is the total number of barrels (42 gallons) of oil consumed in power generation, within the sulfur range.		

BROKER HEAVY OIL PURCHASES (12 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
9	04BFNT	TOTAL FUEL OIL CONSUMED	BLS	I8
		The total fuel oil quantity is the volume of oil, measured in barrels (42 gallons per barrel).		
		TOTAL COST OF FUEL OIL		
10	04BFC1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	$	I9
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The total cost of the fuel oil is the total allowable oil costs in dollars of the oil purchased.		
11	04BFC2	FOR GREATER THAN 1.5% SULFUR CONTENT	$	I9
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The total cost of the fuel oil is the total allowable oil costs in dollars of the oil purchased.		
12	04BFCT	TOTAL COST OF FUEL OIL	$	I9
		The total cost of fuel oil is the total allowable dollar costs of fuel oil purchased.		

CONTRACT HEAVY OIL PURCHASES (12 elements)

The total company wide Heavy Fuel Oil which was purchased under long term contracts. Long term contract purchases from suppliers are under contracts lasting at least one year.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE THERMAL ENERGY COSTS		
1	04LEC1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The total cost in cents of the oil (including allowable transportation costs) purchased within this sulfur range divided by the number of millions of BTUs in this oil equals the average thermal energy cost.	¢/MMBTU	F7.3
2	04LEC2	FOR GREATER THAN 1.5% SULFUR CONTENT The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The total cost in cents of the oil (including allowable transportation costs) purchased within this sulfur range divided by the number of millions of BTUs in this oil equals the average thermal energy cost.	¢/MMBTU	F7.3
3	04LECA	AVERAGE FOR ALL FUEL OIL The total cost of all fuel oil purchased per million BTUs is the weighted average of the above. It is the total fuel oil costs in cents (including allowable transportation costs) divided by the total thermal energy input, in millions of BTUs.	¢/MMBTU	F7.3

CONTRACT HEAVY OIL PURCHASES (12 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		AVERAGE HEAT CONTENT		
4	04LHN1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	BTU/GAL	I6
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The average heat content is the total BTUs in the fuel oil purchased divided by the total number of gallons of fuel oil within this sulfur range.		
5	04LHN2	FOR GREATER THAN 1.5% SULFUR CONTENT	BTU/GAL	I6
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The average heat content is the total BTUs in the fuel oil purchased divided by the total number of gallons of fuel oil within this sulfur range.		
6	04LHNA	AVERAGE FOR ALL FUEL OIL	BTU/GAL	I6
		The average heat content of all the fuel oil purchased is the weighted average of the above. It is the total of BTUs in fuel oil purchased divided by the total number of gallons of fuel oil.		
		QUANTITY OF FUEL OIL PURCHASED		
7	04LFN1	LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	BLS	I8
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The oil quantity is the total number of barrels (42 gallons) of oil consumed in power generation, within the sulfur range.		
8	04LFN2	FOR GREATER THAN 1.5% SULFUR CONTENT	BLS	I8
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The oil quantity is the total number of barrels (42 gallons) of oil consumed in power generation, within the sulfur range.		

CONTRACT HEAVY OIL PURCHASES (12 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
9	04LFNT	TOTAL FUEL OIL CONSUMED	BLS	I8
		The total fuel oil quantity is the volume of oil, measured in barrels (42 gallons per barrel).		
		TOTAL COST OF FUEL OIL		
10	04LFC1	FOR LESS THAN OR EQUAL TO 1.5% SULFUR CONTENT	$	I9
		The sulfur content of the fuel oil is less than or equal to 1.5% of the total volume of the oil. The total cost of the fuel oil is the total allowable oil costs in dollars of the oil purchased.		
11	04LFC2	FOR GREATER THAN 1.5% SULFUR CONTENT	$	I9
		The sulfur content of the fuel oil is greater than 1.5% of the total volume of the oil. The total cost of the fuel oil is the total allowable oil costs in dollars of the oil purchased.		
12	04LFCT	TOTAL COST OF FUEL OIL	$	I9
		The total cost of fuel oil is the total allowable dollar costs of fuel oil purchased.		

SYSTEM DATA (6 Branches)
6th BRANCH: SYSTEM FUEL PURCHASE DATA
Record 16 of 17

NATURAL GAS PURCHASES (4 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	NGECT	THERMAL ENERGY COST FOR NATURAL GAS	¢/MMBTU	F7.3
		The thermal energy cost of natural gas is the total cost in cents of all natural gas purchased divided by the number of millions of BTUs in this natural gas.		
2	NGHC	HEAT CONTENT NATURAL GAS	BTU/FT^3	I4
		The heat content of natural gas is the total BTUs in the natural gas purchased divided by the total number of cubic feet of this natural gas.		
3	NGFLC	QUANTITY OF NATURAL GAS PURCHASED	MCF	I7
		The natural gas quantity is the total number of thousands of cubic feet of natural gas purchased.		
4	NGTCT	TOTAL COST NATURAL GAS	$	I9
		The total cost of natural gas is the total allowable dollar cost of natural gas purchased.		

SYSTEM DATA (6 Branches)
3rd BRANCH: SYSTEM FUEL PURCHASE DATA
Record 17 of 17

NUCLEAR FUEL ACQUISITION COSTS (4 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	NCLTFC	TOTAL NUCLEAR FUEL COST	$	I9
		The total nuclear fuel cost is the total dollar costs associated with the purchase of yellowcake, the purchase of nuclear fuel in process, and the purchase of completed nuclear fuel assemblies.		
2	NCYELC	NUCLEAR - YELLOWCAKE	$	I9
		Cost, in dollars, of yellowcake (uranium ore concentrate U_3O_8) purchased. The cost includes only those costs which are allowed under the Virginia fuel clause.		
3	NCIPRO	NUCLEAR - IN PROCESS	$	I9
		Cost, in dollars, of nuclear fuel purchased at one of the steps of processing between the initial ore (yellowcake) and the completed fuel assembly. The various stages of completion at which nuclear fuel might be purchased are refining, enrichment, conversion, and fabrication. The cost includes only those costs which are allowable under the Virginia fuel clause.		
4	NCFUAS	NUCLEAR FUEL ASSEMBLIES	$	I9
		Cost, in dollars, of completed nuclear fuel assemblies purchased. The cost includes only those costs which are allowable under the Virginia fuel clause.		

PLANT DATA - 5 Branches

I PLANT FIXED PARAMETER DATA - 1 record (5 elements)

II PLANT GENERATION DATA - 1 record (3 elements)

III PLANT FUEL CONSUMPTION DATA - 2 records

1. Plant Fuel Consumption by Fuel Type (21 elements)
2. Fossil Fuel Inventory, Quantity and Cost (39 elements)

IV PLANT ACCOUNTING ADJUSTMENTS - 1 record (24 elements)

V PLANT FUEL PURCHASE DATA - N records (one per invoice; 13 elements per record)

PLANT DATA (5 Branches)
1st BRANCH: PLANT FIXED PARAMETER DATA
Record 1 of 1

FIXED PLANT DATA (5 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	PLTNO	PLANT NUMBER The six-digit plant identification number which uniquely identifies the unit relative to other plants of companies serving Virginia is reported. See Exhibit A for list of plant numbers.		I6
2	PLTNAM	PLANT NAME The name of the plant is reported in alphabetic characters.		
3	PLTLOC	PLANT LOCATION The nearest town and the state in which the plant is located are reported in alphabetic characters.		
4	NUMUNT	NUMBER OF UNITS AT PLANT SITE The number of generating units at the plant site is reported.		
5	PUNTND	LIST OF THE VSCC UNIT NUMBERS AT PLANT SITE Reported here are the six-digit unit identification numbers for units at this plant.		

PLANT DATA (5 Branches)
2nd BRANCH: PLANT GENERATION DATA
Record 1 of 1

PLANT GENERATION (3 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	PLTNO	PLANT NUMBER The plant identification number.		
2	GGENPT	TOTAL GROSS PLANT GENERATION The total energy generated by the plant during the reporting period.	MWH	I8
3	NGENPT	TOTAL NET PLANT GENERATION The gross plant generation less the auxiliary energy required by the plant.	MWH	I8

PLANT FUEL CONSUMPTION BY FUEL TYPE (21 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE

FIRST FUEL TYPE

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	F1TYPE	FUEL TYPE		I1

Enter one of the following numbers, for the fuel used to generate the most energy at the plant.

1 coal
2 nuclear
3 light fuel oil
4 heavy fuel oil
5 natural gas

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
2	F1GGEN	GROSS GENERATION BY FUEL	MWH	J8

The total electric energy generated by the fuel type at the plant during the reporting period.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
3	F1NGEN	NET GENERATION BY FUEL	MWH	J8

The gross generation by the fuel type less the auxiliary energy required by the units at the plant.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
4	F1BTUC	AVERAGE COST OF FUEL CONSUMED	¢/MMBTU	F7.3

The average cost of primary fuel consumed is the weighted average cost per MMBTU of the fuel consumed during the reporting period. For a fossil fuel, it is the weighted average cost of the fuel consumed during the period. For nuclear fuel, it is the amortization of the burn for all in-core assemblies divided by the gross heat generation in millions of BTUs. For both fossil and nuclear fuels, this average cost does not include cost components not allowed in the Virginia fuel clause.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
5	F1QCN	QUANTITY OF FUEL CONSUMED	(UNIT)	I8

The total number of units of the fuel consumed for generation in tons, barrels, MCF, etc. For nuclear fuel, enter the gross heat generation in megawatt-days.

PLANT FUEL CONSUMPTION BY FUEL TYPE (21 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
6	F1AHCN	AVERAGE HEAT CONTENT OF FUEL CONSUMED	BTU/(UNIT)	I8

The weighted average heat content of the fuel in BTUs per delivered unit (e.g. BTUs/lb., BTUs/gal., BTUs/assembly, etc.).

7	F1TUTC	TOTAL COST OF FUEL CONSUMED	$	I9

The total cost of the at the plant fuel consumed for generation in thousands of dollars is reported. This cost does not contain cost components not allowable in the Virginia fuel clause.

SECOND FUEL TYPE

8	F2TYPE	FUEL TYPE		I1

Enter one of the following numbers, for the fuel used to generate the second most energy at the plant.

1 coal
2 nuclear
3 light fuel oil
4 heavy fuel oil
5 natural gas

9	F2GGEN	GROSS GENERATION BY FUEL	MWH	J8

The total electric energy generated by the fuel type at the plant during the reporting period.

10	F2NGEN	NET GENERATION BY FUEL	MWH	J8

The gross generation by the fuel type less the auxiliary energy required by the units at the plant.

11	F2BTUC	AVERAGE COST OF FUEL CONSUMED	¢/MMBTU	F7.3

The average cost of second fuel consumed is the weighted average cost per MMBTU of the fuel consumed during the reporting period. For a fossil fuel, it is the weighted average cost of the fuel consumed during the period. For nuclear fuel, it is the amortization of the burn for all in-core assemblies divided by the gross heat generation in millions of BTUs. For both fossil and nuclear fuels, this average cost does not include cost components not allowed in the Virginia fuel clause.

PLANT FUEL CONSUMPTION BY FUEL TYPE (21 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
12	F2QCN	QUANTITY OF FUEL CONSUMED	(UNIT)	I8
		The total number of units of the fuel consumed for generation in tons, barrels, MCF, etc. For nuclear fuel, enter the gross heat generation in megawatt-days.		
13	F2AHCN	AVERAGE HEAT CONTENT OF FUEL CONSUMED	BTU/(UNIT)	I8
		The weighted average heat content of the fuel in BTUs per delivered unit (e.g. BTUs/lb., BTUs/gal., BTUs/assembly, etc.).		
14	F2TUTC	TOTAL COST OF FUEL CONSUMED	$	I9
		The total cost of fuel consumed for generation in the plant in thousands of dollars is reported. This cost does not contain cost components not allowable in the Virginia fuel clause.		
		THIRD FUEL TYPE		
15	F3TYPE	FUEL TYPE		I1
		Enter one of the following numbers, for the fuel used to generate the third most energy at the plant. 1 coal 2 nuclear 3 light fuel oil 4 heavy fuel oil 5 natural gas		
16	F3GGEN	GROSS GENERATION BY FUEL	MWH	J8
		The total energy generated by the fuel type at the plant during the reporting period.		
17	F3NGEN	NET GENERATION BY FUEL	MWH	J8
		The gross generation by the fuel type less the auxiliary energy required by the units at the plant.		

PLANT FUEL CONSUMPTION BY FUEL TYPE (21 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
18	F3BTUC	AVERAGE COST OF FUEL	¢/MMBTU	F7.3

The average cost of the third fuel consumed is the weighted average cost per MMBTU of the fuel consumed during the reporting period. For a fossil fuel, it is the weighted average cost of the fuel consumed during the period. For nuclear fuel, it is the amortization of the burn for all in-core assemblies divided by the gross heat generation in millions of BTUs. For both fossil and nuclear fuels, this average cost does not include cost components not allowed in the Virginia fuel clause.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
19	F3QCN	QUANTITY OF FUEL CONSUMED	(UNIT)	I8

The total number of units of the fuel consumed for generation in tons, barrels, MCF, etc. For nuclear fuel, enter the gross heat generation in megawatt-days.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
20	F3AHCN	AVERAGE HEAT CONTENT OF FUEL CONSUMED	BTU/(UNIT)	I8

The weighted average heat content of the fuel in BTUs per delivered unit (e.g. BTUs/lb., BTUs/gal., BTUs/assembly, etc.).

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
21	F3TUTC	TOTAL COST OF FUEL CONSUMED	$	I9

The total cost of the fuel consumed for generation at the plant in thousands of dollars is reported. This cost does not contain cost components not allowable in the Virginia fuel clause.

PLANT FOSSIL FUEL INVENTORY, QUANTITY AND COST (39 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
		INVENTORY OF PRIMARY FUEL		
1	F1TYPE	PRIMARY FUEL TYPE The primary fuel used by the plant for generation is reported. Enter one of the following numbers. 1 coal 3 light fuel oil 4 heavy fuel oil 5 natural gas		I7
2	F1OHBM	BEGINNING INVENTORY - UNITS Beginning inventory is the number of units (tons of coal; barrels of oil; MCF of gas in storage, if any) of primary fuel at the plant site at the beginning of the reporting period (month, quarter, or year).		I7
3	F1ADUT	ADJUSTMENTS IN REPORTING PERIOD FOR PRIOR PERIODS - UNITS The number of units of the fuel representing the sum of the inventory quality adjustments which occurred during the reporting period for fuel purchased in prior periods.		I7
4	F1ADDM	PURCHASES - UNITS Purchases are the number of units of primary fuel purchased for the plant site and recorded in inventory during the reporting period.		I7
5	F1TOTU	TOTAL UNITS AVAILABLE Total units is the sum of (a) units on-hand at the beginning of the reporting period, (b) units added during the reporting period, and (c) adjustments in reporting period for prior periods.		I7

PLANT FOSSIL FUEL INVENTORY, QUANTITY AND COST (39 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
6	F1USDM	REPORTING PERIOD CONSUMPTION - UNITS		I7
		Reporting period consumption is the total number of units of primary fuel consumed for generation in tons, barrels, MCF.		
7	F1OHEM	ENDING INVENTORY - UNITS		I7
		Ending inventory is the number of units of primary fuel recorded in inventory at the end of the reporting period.		
		COST OF PRIMARY FUEL		
8	F1OHBC	BEGINNING INVENTORY - COST	$	I8
		Beginning inventory is the book value of the units of primary fuel on-hand at the beginning of the reporting period. This value must be based on FOB plant costs only.		
9	F1ADCT	ADJUSTMENTS IN REPORTING PERIOD FOR PRIOR PERIODS - COST	$	I8
		The total dollar value of the accounting adjustments made for BTU content, sulfur content, ash content, escalator clauses, supplier settlement, and other.		
10	F1ADDC	PURCHASES - COST	$	I8
		Purchases are the cost, FOB plant, of primary fuel purchased for the plant site and recorded in inventory during the reporting period.		
11	F1TOTC	COST OF TOTAL UNITS AVAILABLE	$	I8
		Total cost of units is the sum of cost of units on-hand at the beginning of the reporting period, cost of units added during the reporting period, and cost adjustments.		

PLANT FOSSIL FUEL INVENTORY, QUANTITY AND COST (39 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
12	F1USDC	REPORTING PERIOD CONSUMPTION-COST	$	I8

$$F1USDC = F1USDM \times \frac{F1TOTC}{F1TOTU}$$

$$\text{Reporting Period Consumption} - \text{Cost} = \text{Reporting Period Consumption} - \text{Units} \times \frac{\text{Cost of Total Units Available}}{\text{Total Units Available}}$$

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
13	F1OHEC	ENDING INVENTORY - COST	$	I8

The total cost of units recorded in inventory at the end of the reporting period is the cost of total units available less the cost of reporting period consumption.

INVENTORY OF SECONDARY FUEL

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
14	F2TYPE	SECONDARY FUEL TYPE		I7

A secondary fuel used by the plant for generation is reported. Enter one of the following numbers.

1 coal
3 light fuel oil
4 heavy fuel oil
5 natural gas

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
15	F2OHBM	BEGINNING INVENTORY - UNITS		I7

Beginning inventory is the number of units (tons of coal; barrels of oil; MCF of gas in storage, if any) of secondary fuel at the plant site at the beginning of the reporting period (month, quarter, or year).

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
16	F2ADUT	ADJUSTMENTS IN REPORTING PERIOD FOR PRIOR PERIODS - UNITS		I7

The number of units of the fuel representing the sum of the inventory quality adjustments which occurred during the reporting period for fuel purchased in prior periods.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
17	F2ADDM	PURCHASES - UNITS		I7

Purchases are the number of units of secondary fuel purchased for the plant site and recorded in inventory during the reporting period.

PLANT FOSSIL FUEL INVENTORY, QUANTITY AND COST (39 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
18	F2TOTU	TOTAL UNITS AVAILABLE		I7
		Total units is the sum of (a) units on-hand at the beginning of the reporting period, (b) units added during the reporting period, and (c) adjustments in reporting period for prior periods.		
19	F2USDM	REPORTING PERIOD CONSUMPTION - UNITS		I7
		Reporting period consumption is the total number of units of secondary fuel consumed for generation in tons, barrels, MCF.		
20	F2OHEM	ENDING INVENTORY - UNITS		I7
		Ending inventory is the number of units of secondary fuel recorded in inventory at the end of the reporting period.		
		COST OF SECONDARY FUEL		
21	F2OHBC	BEGINNING INVENTORY - COST	$	I8
		Beginning inventory is the book value of the units of secondary fuel on-hand at the beginning of the reporting period. This value must be based on FOB plant costs only.		
22	F2ADCT	ADJUSTMENTS IN REPORTING PERIOD FOR PRIOR PERIODS - COST	$	I8
		The total dollar value of the accounting adjustments made for BTU content, sulfur content, ash content, escalator clauses, supplier settlement, and other.		
23	F2ADDC	PURCHASES - COST	$	I8
		Purchases are the cost, FOB plant, of secondary fuel purchased for the plant site and recorded in inventory during the reporting period.		

PLANT FOSSIL FUEL INVENTORY, QUANTITY AND COST (39 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
24	F2TOTC	COST OF TOTAL UNITS AVAILABLE	$	I8

Total cost of units is the sum of cost of units on-hand at the beginning of the reporting period, cost of units added during the reporting period, and cost adjustments.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
25	F2USDC	REPORTING PERIOD CONSUMPTION-COST	$	I8

$$\text{F2USDC} = \text{F2USDM} \times \frac{\text{F2TOTC}}{\text{F2TOTU}}$$

$$\text{Reporting Period Consumption - Cost} = \text{Reporting Period Consumption - Units} \times \frac{\text{Cost of Total Units Available}}{\text{Total Units Available}}$$

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
26	F2OHEC	ENDING INVENTORY - COST	$	I8

The total cost of units recorded in inventory at the end of the reporting period is the cost of total units available less the cost of reporting period consumption.

INVENTORY OF TERTIARY FUEL

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
27	F3TYPE	TERTIARY FUEL TYPE		I7

Any tertiary fuel used by the plant for generation is reported. Enter one of the following numbers.

1 coal
3 light fuel oil
4 heavy fuel oil
5 natural gas

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
28	F3OHBM	INVENTORY - UNITS		I7

Beginning inventory is the number of units (tons of coal; barrels of oil; MCF of gas in storage, if any) of tertiary fuel at the plant site at the beginning of the reporting period (month, quarter, or year).

PLANT FOSSIL FUEL INVENTORY, QUANTITY AND COST (39 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
29	F3ADUT	ADJUSTMENTS IN REPORTING PERIOD FOR PRIOR PERIODS - UNITS		I7
		The number of units of the fuel representing the sum of the inventory quality adjustments which occurred during the reporting period for fuel purchased in prior periods.		
30	F3ADDM	PURCHASES - UNITS		I7
		Purchases are the number of units of tertiary fuel purchased for the plant site and recorded in inventory during the reporting period.		
31	F3TOTU	TOTAL UNITS AVAILABLE		I7
		Total units is the sum of (a) units on-hand at the beginning of the reporting period, (b) units added during the reporting period, and (c) adjustments in reporting period for prior periods.		
32	F3USDM	REPORTING PERIOD CONSUMPTION - UNITS		I7
		Reporting period consumption is the total number of units of tertiary fuel consumed for generation in tons, barrels, MCF.		
33	F3OHEM	ENDING INVENTORY - UNITS		I7
		Ending inventory is the number of units of tertiary fuel recorded in inventory at the end of the reporting period.		
		COST OF TERTIARY FUEL		
34	F3OHBC	BEGINNING INVENTORY - COST	$	I8
		Beginning inventory is the book value of the units of tertiary fuel on-hand at the beginning of the reporting period. This value must be based on FOB plant costs only.		

PLANT FOSSIL FUEL INVENTORY, QUANTITY AND COST (39 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
35	F3ADCT	ADJUSTMENTS IN REPORTING PERIOD FOR PRIOR PERIODS - COST	$	I8
		The total dollar value of the accounting adjustments made for BTU content, sulfur content, ash content, escalator clauses, supplier settlement, and other.		
36	F3ADDC	PURCHASES - COST	$	I8
		Purchases are the cost, FOB plant, of tertiary fuel purchased for the plant site and recorded in inventory during the reporting period.		
37	F3TOTC	COST OF TOTAL UNITS AVAILABLE	$	I8
		Total cost of units is the sum of cost of units on-hand at the beginning of the reporting period, cost of units added during the reporting period, and cost adjustments.		
38	F3USDC	REPORTING PERIOD CONSUMPTION-COST	$	I8

$$F3USDC = F3USDM \times \frac{F3TOTC}{F3TOTU}$$

$$\text{Reporting Period Consumption} - \text{Cost} = \text{Reporting Period Consumption} - \text{Units} \times \frac{\text{Cost of Total Units Available}}{\text{Total Units Available}}$$

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
39	F3OHEC	ENDING INVENTORY - COST	$	I8
		The total cost of units recorded in inventory at the end of the reporting period is the cost of total units available less the cost of reporting period consumption.		

PLANT DATA (5 Branches)
4th BRANCH: PLANT FUEL INVENTORY COST ADJUSTMENTS
Record 1 of 1

PLANT ACCOUNTING ADJUSTMENTS (24 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE

ADJUSTMENTS OCCURRING DURING THE REPORTING PERIOD FOR FUELS PURCHASED DURING PRIOR PERIODS

FIRST FUEL TYPE

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	F1TYPE	FUEL TYPE		I7

The primary fuel used by the plant for generation is reported. Enter one of the following numbers:

1 coal
3 light fuel oil
4 heavy fuel oil
5 natural gas

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
2	P1JBTU	BTU CONTENT ADJUSTMENT (PLANT)	$	I8

This adjustment contains the total dollar adjustments in plant primary fuel inventory value due to purchase contract price adjustments caused by thermal energy differences. Adjustments to the dollar value of fuel inventory result from the thermal energy, measured in British thermal units, being below or above the amount specified in the purchase contract.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
3	P1JSUF	SULFUR CONTENT ADJUSTMENT (PLANT)	$	I9

This adjustment contains the total dollar change in plant primary fuel inventory value due to purchase contract price adjustments caused by the sulfur content in the fuels differing from the amounts specified in the purchase contracts. The sulfur content of a fuel is the amount of sulfur by weight or volume contained in the fuel.

PLANT ACCOUNTING ADJUSTMENTS (24 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
4	P1JASH	ASH CONTENT ADJUSTMENT (PLANT)	$	I8
		This adjustment contains the total dollar change in plant primary fuel inventory value due to purchase contract price adjustments caused by the ash content in the fuels differing from the amounts specified in the purchase contracts. The ash content of a fuel is the amount of solid residue left when combustible material is thoroughly burned. The higher the ash content, the higher the disposal cost.		
5	P1JECL	ESCALATION CLAUSE ADJUSTMENT (PLANT)	$	I8
		This adjustment contains the total dollar adjustments to plant primary fuel inventory value due to escalation price increases which occur during the reporting period for purchases in prior periods. Escalation clauses are clauses built into long term fuel contract to provide for price increases linked to certain supplier cost increases. These adjustments occur for fuel purchased and paid for in earlier months.		
6	P1JSET	SUPPLIER SETTLEMENTS ADJUSTMENT (PLANT)	$	I8
		This adjustment contains the total dollar adjustments to plant primary fuel inventory values caused by supplier settlements. Supplier settlements are refunds or additional billings for prior expenses where legal action or negotiations have brought settlements of such disputes as contract standards, transportation methods and costs, or weighting errors of the supplier or common carrier.		
7	P1JOTH	OTHER ADJUSTMENTS (PLANT)	$	I8
		Other adjustments are any plant inventory value changes, exclusive of those provided for above, in the book value of the primary fuel inventories.		
8	P1JTOT	TOTAL ADJUSTMENTS (PLANT)	$	I8
		This classification is the sum of the primary fuel inventory adjustments, in dollars, which occur during the reporting period for fuels purchased in prior periods.		

PLANT ACCOUNTING ADJUSTMENTS (24 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE

SECOND FUEL TYPE

9	F2TYPE	FUEL TYPE		I7

The secondary fuel used by the plant for generation is reported. Enter one of the following numbers:

1 coal
3 light fuel oil
4 heavy fuel oil
5 natural gas

10	P2JBTU	BTU CONTENT ADJUSTMENT (PLANT)	$	I8

This adjustment contains the total dollar adjustments in plant secondary fuel inventory value due to purchase contract price adjustments caused by thermal energy differences. Adjustments to the dollar value of fuel inventory result from the thermal energy, measured in British thermal units, being below or above the amount specified in the purchase contract.

11	P2JSUF	SULFUR CONTENT ADJUSTMENT (PLANT)	$	I9

This adjustment contains the total dollar change in plant secondary fuel inventory value due to purchase contract price adjustments caused by the sulfur content in the fuels differing from the amounts specified in the purchase contracts. The sulfur content of a fuel is the amount of sulfur by weight or volume contained in the fuel.

12	P2JASH	ASH CONTENT ADJUSTMENT (PLANT)	$	I8

This adjustment contains the total dollar change in plant secondary fuel inventory value due to purchase contract price adjustments caused by the ash content in the fuels differing from the amounts specified in the purchase contracts. The ash content of a fuel is the amount of solid residue left when combustible material is thoroughly burned. The higher the ash content, the higher the disposal cost.

PLANT ACCOUNTING ADJUSTMENTS (24 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
13	P2JECL	ESCALATION CLAUSE ADJUSTMENT (PLANT)	$	I8

This adjustment contains the total dollar adjustments to plant secondary fuel inventory value due to escalation price increases which occur during the reporting period for purchases in prior periods. Escalation clauses are clauses built into long term fuel contract to provide for price increases linked to certain supplier cost increases. These adjustments occur for fuel purchased and paid for in earlier months.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
14	P2JSET	SUPPLIER SETTLEMENTS ADJUSTMENT (PLANT)	$	I8

This adjustment contains the total dollar adjustments to plant secondary fuel inventory values caused by supplier settlements. Supplier settlements are refunds or additional billings for prior expenses where legal action or negotiations have brought settlements of such disputes as contract standards, transportation methods and costs, or weighting errors of the supplier or common carrier.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
15	P2JOTH	OTHER ADJUSTMENTS (PLANT)	$	I8

Other adjustments are any plant inventory value changes, exclusive of those provided for above, in the book value of the secondary fuel inventories.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
16	P2JTOT	TOTAL ADJUSTMENTS (PLANT)	$	I8

This classification is the sum of the secondary fuel inventory adjustments, in dollars, which occur during the reporting period for fuels purchased in prior periods.

THIRD FUEL TYPE

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
17	F3TYPE	FUEL TYPE		I7

The tertiary fuel used by the plant for generation is reported. Enter one of the following numbers:

1 coal
3 light fuel oil
4 heavy fuel oil
5 natural gas

PLANT ACCOUNTING ADJUSTMENTS (24 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
18	P3JBTU	BTU CONTENT ADJUSTMENT (PLANT)	$	I8

This adjustment contains the total dollar adjustments in plant tertiary fuel inventory value due to purchase contract price adjustments caused by thermal energy differences. Adjustments to the dollar value of fuel inventory result from the thermal energy, measured in British thermal units, being below or above the amount specified in the purchase contract.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
19	P3JSUF	SULFUR CONTENT ADJUSTMENT (PLANT)	$	I9

This adjustment contains the total dollar change in plant tertiary fuel inventory value due to purchase contract price adjustments caused by the sulfur content in the fuels differing from the amounts specified in the purchase contracts. The sulfur content of a fuel is the amount of sulfur by weight or volume contained in the fuel.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
20	P3JASH	ASH CONTENT ADJUSTMENT (PLANT)	$	I8

This adjustment contains the total dollar change in plant tertiary fuel inventory value due to purchase contract price adjustments caused by the ash content in the fuels differing from the amounts specified in the purchase contracts. The ash content of a fuel is the amount of solid residue left when combustible material is thoroughly burned. The higher the ash content, the higher the disposal cost.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
21	P3JECL	ESCALATION CLAUSE ADJUSTMENT (PLANT)	$	I8

This adjustment contains the total dollar adjustments to plant tertiary fuel inventory value due to escalation price increases which occur during the reporting period for purchases in prior periods. Escalation clauses are clauses built into long term fuel contract to provide for price increases linked to certain supplier cost increases. These adjustments occur for fuel purchased and paid for in earlier months.

PLANT ACCOUNTING ADJUSTMENTS (24 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
22	P3JSET	SUPPLIER SETTLEMENTS ADJUSTMENT (PLANT)	$	I8
		This adjustment contains the total dollar adjustments to plant tertiary fuel inventory values caused by supplier settlements. Supplier settlements are refunds or additional billings for prior expenses where legal action or negotiations have brought settlements of such disputes as contract standards, transportation methods and costs, or weighting errors of the supplier or common carrier.		
23	P3JOTH	OTHER ADJUSTMENTS (PLANT)	$	I8
		Other adjustments are any plant inventory value changes, exclusive of those provided for above, in the book value of the tertiary fuel inventories.		
24	P3JTOT	TOTAL ADJUSTMENTS (PLANT)	$	I8
		This classification is the sum of the tertiary fuel inventory adjustments, in dollars, which occur during the reporting period for fuels purchased in prior periods.		

PLANT DATA (5 Branches)
5th BRANCH: PLANT FUEL PURCHASE DATA
N Records: all of this form. One record per fuel invoice.

PLANT FUEL PURCHASES (13 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	FYTYPE	FUEL TYPE Enter one of the following numbers to report the fuel type invoiced. 1 coal 2 nuclear 3 light fuel oil 4 heavy fuel oil 5 natural gas		I1
2	SUPLCD	SUPPLIER CODE The three-digit supplier identification code is reported. See Appendix A.		I3
3	QUANT	INVOICE QUANTITY Quantity by invoice is the number of units of the fuel type delivered during the reporting month which are recorded on the invoice corresponding to this record.	(UNIT)	I7
4	INVOCT	INVOICE COST OF FUEL PURCHASED, FOB SOURCE This cost is the F.O.B. cost of the fuel, at the supplier's mine or storage location. If this cost cannot be determined, enter 999999999.	$	I8
5	HTCONT	HEAT CONTENT OF FUEL PURCHASED The heat content of fuel purchased is the average of the measured values of the number of BTUs per unit in samples of the fuel invoiced.	MMBTU/(UNIT)	I6

PLANT FUEL PURCHASES (13 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
6	SULFCN	SULFUR CONTENT OF FUEL PURCHASED	%	F5.2
		The sulfur content of fuel purchased is the average of the measured values, expressed as a percentage, of the sulfur content of samples of the fuel invoiced.		
7	ASHCN	ASH CONTENT OF FUEL PURCHASED	%	F5.2
		The ash content of fuel purchased is the average of the measured values, expressed as a percentage, of the ash content of samples of the fuel invoiced.		
8	TRNMED	TRANSPORTATION METHOD		I2
		The two-digit transportation code is reported. Enter one of the following numbers. 1 Rail - non-affiliated 2 Rail - company owned or leased 3 Barge - river 4 Ship - ocean 5 Truck - tanker 6 Truck - barrels 7 Pipeline 8 Other		
9	TRANCT	TRANSPORTATION COST	%	I6
		The total cost of delivering the invoiced fuel quantity from the source (F.O.B.) to the plant (F.O.B.). If not obtainable, enter 999999.		
10	TNCPU	TRANSPORTATION COST PER UNIT	$/(UNIT)	F6.3
		The transportation cost per unit is the transportation cost divided by the invoiced fuel quantity.		
11	HTCTFL	AVERAGE COST OF FUEL PURCHASED, FOB SOURCE	$/MMBTU	F7.3
		The average cost of fuel purchased, F.O.B. source, is the invoice cost of fuel purchased, F.O.B. source, divided by the product of the heat content of the fuel purchased and the invoice quantity.		

PLANT FUEL PURCHASES (13 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
12	HTCTAN	AVERAGE TRANSPORTATION COST OF FUEL PURCHASED	¢/MMBTU	F7.3
		The average transportation cost of fuel purchased is the transportation cost divided by the product of the heat content of the fuel purchased and the invoice quantity.		
13	DLDATE	DELIVERY DATE		
		The delivery date is the day upon which delivery of an invoiced fuel quantity is completed.		

UNIT DATA - 4 Branches

I UNIT FIXED PARAMETER DATA - 1 record (18 elements)

II FOSSIL/NUCLEAR GENERATION & OPERATION DATA - 7 records

1. Capacity & Demand (6 elements)
2. Generation (7 elements)
3. Thermal Energy Consumption (6 elements)
4. Heat Rates (6 elements)
5. Time Designations (14 elements)
6. Performance Indices (13 elements)
7. Dispatching Lamdas (4 elements)

III HYDRO OPERATION & GENERATION DATA - 1 record (7 elements)

IV FOSSIL/NUCLEAR FUEL CONSUMPTION DATA - 3 records

1. Fossil Unit Fuel Consumption by Fuel Type (18 elements)
2. Nuclear Unit Fuel Consumption (25 elements)
3. Nuclear Unit Fuel Inventory, Quantity and Cost (29 elements)

UNIT DATA (4 Branches)
1st BRANCH: UNIT FIXED PARAMETER DATA
Record 1 of 1

FOSSIL/NUCLEAR/HYDRO FIXED PARAMETER DATA (18 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	VCSSNO	UNIT IDENTIFICATION NUMBER The six digit unit identification number which uniquely identifies the unit relative to all units of companies serving Virginia is listed. See Exhibit A for a list of unit numbers.		I6
2	UNAME	UNIT NAME The unique name of the unit.		A20
3	FACOWN	FRACTION OF UNIT OWNERSHIP The fraction of the unit owned or leased by the reporting company is given. This number is calculated based on the gross maximum capacity of the unit such that the maximum capacity available to the reporting company is the fraction of unit ownership times the maximum capacity of the unit.		F5.3
4	ONLMO	ON-LINE MONTH The month that the unit went into commerical service. Enter 01-12.		I2
5	ONLYR	ON-LINE YEAR The year that the unit went into commercial service. Enter the four digits of the year.		I4
6	OFLMO	OFF-LINE MONTH The month that the unit is expected to be retired from commercial service. If unknown, enter 12.		I2
7	OFLYR	OFF-LINE YEAR The year that the unit is expected to be retired from commerical service. If unknown, enter 1999.		I4

FOSSIL/NUCLEAR/HYDRO FIXED PARAMETER DATA (18 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
8	UNTYPE	UNIT TYPE		I1

The type of unit is given. Enter one of the following numbers:

1 steam-fossil
2 steam-nuclear
3 oil fired engine
4 gas turbine
5 jet engine
6 hydro-run of river
7 pumped storage
8 hydro-river storage

9	ULOAD	UNIT LOADING TYPE		I1

The relative loading order of the unit is given. Enter one of the following numbers:

1 base
2 intermediate (cycling)
3 peaking

where base loaded units are generally run at or near rated output, intermediate (cycling) loaded units are run at a load which varies widely with system demand and peak loaded units are run only during high demand periods.

10	GMC	GROSS MAXIMUM CAPACITY	MW	I4

The gross maximum capacity which the unit can produce over a four hour or longer period of time under minimum ambient restrictions is reported. This value should be defined in the same way as that reported as "..continuous plant (unit) capability when not limited by condenser water" in FPC/FERC Schedule 432. For hydro units report capacity under best flow conditions.

11	GDC	GROSS DEPENDABLE CAPACITY	MW	I4

The gross dependable capacity which is the gross maximum capacity modified for ambient limitations for a specified period of the year is reported. This value should be defined in the same way as that reported as "...continuous plant (unit) capability when limited by condenser water" in FPC/FERC Schedule 432. For hydro units report capacity under minimum expected flow conditions.

FOSSIL/NUCLEAR/HYDRO FIXED PARAMETER DATA (18 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
12	SMOLIM	STARTING MONTH OF AMBIENT LIMITED CAPACITY The starting month of the period during the year that the unit's capability is limited by condenser water or ambient temperature, or water flow for hydro units. If the unit is not limited enter 00.		I2
13	EMOLIM	ENDING MONTH OF AMBIENT LIMITED CAPACITY The last month of the period during the year that the unit's capability becomes limited by condenser water or ambient temperature, or water flow for hydro units. If the unit is not limited, enter 00.		I2
14	GENCAP	INSTALLED NAME PLATE CAPACITY The full-load continuous capacity of the unit as calculated in MW from the generator nameplate based on the rated power factor.	MW	I4
15	CAPCST	INSTALLED CAPACITY COST The capacity cost of the unit expressed in dolars per kW is given. This number is calculated by dividing the cost of the unit (land and land rights plus structure and improvements plus equipment costs) by the maximum gross capacity of the unit expressed in kW.	$/kW	I4
16	DHRHL	DESIGN HEAT RATE HALF LOAD Report the unit's design half load heat rate in BTUs/kWh. For nuclear units give estimated thermal consumption per kWh of generation. Leave blank for hydro units.	BTU/kWh	I5
17	DHR3QL	DESIGN HEAT RATE THREE QUARTERS LOAD Same as above but for unit operation at three-fourths load.	BTU/kWh	I5
18	DHRFL	DESIGN HEAT RATE FULL LOAD Same as above but for unit operation at full load.	BTU/kWh	I5

UNIT DATA (4 branches)
2nd BRANCH: FOSSIL/NUCLEAR GENERATION & OPERATION
Record 1 of 7

CAPACITY AND DEMAND DATA (6 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	VSCCNO	UNIT NUMBER Unit identification number.		I6
2	GDC	GROSS DEPENDABLE CAPACITY* The gross maximum capacity modified for ambient limitations during the reporting period	MW	I4
3	NDC	NET DEPENDABLE CAPACITY* The gross dependable capacity less the auxiliary power required by the unit when operated at gross dependable capacity.	MW	I4
4	GAC	GROSS AVAILABLE CAPACITY* The expected gross capacity which the unit can produce at any given time during the reporting period. This value would tend to fall between the gross maximum capacity and the gross dependable capacity.	MW	I4
5	NAC	NET AVAILABLE CAPACITY* The gross available capacity less auxiliary power required by the unit when operated at gross available capacity.	MW	I4
6	PEAKDM	NET PEAK DEMAND ON UNIT The net peak demand in the unit integrated over one hour.	MW	I4

*This definition follows that of the IEEE Power Plant Productivity Task Force report "Definitions for Use in Reporting Electric Generating Unit Reliability, Availability and Productivity".

UNIT DATA (4 Branches)
2nd BRANCH: FOSSIL/NUCLEAR GENERATION & OPERATION
Record 2 of 7

GENERATION DATA (7 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	VSCCNO	UNIT NUMBER The unit identification number.		I6
2	GGEN	GROSS GENERATION The total electric energy generated by the unit.	MWH	I7
3	NGEN	NET GENERATION The gross generation less the auxiliary energy required by the unit. For units which are part of multiple unit stations, the auxiliary energy will be apportioned to each unit.	MWH	I7
4	ENGPUM	ENERGY USED FOR PUMPING The energy produced by the unit for use in pumping at a principal storage unit.	MWH	I7
5	NGENHL	NET GENERATION AT HALF LOAD* The net generation of energy by the unit when operating at half load or less. If this value is not measured calculate it using a production cost model.	MWH	I7
6	NGEN3Q	NET GENERATION AT THREE-FOURTHS LOAD* The net generation of the unit when operating between half and three-fourths load.	MWH	I7
7	NGENFL	NET GENERATION AT FULL LOAD* The net generation of the unit when operating between three-fourths and full load.	MWH	I7

THERMAL ENERGY CONSUMPTION (6 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	VSCCND	UNIT NUMBER The unit identification number.		I6
2	NTHEN	NET THERMAL ENERGY CONSUMED The thermal energy used for net generation is reported. If this value is not measured calculate it from the average heat rate.	MMBTU	I8
3	GTHEN	GROSS THERMAL ENERGY CONSUMED The thermal energy used for gross generation is reported.	MMBTU	I8
4	THENHL	THERMAL ENERGY CONSUMED AT HALF LOAD The thermal energy consumed by the unit at net generation of half load or less.	MMBTU	I8
5	THEN3Q	THERMAL ENERGY CONSUMED AT THREE FOURTHS LOAD The thermal energy consumed by the unit at net generation between half and three-fourths load.	MMBTU	I8
6	THENFL	THERMAL ENERGY CONSUMED AT FULL LOAD The thermal energy conserved by the unit at net generation between three-fourths and full load.	MMBTU	I8

OPERATING HEAT RATE DATA (5 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	VSCCNO	UNIT NUMBER Unit identification number.		I6
2	OHRHL	HALF LOAD HEAT RATE The operating heat rate at half unit load.	BTU/kWh	I5
3	OHR3Q	THREE FOURTHS LOAD HEAT RATE The operating heat rate at three fourths load.	BTU/kWh	I5
4	OHRFL	FULL LOAD HEAT RATE The operating heat rate at full load.	BTU/kWh	I5
5	NHRAV	NET AVERAGE HEAT RATE The net average heat rate which is calculated by dividing the net thermal energy consumption by the net generation, then converting to the correct units.	BTU/kWh	I5
6	GHRAV	GROSS AVERAGE HEAT RATE The gross average heat rate which is calculated by dividing the gross thermal energy consumption for generation by the gross generation, then converting to the correct units.	BTU/kWh	I5

UNIT DATA (4 Branches)
2nd BRANCH: FOSSIL/NUCLEAR GENERATION & OPERATION
Record 5 of 7

TIME DESIGNATIONS* (14 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	VSCCND	UNIT NUMBER Unit identification number.		I6
2	AH	AVAILABLE HOURS The number of hours in the reporting period the unit was capable of providing service, whether or not it was actually in service, and regardless of the capacity level which could be obtained.	HRS	I4
3	SH	SERVICE HOURS The number of hours the unit was synchronized to the system.	HRS	I4
4	RSH	ECONOMY SHUT DOWN HOURS The number of hours the unit was available but not synchronized to the system.	HRS	I4
5	UH	UNAVAILABLE HOURS The number of hours the unit is not capable of operation because of testing, work being performed, or some adverse condition.	HRS	I4
6	POH	PLANNED OUTAGE HOURS The number of hours the unit is unavailable due to a, well in advance, scheduled outage for inspection, testing, refueling or overhaul.	HRS	I4
7	UOH	UNPLANNED OUTAGE HOURS The number of hours the unit is unavailable but is not unavailable due to a planned outage. Unplanned outage are classified according to one of five groupings:	HRS	I4

*The time designation definitions follow those developed by the IEEE Power Plant Productivity Task Force in their report "Definition for Use in Reporting Electric Generating Unit Reliability, Availability and Productivity".

TIME DESIGNATIONS (14 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE

Group 1 Unplanned Outage (Immediate)

An outage which requires immediate removal from service or prevents a unit from being placed in service if off-line. The unsuccessful attempt to bring a unit from shutdown to synchronism within a specified time period, which may vary for different units, shall be put in this class.

Group 2 Unplanned Outage (Delayed)

An outage which does not require the immediate removal of the unit from service but requires that the unit be removed from the available state within six hours.

Group 3 Unplanned Outage (Postponed)

An outage which can be postponed beyond six hours but which requires that the unit be removed from service before the end of the next weekend.

Group 4 Unplanned Outage (Deferred)

An outage which will allow the unit outage to be deferred beyond the end of the next weekend but which requires that a unit be removed from service before the next planned outage.

Group 5 Unplanned Outage (Extended)

An outage which is the extension (for any reason except startup failure) of a planned outage beyond its predetermined time.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
8	ROH	FORCED OUTAGE HOURS	HRS	I4
		The sum of the hours the unit was in unplanned outage groups 1, 2 and 3.		
9	PPOH	PARTIAL PLANNED OUTAGE HOURS	HRS	I4
		The number of hours during which a planned partial outage occurred.		
10	PUOH	PARTIAL UNPLANNED OUTAGE HOURS	HRS	I4
		The number of hours during which an unplanned partial outage occurred.		

TIME DESIGNATIONS (14 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
11	PFOH	PARTIAL FORCED OUTAGE HOURS	HRS	I4

The number of hours during which an unplanned partial outage occurred in outage groups 1, 2 and 3.

EQUIVALENT HOURS

The number of hours that the unit was in a derated state is expressed in terms of equivalent hours of full outage at gross maximum capacity by summing for all deratings the product of the gross derating and the number of hours at that derating, and dividing by the gross maximum capacity (GMC).

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
12	EPPOH	EQUIVALENT PARTIAL PLANNED OUTAGE HOURS	HRS	I4

The equivalent full outage hours calculated for partial planned outages.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
13	EPUOH	EQUIVALENT PARTIAL UNPLANNED OUTAGE HOURS	HRS	I4

The equivalent full outage hours calculated for unplanned outages.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
14	EPFOH	EQUIVALENT PARTIAL FORCED OUTAGE HOURS	HRS	I4

The equivalent full outage hours calculated for forced outages.

PERFORMANCE INDICES* (13 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	VSCCND	UNIT NUMBER		I6
		Unit identification number.		
2	GCF	GROSS CAPACITY FACTOR	%	F5.2
		$GCF = \frac{\text{Gross Generation (GGEN)} \times 100}{\text{Period Hours (PH)} \times \text{Gross Maximum Capacity (GMC)}}$		
3	NCF	NET CAPACITY FACTOR	%	F5.2
		$NCF = \frac{\text{Net Generation (NGEN)} \times 100}{\text{Period Hours (PH)} \times \text{Net Maximum Capacity (NMC)}}$		
4	OF	OUTPUT FACTOR	%	F5.2
		$OF = \frac{\text{Gross Generation (GGEN)} \times 100}{\text{Service Hours (SH)} \times \text{Gross Maximum Capacity (GMC)}}$		
5	SF	SERVICE FACTOR	%	F5.2
		$SF = \frac{\text{Service Hours (SH)}}{\text{Period Hours (PH)}} \times 100$		
6	AF	AVAILABILITY FACTOR	%	F5.2
		$AF = \frac{\text{Available Hours (AH)}}{\text{Period Hours (PH)}} \times 100$		
7	FOR	FORCED OUTAGE RATE	%	F5.2
		$FOR = \frac{\text{Forced Outage Hours (FOH)} \times 100}{\text{Forced Outage Hours (FOH)} + \text{Service Hours (SH)}}$		
8	UOR	UNPLANNED OUTAGE RATE	%	F5.2
		$UOR = \frac{\text{Forced Outage Hours (FOH)} \times 100}{\text{Unplanned Outage Hours (UOH)} + \text{Service Hours (SH)}}$		

*The performance indices definitions follow those developed by the EEI.

PERFORMANCE INDICES (13 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
9	POR	PLANNED OUTAGE RATE	%	F5.2

$$POR = \frac{\text{Planned Outage Hours (POH)} \times 100}{\text{Period Hours (PH)}}$$

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
10	EAF	EQUIVALENT AVAILABILITY FACTOR	%	F5.2

$$EAF = \frac{\text{Available Hours (AH)} - \text{Equivalent Partial Planned Outage (EPPOH)} - \text{Equivalent Partial Unplanned Outage (EPUOH)}}{\text{Period Hours (PH)}}$$

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
11	EFOR	EQUIVALENT FORCED OUTAGE RATE	%	F5.2

$$EFOR = \frac{\text{Forced Outage Hours (FOH)} + \text{Equilvalent Partial Forced Outage Hours (PFOH)}}{\text{Forced Outage Hours (FOH)} + \text{Service Hours (SH)}}$$

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
12	EUOR	EQUIVALENT PLANNED OUTAGE RATE	%	F5.2

$$EUOR = \frac{\text{Unplanned Outage Hours (UOH)} + \text{Equivalent Partial Unplanned Outage Hours (EPUOH)}}{\text{Unplanned Outage Hours (UOH)} + \text{Service Hours (SH)}}$$

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
13	EPOR	EQUIVALENT PLANNED OUTAGE RATE	%	F5.2

$$EPOR = \frac{\text{Planned Outage Hours (POH)} + \text{Equivalent Planned Outage Hours (EPPOH)}}{\text{Planned Outage Hours (POH)} + \text{Service Hours (SH)}}$$

DISPATCHING LAMDAS (4 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	VSCCNO	UNIT NUMBER Unit identification number.		I6
2	LAMDHL	HALF LOAD LAMDA* The relative dispatching positions for the half loading block is reported.		I3
3	LAMD3Q	THREE QUARTER LOAD LAMDA* The relative dispatching position for the three-fourths loading block is reported.		I3
4	LAMDFL	FULL LOAD LAMDA* The relative dispatching position for the full load block is reported.		I3

*In general dispatching lamdas are considered outputs of production simulation programs. However, lamdas are really outputs of dispatching modules and inputs to production modules. The purpose of reporting lamdas is to give the utility the opportunity to report how they expect to dispatch the system.

UNIT DATA (4 Branches)
3rd BRANCH: HYDRO GENERATION & OPERATION
Record 1 of 1

MONTH/QUARTER/YEAR TO DATE HYDRO OPERATION DATA (7 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	VSCCNO	UNIT IDENTIFICATION NUMBER		I6
		Unit identification number.		
2	HMXCAP	MAXIMUM NET CAPACITY	MW	I4
		The maximum capacity in MW of the unit during the reporting period less the auxiliary power required by the unit when operating at maximum capacity.		
3	HMNCAP	MINIMUM NET CAPACITY	MW	I4
		The minimum capacity in MW of the unit during the reporting period less the auxiliary power required by the unit when operating at minimum capacity.		
4	UGGEN	UNIT GROSS GENERATION	MWH	I6
		The total energy generated by the unit.		
5	UNGEN	UNIT NET GENERATION	MWH	I6
		The gross generation less the auxiliary energy required by the unit.		
		PUMPING STATION DATA		
6	PUMPEN	ENERGY USED FOR PUMPING	MWH	I5
		The energy supplied by other units in the system for pumping.		
7	APUMCT	AVERAGE PUMPING ENERGY COST	$/MWH	F6.3
		The average cost of the energy used for pumping in $/MWH to the nearest penny. This is equal to the average cost of the energy consumed by base load fossil units that would be operated at a lower load level if there were no pumping.		

UNIT DATA (4 Branches)
4th BRANCH: FOSSIL/NUCLEAR FUEL CONSUMPTION DATA
Record 1 of 3

FOSSIL UNIT FUEL CONSUMPTION BY FUEL TYPE (18 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	VSCCNO	UNIT IDENTIFICATION NUMBER		I6

Unit identification number

PRIMARY FUEL CONSUMPTION

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
2	PRIFUL	PRIMARY FUEL		I1

The primary fuel used by the unit for generation is reported. Enter one of the following numbers.

1 coal
3 light fuel oil
4 heavy fuel oil
5 natural gas

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
3	PBTUCT	AVERAGE COST OF PRIMARY FUEL CONSUMED	¢/MMBTU	F7.3

The average cost of primary fuel consumed is the weighted average cost per MMBTU of the fuel consumed by the unit during the reporting period. For a fossil fuel it is the weighted average cost of the fuel consumed during the period. If a combination of fuel oils is used for generation, report one of them as primary and the other as secondary. This average cost does not include cost components not allowed in the Virginia fuel clause.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
4	PBTUFL	AVERAGE HEAT CONTENT OF PRIMARY FUEL CONSUMED	BTU/(UNIT)	I5

The weighted average heat content of the primary fuel in BTUs per delivered unit (e.g. BTUs/lb, BTUs/gal., BTUs/MCF).

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
5	PGENFC	FRACTION OF UNIT GENERATION BY PRIMARY FUEL		F5.3

The fraction of the unit's gross generation for the month using the primary fuel.

FOSSIL UNIT FUEL CONSUMPTION BY FUEL TYPE (18 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
6	PFULCN	QUANTITY OF PRIMARY UNIT FUEL CONSUMED	UNIT	I8

The total number of units of primary fuel consumed for generation in tons, barrels, or MCF.

7	PFULCT	TOTAL COST OF PRIMARY FUEL CONSUMED	$	I9

The total cost of the primary fuel consumed for generation in thousands of dollars is reported. This cost does not contain cost components not allowable in the Virginia fuel clause.

ALTERNATE FUEL CONSUMPTION

8	ALTFUL	ALTERNATE FUEL		I1

The alternate or secondary fuel used by the unit for generation is listed. Enter one of the following numbers.

1 coal
3 light fuel oil
4 heavy fuel oil
5 natural gas
0 no alternate fuel used

9	ABTUCT	AVERAGE COST OF ALTERNATE FUEL CONSUMED	¢/MMBTU	F7.3

The average cost of alternate fuel consumed is the weighted average cost per MMBTU of the fuel consumed by the unit during the reporting period. For a fossil fuel it is the weighted average cost of the fuel consumed during the period. This average cost does not include cost components not allowed in the Virginia fuel clause.

10	ABTUFL	AVERAGE HEAT CONTENT OF ALTERNATE FUEL CONSUMED	BTU/UNIT	I5

The weighted average heat content of the alternate fuel in BTUs per delivered unit (e.g. BTUs/lb, BTUs/gal, BTU/MCF).

FOSSIL UNIT FUEL CONSUMPTION BY FUEL TYPE (18 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
11	AGENFC	FRACTION OF UNIT GENERATION BY ALTERNATE FUEL The fraction of gross generation using the alternate fuel. For mixtures of fuel oil this would be the fraction of the alternate fuel in the mixture.		F5.3
12	AFUNCN	QUANTITY OF ALTERNATE FUEL CONSUMED The total number of units of the alternate fuel consumed for generation in tons, barrels, MCF.		I8
13	AFULCT	TOTAL COST OF ALTERNATE FUEL CONSUMED The total cost of the alternate fuel consumed for generation is reported. This cost does not contain cost components not allowable in the Virginia fuel clause.	$	I9
		IGNITION FUEL USAGE		
14	IGNFUL	TYPE OF IGNITION FUEL CONSUMED The ignition fuel is that fuel used for ignition or start up. Enter one of the following numbers: 3 light fuel oil 4 heavy fuel oil 5 natural gas 0 no ignition fuel used		I1
15	IBTUCT	AVERAGE COST OF IGNITION FUEL CONSUMED Report the weighted average cost of ignition fuel consumed during the reporting period. This cost does not include cost components not allowed in the Virginia fuel clause.	¢/MMBTU	F7.3
16	IBTUBN	NUMBER OF BTUs NECESSARY TO IGNITE UNIT The number of BTUs required to bring the unit to a state where generation takes place is reported here.	MMBTU	I6

FOSSIL UNIT FUEL CONSUMPTION DATA BY FUEL TYPE (18 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
17	IGNNUM	NUMBER OF UNIT IGNITIONS The number of times the unit was started during the reporting period.		I3
18	IFULCT	TOTAL COST OF IGNITION FUEL CONSUMED The total cost of fuel used to start the unit is reported. This cost does not contain cost components not allowable in the Virginia fuel clause.	$	I7

NUCLEAR UNIT FUEL CONSUMPTION (25 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	VSCCNO	UNIT IDENTIFICATION NUMBER		I6
		Unit identification number		
2	FEAMRT	FRONT END AMORTIZATION	$	I9
		Front end cost amortization is the amortization of the costs of mining, milling, conversion, enrichment, fabrication, and transportation, plus the associated carrying costs. The amortization is associated with the consumption of nuclear fuel in the unit's core during the reporting period.		
3	BEAMRT	BACK END AMORTIZATION	$	I9
		Back end cost amortization is the amortization of the costs of reprocessing and waste disposal less salvage value. The amortization is associated with the consumption of nuclear fuel in the unit's core during the reporting period.		
4	TOTAMR	TOTAL AMORTIZATION	$	I9
		Total amortization is the sum of front end amortization and back end amortization.		
5	NCLCC	LEVELIZED CARRYING COST	$	I9
		For leased fuel, the levelized carrying costs are composed of the normalized charges contractually imposed by the terms of the nuclear fuel trust and lease agreements. These costs include the expense portion of AFUDC, administrative fees, commitment fees, interest, taxes and insurance.		
6	NAFUDC	AFUDC	$	I9
		For leased fuel, the allowance for funds used during construction is the net cost for the period of borrowed funds used during construction. This cost is the portion of AFUDC capitalized to nuclear fuel inventories and charged to fuel expense per the general books but not deductible for tax purposes.		

NUCLEAR UNIT FUEL CONSUMPTION (25 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
7	NADFEE	ADMINISTRATIVE FEES	$	I8
		For leased fuel, administrative fees are fees charged by the trustee under the trust agreement for carrying out the duties and obligations of the trust agreement.		
8	NCTFEE	COMMITMENT FEES	$	I8
		For leased fuel, commitment fees under the trust agreement are fees for the future purchases and continued use of nuclear fuels. These fees are amortized on a monthly basis.		
9	NINTER	INTEREST CHARGES	$	I8
		For leased fuel, interest charges are the daily financing charges for the nuclear fuels under the trust agreements.		
10	NTAXS	TAXES	$	I8
		For leased fuel, taxes are the monthly taxes associated with the operations of the nuclear power generation units.		
11	NINSUR	INSURANCE	$	I8
		For leased fuel, insurance is the monthly cost to the utility of insurance coverage. The utility under trust agreements must at its own expense furnish liability insurance with respect to the nuclear fuel to the extent required under the Atomic Energy Act and other regulation.		
12	NOTHER	OTHER CHARGES	$	I8
		For leased fuel, other charges for nuclear fuel use are those fees incident to the lease agreement but excluding the ones mentioned above. It should not include the cost of fuels used for ancillary steam facilities.		

NUCLEAR UNIT FUEL CONSUMPTION (25 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
13	NCLTFC	TOTAL FUEL COST	$	I9

The total fuel cost is the total dollar costs associated with the purchase, lease or any step in the acquisition of nuclear fuel assemblies, which costs are booked as a nuclear fuel expense during the reporting period, including an estimate of net salvage value.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
14	NAVCBT	AVERAGE COST OF NUCLEAR FUEL CONSUMED	¢/MMBTU	F7.3

The average of nuclear fuel consumed is the total amortization of the burn-up for all in-core assemblies divided by the gross heat generation in millions of BTUs.

ANCILLARY STEAM FACILITY

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
15	ALTFUL	ALTERNATE FUEL		

The alternate or secondary fuel used by the unit for generation is listed. Enter one of the following numbers.

1 coal
2 light fuel oil
3 heavy fuel oil
4 natural gas
0 no alternate fuel used

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
16	ABTUCT	AVERAGE COST OF ALTERNATE FUEL CONSUMED	¢/MMBTU	F7.3

The average cost of alternate fuel consumed is the weighted average cost per MMBTU of the alternate fuel consumed by the unit during the reporting period. For a fossil fuel it is the weighted average cost of the fuel consumed during the period. For both fossil and nuclear fuels, this average cost does not include cost components not allowed in the Virginia fuel clause.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
17	ABTUFL	AVERAGE HEAT CONTENT OF	BTU/UNIT	I5

The weighted average heat content of the alternate fuel in BTUs per delivered unit (e.g. BTUs/lb, BTUs/gal., BTUs/MCF).

NUCLEAR UNIT FUEL CONSUMPTION (25 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
18	AGENFC	FRACTION OF UNIT GENERATION BY ALTERNATE FUEL		F5.3
		The fraction of gross generation using the alternate fuel. For mixtures of fuel oil this would be the fraction of the alternate fuel in the mixture.		
19	AFUNCN	QUANTITY OF ALTERNATE FUEL CONSUMED		I8
		The total number of units of the alternate fuel consumed for generation in tons, barrels, MCF.		
20	AFULCT	TOTAL COST OF ALTERNATE FUEL CONSUMED	$	I9
		The total cost of the alternate fuel consumed for generation is reported. This cost does not contain cost components not allowable in the Virginia fuel clause.		

IGNITION FUEL USAGE

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
21	IGNFUL	TYPE OF IGNITION FUEL CONSUMED		I1
		The ignition fuel is that fuel used for ignition or start up. Report 3 light fuel oil 4 heavy fuel oil 5 natural gas 6 no ignition fuel used		
22	IBTUCT	AVERAGE COST OF IGNITION FUEL CONSUMED	¢/MMBTU	F7.3
		Report the weighted average cost of ignition fuel consumed during the reporting period. This cost does not include cost components not allowed in the Virginia fuel clause.		
23	IBTUBN	NUMBER OF BTUs NECESSARY TO IGNITE UNIT	MMBTU	I6
		The number of BTUs required to bring the unit to a state where generation takes place is reported here.		

NUCLEAR UNIT FUEL CONSUMPTION (25 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
24	IGNNUM	NUMBER OF UNIT IGNITIONS The number of times the unit was started during the reporting period.		I3
25	IFULCT	TOTAL COST OF IGNITION FUEL CONSUMED The total cost of fuel used to start the unit is reported. This cost does not contain cost components not allowable in the Virginia fuel clause.	$	I7

NUCLEAR UNIT FUEL INVENTORY, QUANTITY AND COST (29 elements)

This record pertains to nuclear units using company owned fuel. Nuclear fuel is made up of fuel assemblies. The cost of an assembly consists of front end costs, occurring before the assembly is used to generate power, and back end costs, occurring after the assembly is removed from the reactor. Front end costs include the mining and milling of yellowcake, conversion, enrichment, fabrication, transportation and associated carrying costs. In this record, the value of an assembly is the unamortized portion of the front end costs. Back end costs include reprocessing (to separate uranium, plutonium, high level waste and low level waste), transportation and waste disposal. Net salvage value is the estimated future value (discounted to current dollars) of recoverable uranium, plutonium and other nuclear materials less back end costs. The net value of an assembly is the value of the unamortized portion of the front end costs plus the net salvage value.

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
1	VSCCNO	UNIT NUMBER		I6
		Unit identification number		
2	NBINVQ	BEGINNING INVENTORY - QUANTITY		I5
		The beginning inventory quantity is the number of completed assemblies recorded in stock and in the reactor core at the beginning of the reporting period. This classification does not include spent fuel inventory.		
3	NBINXV	BEGINNING INVENTORY - VALUE	$	I8
		The beginning inventory value is the book value of the beginning inventory quantity, based on front end costs only.		
4	NAINVQ	ADDITIONS TO INVENTORY - QUANTITY		I5
		The quantity of additions to inventory is the number of completed assemblies added to stock and to the reactor core during the reporting period.		

NUCLEAR UNIT FUEL INVENTORY, QUANTITY AND COST (29 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
5	NAINVV	ADDITIONS TO INVENTORY - VALUE The value of additions to inventory is the book value of the quantities added to inventory, based on front end costs only.	$	I8
6	NTINVQ	TOTAL INVENTORY IN STOCK AND IN CORE - QUANTITY Total inventory in stock and in core is the sum of the beginning inventory quantity and the quantity of additions to inventory.		I5
7	NTINVV	TOTAL INVENTORY IN STOCK AND IN CORE - VALUE The value of total inventory in stock and in core is the sum of the beginning inventory value and the value of additions to inventory.	$	I8
8	NNSVVN	NET SALVAGE VALUE OF TOTAL INVENTORY The net salvage value of total inventory is the estimated future value (discounted to current dollars) of recoverable nuclear materials less reprocessing costs and less waste disposal costs, assuming that all assemblies in stock and in core are used to the design level of heat generation (burn-up).	$	I8
9	NTINNV	TOTAL INVENTORY - NET VALUE The net value of total inventory is the value of total inventory in stock and in the core plus the net salvage value of total inventory. Note: if net salvage value is negative, the net value will be less than the book value.	$	I8
10	NAMORT	AMORTIZATION OF FUEL BURNED IN REACTOR The amortization of fuel burned in the reactor is the reduction in the net value of inventory assignable to the burn-up of nuclear fuel in the core during the reporting period.	$	I8

NUCLEAR UNIT FUEL INVENTORY, QUANTITY AND COST (29 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
11	NTSFIQ	TRANSFERS TO SPENT FUEL INVENTORY - QUANTITY This classification contains the number of assemblies transferred from the reactor to spent fuel cooling or on-site spent fuel storage facilities during the reporting period.		I5
12	NTSFIV	TRANSFERS TO SPENT FUEL INVENTORY - VALUE This classification contains the value, based on unamortized front end costs, of the transfers to spent fuel inventory.	$	I8
13	NTSFIN	TRANSFERS TO SPENT FUEL INVENTORY - NET VALUE This classification contains the (positive or negative) net value, based on unamortized front end costs plus net salvage value, of transfers to spent fuel inventory.	$	I8
14	ENDINQ	ENDING INVENTORY - QUANTITY The ending inventory quantity is the number of completed assemblies recorded in stock and in the reactor core at the end of the reporting period. This classification does not include spent fuel inventory.		I5
15	ENDINV	ENDING INVENTORY - NET VALUE The ending inventory net value is the net value of the ending inventory quantity.	$	I8
16	NBSFIQ	BEGINNING SPENT FUEL INVENTORY - QUANTITY The beginning spent fuel inventory quantity is the number of assemblies in spent fuel cooling or on-site spent fuel storage facilities at the beginning of the reporting period.		I5
17	NBSFIV	BEGINNING SPENT FUEL INVENTORY - VALUE This classification contains the value, based on unamortized front end costs, of the beginning spent fuel inventory quantity.	$	I8

NUCLEAR UNIT FUEL INVENTORY, QUANTITY AND COST (29 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
18	NBSFIN	BEGINNING SPENT FUEL INVENTORY - NET VALUE	$	I8
		This classification contains the net value, based on unamortized front end costs plus net salvage value, of the beginning net inventory quantity.		
19	NSFLCQ	SPENT FUEL FROM LEASE CONTRACTS - QUANTITY		I5
		This classification contains the number of assemblies acquired under fuel lease contracts and transferred to spent fuel storage at the nuclear unit during the reporting period.		
20	NSFLCV	SPENT FUEL FROM LEASE CONTRACTS - VALUE	$	I8
		This classification contains the value of spent fuel from lease contracts.		
21	NSFLCN	SPENT FUEL FROM LEASE CONTRACTS - NET VALUE	$	I8
		This classification contains the net value of spent fuel from lease contracts.		
22	NRSFIQ	REMOVALS FROM SPENT FUEL INVENTORY - QUANTITY		I5
		This classification contains the number of assemblies removed from spent fuel storage during the reporting period.		
23	NRSFIV	REMOVALS FROM SPENT FUEL INVENTORY - VALUE	$	I8
		This classification contains the value of the removals from spent fuel inventory.		
24	NRSFIN	REMOVALS FROM SPENT FUEL INVENTORY - NET VALUE	$	I8
		This classification contains the net value of removals from spent fuel inventory.		

NUCLEAR UNIT FUEL INVENTORY, QUANTITY AND COST (29 elements)

FIELD NUMBER	ELEMENT NAME	FULL NAME	UNITS	ELEMENT ATTRIBUTE
25	NESFIQ	ENDING SPENT FUEL INVENTORY - QUANTITY		I5
		The ending spent fuel inventory quantity is the number of assemblies in spent fuel cooling or on-site spent fuel storage facilities at the end of the reporting period.		
26	NESFIV	ENDING SPENT FUEL INVENTORY - VALUE	$	I8
		This classification contains the value of the ending spent fuel inventory.		
27	NESFIN	ENDING SPENT FUEL INVENTORY - NET VALUE	$	I8
		This classification contains the net value of the ending spent fuel inventory.		
28	NSFSTC	SPENT FUEL STORAGE CAPACITY		I5
		The spent fuel storage capacity is the number of spent fuel assemblies that can be stored on-site at the unit. (If several units share joint storage facilities, allocate the storage among the units.)		
29	NSFSTR	STORAGE CAPACITY REMAINING		I5
		Storage capacity remaining is the spent fuel storage capacity less the ending spent fuel inventory quantity.		

EXHIBIT A

IDENTIFICATION CODES

Identification codes for electric utility companies are established by the Commission.

Identification codes for plants are those used in FERC Form 423.

Identification codes for units are established by the Commission. An example of the unit code is given in Table A-1.

Identification codes for fuel suppliers are established by the reporting company and supplied to the Commission along with the name and address of each supplier.

Identification codes for modes of transportation are given in Table A-2.

Identification codes for intersystem sales and purchases are given in Table A-3.

Table A-1 Example of the Six Digit Generation Unit Identification Code for the Virginia Electric and Power Company

Digit 1	Company Name:	
	(5) Vepco	
Digits 2 & 3	Plant Name:	
	(01) Bremo	(08) North Anna
	(02) Chesterfield	(09) Kitty Hawk
	(03) Mt. Storm	(10) Lowmoor
	(04) Portsmouth	(11) Northern Neck
	(05) Possum point	(12) Gaston
	(06) Yorktown	(13) Roanoke Rapids
	(07) Surry	
Digit 4	Type of Generation:	
	(1) Steam-Fossil	
	(2) Steam-Nuclear	
	(3) Combustion Turbine (I.C.)	
	(4) Gas Turbine	
	(5) Jet Engine	
	(6) Hydro-Run of River	
	(7) Pumped Storage	
	(8) Hydro-River Storage	
Digits 5 & 6	Individual Generating Unit Numbers	

Table A-2 Transportation Mode Codes

01	Barge
02	Truck
03	Conveyor Belt
04	Pipeline
05	Train - Unit Train
06	Train - Volume Rate
07	Train - Single Car Rate
08	Train - Utility Owned
09	Combination of Above

Table A-3 Identification Codes for Intersystem Sales and Purchase*

CODE	DESCRIPTION/DEFINITION
01	Firm Contract
02	Economic Power -- economy energy (interchange accounted for on a monetary basis. Has no associated demand or capacity costs.)
03	Purchased Power -- emergency (interchange accounted for on a monetary basis. Not considered as system capacity.)
04	Economic Power -- other than economy energy
05	Short Term Purchased Power
06	Limited Term Purchased Power
07	Unit Power Purchased (not considered as system capacity)
08	Nuclear Power -- purchased
09	Interchange -- power in (borrowed; when there is no payment or financial settlement)
10	Transmission of Electricity of Others (wheeling)
11	Firm Contract Sales for Resale to Electric Utility
12	Sale of Power -- economy energy (interchange accounted for on a monetary basis)
13	Sale of Power -- emergency (interchange accounted for on a monetary basis)
14	Special Contract Sales to Ultimate Consumers with Fuel Charge per kWh Same as Jurisdictional Allowable Charge Per kWh
15	Special Contract Sales to Ultimate Consumers with Fuel Charge per kWh Higher than that Normally Allowed.
16	Nonjurisdictional Sales to Ultimate Consumers (not special contracts) with Fuel Charge per kWh Same as Jurisdictional Allowable Charge per kWh
17	Nonjurisdictional Sales to Ultimate Consumers (not special contracts) with Fuel Charge per kWh Higher than that Normally Allowed.
18	Jurisdictional Sales to Ultimate Consumers

*Adapted from ID codes used by the Public Utilities Commission of Ohio.

Table A-3 Identification Codes for Intersystem Sales and Purchase (continued)

CODE	DESCRIPTION/DEFINITION
19	Interchange -- power out (loaned; when there is no charge or financial settlement)
20	Sales for Resale Other than to Electric Utility
21	Special Contract Sales to Ultimate Consumers with Fuel Charge per kWh Lower than that Normally Allowed
22	Nonjurisdictional Sales to Ultimate Consumers (not special contracts) with Fuel Charge per kWh Lower than that Normally Allowed
23	Short Term Power Sold for Resale
24	Limited Term Power Sold for Resale
25	Unit Power Sold for Resale
26	Nuclear Power Sold for Resale that is Identified with a Nuclear Generating Unit
27	Other Power Sold for Resale
28	Intersystem/Intrasystem Ultimate Consumer Sales Accounted for on a Monetary Basis with Fuel Charge per kWh Greater than or Equal to that Normally Allowed
29	Special Contract Sales to Ultimate Consumers with Fuel Charge per kWh Lower than that Normally Allowed
30	Intersystem Sales for Resale Accounted for on a Monetary Basis and/or Sales for Resale to Intrasystem Pool
31	Special Contract Sales to Ultimate Consumers with Fuel Charge per kWh Higher than that Normally Allowed
32	Intersystem/Intrasystem Ultimate Consumer Sales Accounted for on a Monetary Basis with Fuel Charge per kWh Less than that Normally Allowed
33	Transmission of Electricity of Others (wheeling) -- out