FEDERAL ENERGY REGULATORY COMMISSION

Final Report

Incentive Regulation in the Electric Utility Industry: Volume 2

September 1983

8.

INCENTIVE REGULATION IN THE ELECTRIC
UTILITY INDUSTRY: VOLUME II

Final Report

Contract No.: DE-AC39-82RC-11845

RCG No.: RA83-0143

Prepared for:

Federal Energy Regulatory Commission
825 North Capitol Street
Washington, DC 20426

Prepared by:

Resource Consulting Group, Inc.
1000 Massachusetts Avenue
Cambridge, MA 02138

Principal Investigators:

Dennis Goins, Hagler, Bailly & Company
Michael Fisher, Hagler, Bailly & Company
Robert Smiley, Cornell University
Jerome Hass, Cornell University
Ronald Ehrenberg, Cornell University

Contents

Introduction

On October 15, 1982, Resource Consulting Group, Inc. (RCG), submitted a draft report to the Federal Energy Regulatory Commission (FERC) titled, Incentive Regulation in the Electric Utility Industry.* The FERC distributed the draft report to more than 60 individuals and organizations who were requested to review and comment on the various proposals and recommendations outlined in the report. In response to the FERC's request, 18 organizations submitted formal review comments. A list of these reviewers is shown in Exhibit 1.

In the draft and final report to FERC, we recommended three major incentive programs:

1. Rate Control Incentive Program (RCIP), which incorporates a unit cost index as a measure of utility performance and a ratepayer-funded incentive award payment that would be distributed by a utility to its key managers. A utility would earn an incentive award payment if its cost performance exceeded the average performance of other utilities in its comparison group.

2. Construction Cost Control Incentive Program (CCIP), which links an incentive rate of return on equity to a utility's cost performance in constructing major investment projects such as baseload generating plants.

3. Automatic Rate Adjustment Mechanism (APAM), which links adjustments to cost elements

---

*The final version of this report has been submitted to FERC under the title, Incentive Regulation in the Electric Utility Industry: Volume I.

Exhibit 1

REVIEWERS OF DRAFT REPORT

Organization	Reviewer
1. Advanced Information & Decision Systems	Darrell D. Freeman, Senior Research Engineer
2. American Electric Power Service Corporation	David H. Williams, Jr., Senior Vice President-Operations
3. American Public Power Association	John Kelly, Staff Economist
4. California Public Utilities Commission	Barbara Barkovich, Director, Policy and Planning Division
5. Carolina Power & Light Company	Samuel Behrends, Jr., Vice President-Corporate Regulatory Policy
6. Charles River Associates, Inc.	George R. Hall, Vice President
7. Edison Electric Institute	Douglas C. Bauer, Senior Vice President
8. Energy Research Group	John H. Landon, Vice President, National Economic Research Associates, Inc.
9. Florida Power & Light Company	B.L. Dady, Vice President, Management Control and Services
10. Florida Public Service Commission	Joseph P. Cresse, Commissioner
11. Iowa State Commerce Commission	Enver Masud, Director, Operations Review Division
12. Merril, Lynch, Pierce, Ferner & Smith, Inc.	Leonard S. Hyman, Vice President
13. National Regulatory Research	Kevin Kelly, Steve Henderson, William Pollard
14. Ohio Consumer's Counsel	Timothy C. Jochim, Associate Consumers' Counsel
15. Southern Company Services	Donald R. Wells, Manager, Compensation and Benefits Department
16. Virginia Electric & Power Company	William W. Berry, President & Chief Executive Officer
17. Wisconsin Electric Power Comany	Richard A. Abdoo, Vice President, Corporate Planning
18. Wisconsin Public Service Commission	Stanley York, Chairman

recovered in a utility's rates to changes in external cost indexes for those cost elements.

Before proceeding with the discussion of the reviewers' specific comments on each of these recommended programs, several general points should be made. We reviewed all of the comments several times and discussed them among our project team members. On the basis of these reviews and discussions, we reached general conclusions in the three areas described below.

1. Objectives of the Recommended Programs. Most of the reviewers failed to perceive, chose to ignore, or rejected out-of-hand the two key underlying objectives that we tried to incorporate in each of the recommended programs. The first objective is to remove regulatory commissions from the role of shadow managers of electric utilities. This shadow manager role is demonstrated in part by existing incentive mechanisms that focus on subaggregate performance (e.g., heat rate and availability standards); after-the-fact review and judgment of utility investment programs; and the seemingly unending regulatory oversight of day-to-day utility operations (e.g., fuel procurement and utilization practices). Stronger critics of current regulatory practices than we might even argue that it is impossible to distinguish the shadow managers from the real managers of electric utilities in some states.

The second objective is to direct incentives at those agents of the firm who can most directly affect a utility's performance. Because the managers are principal determinants of corporate performance measured either by rates charged to customers or by returns earned by shareholders, utility management should receive direct incentives to improve corporate performance or to maintain existing high levels of performance. Whether these incentives come from programs such as the RCIP initiated by regulators or from management incentive compensation programs initiated by utilities may be immaterial from the standpoint of ratepayers and possibly even shareholders.

Regulators, in their role as shadow managers, often ignore the importance of utility management by mandating performance standards and then linking realized performance to rewards or penalties that are initially reflected in potential returns to shareholders (e.g., failure. Contrary to these overstated and unsubstantiated assertions, we contend that minor deficiencies that might exist after further development of the RCIP would, in all likelihood, be acceptable to the majority of regulators, ratepayers, utility managements, and shareholders.

On the other side of the fence, we also perceived a lack of strong support for the RCIP from regulatory and consumer-related organizations. As we noted in Volume I, the thrust of incentive program development by regulatory commissions today is toward the establishment of subaggregate level performance standards. Although we and a number of the draft report's reviewers are convinced that incentives based on subaggregate level performance are inappropriate, convincing most regulators and consumer advocates on this point will be quite difficult.

Without strong support for the RCIP from electric utilities, state regulators, and consumers, it is reasonable to ask whether FERC should pursue development of the RCIP along the lines we recommended in Volume I and elaborated on in Item 2 above. In our opinion, FERC should move ahead with development of the RCIP, as well as the CCIP and ARAM incentive regulation programs. Any incentive program that creates major changes in the focus and application of regulation will be met with loud protests from parties with diverse interests. However, major changes in regulation are required to ensure that electricity will be available in the future to ratepayers at reasonable cost and that investors will continue to be willing to put up the capital required to develop an adequate supply of electricity. Our recommended programs, or similar programs that FERC might initiate, offer the potential for effecting these required changes.

The remainder of Volume II is organized as follows. In Chapter 1, we present our responses to the reviewers' comments on specific aspects of our recommended incentive regulation programs. The complete text of each reviewer's comments is presented in Appendix A.

1 RCG RESPONSES TO COMMENTS ON RECOMMENDED INCENTIVE REGULATION PROGRAMS

In the following sections, we present responses to comments on specific aspects of the three recommended incentive regulation programs. We have grouped responses concerning the RCIP by major issue (e.g., how should performance be measured) instead of attempting to respond in detail to the comments of each reviewer. The interested reader can identify the reviewer(s) to whom our responses are directed by reading the comments presented in Appendix A.

RATE CONTROL INCENTIVE PROGRAM

The RCIP contains three performance measures, including a:

- Static measure based on a utility's weighted average revenue per kWh over a 5-year period.
- Dynamic measure based on the rate of change in a utility's rates over two static measurement periods.
- Rate Performance Index (RPI), which represents a weighted combination of the static and dynamic performance measures.

Reviewers of the draft report commented at length on several important aspects of the RCIP's procedures for measuring and evaluating utility performance. In the following sections, we discuss comments that were offered on the following seven aspects of the RCIP:

- Choice of an aggregate focus.
- Choice of revenue per kWh as a measure of performance.

- Specification of the time period over which performance is measured.
- Selection of static and dynamic performance measures.
- Evaluation by comparing a firm's performance with that of other firms.
- Development of weights for combining measures of static and dynamic performance.
- Regulatory involvement in management incentive compensation programs.

Choice of an Aggregate Focus

Reviewers generally agreed with our recommendation that an aggregate measure of performance should be the focus of an incentive program to prevent biases in management's decision framework concerning the combination of factor inputs. However, some reviewers, particularly representatives of state regulatory commissions, argued that an aggregate focus should be combined with subaggregate measures of performance. While we believe that the study of subaggregate performance may provide useful insights to management and regulators in understanding how production process characteristics are changing over time, or how they differ among utilities, we continue to argue against the use of subaggregate measures as the focus of an incentive program.

Choice of Revenue Per kWh as a Measure of Performance

Several reviewers cited potential difficulties in using revenue per kWh as a measure of performance. These perceived difficulties ranged from accounting for factors beyond management's control (see our comments on interutility comparisons below) to the possibility of conflicts of interest between management and shareholders under the RCIP. For example, several reviewers cited the lack of uniform accounting rules among utilities and regulatory jurisdictions that might participate in the program. Other reviewers indicated that utilities might be able to "game the system" by altering their accounting procedures to delay the accrual of costs to ratepayer accounts. Some argued that utility managers would be encouraged to forego costly capital additions that would have long-term economic benefits, but which would cause short-term rate increases. Our response to these comments is that with a sufficiently long period for measuring performance (i.e., 5-10 years), managers will not benefit by accounting tricks nor will they be encouraged to defer large, but economically beneficial, capital projects.

Some reviewers also indicated that the lack of detailed, consistent accounting for off-system sales would limit the comparability of the performance measure across firms. We agree that improved specificity in the accounting procedures for off-system sales would make interutility performance comparisons more reliable. Moreover, FERC should be able to develop accounting guidelines for off-system sales that would not be administratively burdensome.

Reviewers also argued that the use of revenue per kWh as a performance measure, coupled with a compensation-based incentive mechanism, would create a conflict of interest between management and shareholders. That is, management might be encouraged to seek a low rate of return on equity or low rates generally as a means of receiving an incentive award, despite the consequences to shareholders. As we discussed in Volume I, one approach to avoiding this problem is to exclude a firm's chief excecutive officer and his selected staff from the incentive bonus system. The firm's CEO and his selected staff would be responsible for ensuring that shareholder interests received adequate attention in the ratemaking process. A second consideration to bear in mind is that with a sufficiently long averaging period (i.e., 5-10 years) for measuring performance, actions by managers to squeeze rates in one or two years should have little effect in improving a firm's apparent performance.

An additional concern expressed by some reviewers is that firms would be encouraged to reduce quality of service. As we discussed in Volume I (see Volume I, pages 2.10-2.11), we recommend adjusting the measure of revenue per kWh for the cost to consumers of energy not served due to losses of service. Alternatively, regulators could develop oversight and review procedures to determine whether a utility's quality of service was adequate.

Specification of the Performance Measurement Time Period

Some reviewers contended that our recommended 5-year averaging period was too brief to ensure that management would be adequately attentive to the benefits of long-lived capital investments. We agree and emphasize that in the draft report we argued for a measurement period of at least 5 years (see Volume I, page 2.12) and did not conclude that 5 years is the optimum period for measurement.

Selection of Static and Dynamic Performance Measures

Most reviewers agreed that measuring both static and dynamic performance is desirable. However, several reviewers recommended against measuring static performance on an absolute basis. These critics contend that too many factors beyond management's control (e.g., abnormal weather conditions) could affect the absolute measure and thereby distort comparisons of a firm's relative performance. We agree in principle that such distortions could occur, especially if static performance were measured only for a one-year period. However, we are not convinced that such potential distortions are a serious problem under the 5-year (or longer) period on which our recommended static measure is based.

Evaluation Procedures Using Interutility Comparisons

Most reviewers did not fundamentally opppose our recommendation that performance be evaluated by comparing a firm's performance with that of other, similar firms. However, several reviewers questioned the ability to form comparable groups of utilities as a basis for evaluating performance. These critics argued that the incentive program administrators would not be able to account adequately for all factors beyond management's control in forming comparison groups and that groups would be too heterogeneous.

We recognize that the formation of comparison groups would perhaps be the most difficult and contentious aspect of implementing our proposed incentive regulation program. However, the anticipation of difficulty should not preclude efforts to study further this incentive option. Because of study scope limitations, we were unable to explore in-depth all of the possible approaches for forming comparison groups. We are not convinced by the arguments of the reviewers that this would be an impossible task or that it would be always rejected by utilities. In fact, we are aware of at least 5 major U.S. utilities that have embodied inter-firm comparisons in an internally developed performance evaluation process. Rather than accept the cursorily developed rejection of the concept exhibited in the comments of some reviewers, we recommend that FERC undertake further work on the subject to evaluate alternative methods of developing comparable utility groups.

Several reviewers also criticized our list of attributes by which firms would be characterized in forming comparison groups. These reviewers argued that we did not include all factors that could influence firm performance. We did not intend our list to be exhaustive or final and would readily accept additional classification criteria. Similarly, some reviewers criticized our recommendation that past management decisions regarding the level and mix of capacity not be reflected in establishing performance evaluation groups. As we indicated in the draft report, (see Volume I, pages 2.17-2.18), we recognize that firm characteristics that result from past management decisions can be used as a basis for grouping firms. However, because the recognition of past decisions weakens the incentive effect of the performance evaluation procedure, we prefer excluding firm characteristics that reflect past management decisions.

Development of Weights for Combining Measures of Static and Dynamic Performance

In the draft report, we recommended a procedure for combining separate measures of static and dynamic performance into a single index of performance (i.e., the RPI). This procedure involves weights for the separate indexes of static and dynamic performance that vary according to a firm's measure of static performance. That is, a firm with good static performance would receive a high weight on its static performance measure and a low weight on its dynamic performance measure. Conversely, a firm with poor static performance would receive a low weight on static performance and a high weight on dynamic performance.

Several reviewers indicated that our recommended weighting procedure would cause firms on average to receive a positive index score and be eligible for an incentive award. We recognize this possible result and offer two methods for resolving the bias. One method would be to calculate the composite performance index for a large sample of firms over several years, and to calibrate the average index score to zero. In this way, on average, a firm would neither receive a positive nor negative index score. A second method to correct the bias would be to abandon the variable weights in favor of a fixed weight scheme. In this case, at least one reviewer recommended that the weights not be equal and that a higher weight be given to the static performance scores.

Several reviewers indicated that any procedure for combining the separate static and dynamic index scores would be arbitrary. We recognize that the final determination of a scoring procedure will be arbitrary (i.e., why should weights be 0.5 and 0.5 instead of 0.45 and 0.55?). However, such a conclusion certainly does not warrant rejection of the concept. In fact, the weighting scheme that would evolve under the RCIP would have to reflect a general concensus among utilities and regulators about the relative importance of static and dynamic performance. Moreover, a weighting scheme selected in this manner would be no more arbitrary than many other aspects of the regulatory process (e.g., selecting an allowed return on equity from within a range of 13.8 and 15.5 percent).

Regulatory Involvement Management Incentive Compensation Programs

Although management incentive compensation programs are not widespread in the electric utility industry,* a trend toward the adoption of such programs appears to be developing in the industry. And with this trend,

*See Volume I, Appendix G for descriptions of management incentive compensation programs in three utilities.

utilities will increasingly have to deal with regulatory involvement in management compensation. Such regulatory involvement, which is also created under the recommended RCIP, was strongly criticized by several reviewers. However, in our opinion, the regulatory involvement required under the RCIP is quite minimal compared to the increasing scrutiny that utilities with management incentive compensation programs can expect from regulators concerning whether ratepayers should bear the total cost of the programs. More specifically, incentive awards under most management incentive compensation programs in electric utilities are funded by ratepayers (i.e., the cost of incentive awards are typically included in labor expenses for ratemaking purposes). Unless utilities elect to fund these programs from after-tax earnings (as calculated for ratemaking) supplied by shareholders,* they face the almost certain prospect of having regulators refuse to pass some or all of the cost of such incentive awards through rates on the basis of poor utility performance measured on an absolute or relative basis. Utilities, therefore, appear to have only one option for avoiding regulatory involvement in management incentive compensation programs, even if FERC never implements the RCIP. And choosing to exclude the cost of management incentive compensation awards from rates is no guarantee that regulators will drop their direct, and often ill-advised scrutiny of management compensation, as well as other subaggregate aspects of utility operations.

CONSTRUCTION COST CONTROL INCENTIVE PROGRAM

The CCIP is an incentive program that affects a firm through incremental adjustments to the allowed rate of return on the cost of power plant construction that is included in rate base. The CCIP has two major objectives:

- Establish a system whereby regulators work with utilities on a prospective basis to assess the need for and projected cost of major generating plants. Such a system would certainly lessen the ability of regulators to justify after-the-fact penalties and mismanagement charges

*At least one major utility has chosen this option.

against utilities that construct facilities that may be completed significantly above budget or that temporarily create excess capacity.

- Create a set of prospective incentives for utility management to assess on a realistic basis the potential risks to both shareholders and ratepayers associated with investments in major power plant projects.

The need for the CCIP, or a similar program, is demonstrated by two factors. The first is the growing tendency for regulatory commissions to resort to 20/20 hindsight in reviewing the need for and cost of newly constructed power plants. The second is the seeming inability of many utilities to complete construction of baseload generating units within a reasonable range of initially projected construction costs (including adjustments for inflation). Consider what would happen if management in a nonregulated business undertook high-risk projects, failed to complete construction of the projects within any reasonable range of the original cost estimates, and, as a result, created serious dilution in the book value and earnings power of the company's stock. The company's shareholders, in all likelihood, would probably force the board of directors to fire several top managers. But these actions have not occurred in the electric utility industry. (For a suggested reason, see our comments on the link between shareholders, the board of directors, and management in the discussion of the RCIP). Instead, we have regulators blaming cost overruns and excess capacity on utilities and utilities blaming these problems on regulatory burdens and inflation. The CCIP would represent a possible means of resolving these disputes before they occur.

Despite the potential benefit of the CCIP, the majority of reviewers commenting on the program recommended against its implementation by FERC. Most of their criticisms focused on potential problems that were explicitly recognized in the draft report. These include the potential for the program to bias management against capital intensive, high-risk investments; create incentives for management to inflate initial cost estimates; and increase the firm's cost of capital. We contend that a properly structured and operated CCIP can deal effectively with the first two problems, and if the program is administered fairly, the potential for increasing a firm's cost of capital will be minimized.

Another major criticism focused on the "exceedingly cumbersome" nature of the CCIP. Our response is that when a utility undertakes a construction program that may double or triple its rate base and supply the bulk of its future baseload power requirements, more than a cursory examination of the program by regulators can be justified. In addition, contrary to the implicit assumption contained in one reviewer's comments that utilities may not be "as motivated by financial rewards as the authors assume,"* we offer the following. If a utility's management puts the requirement to serve ratepayers above the interests of shareholders, that management should be removed by its shareholders. Shareholders own the company, and management's primary responsibility is to protect the interests of its shareholders while serving the company's ratepayers. Part of this responsibility certainly includes adhering to groundrules (e.g., obligation to serve) laid out by regulators and lawmakers for receiving and retaining a service area franchise. However, meeting these groundrules can be achieved in a number of ways, some of which may not appear to be least-cost investment strategies as measured by existing capacity planning models and procedures. And the CCIP, instead of simply biasing investments against capital intensive, high-risk projects that appear to achieve a least-cost electricity supply for ratepayers, may finally cause utility managers to reflect in their planning models and procedures the cost of potential risks to shareholders.

AUTOMATIC RATE ADJUSTMENT MECHANISM

Most comments on the ARAM were favorable. On the basis of these comments, we recommend that FERC undertake additional work to develop solutions to the problem areas highlighted in our discussion of the ARAM in Volume I and in the reviewers' comments in Appendix A.

---

*See the comments of the Energy Research Group, p. 52.

Appendix A

In this appendix, we present the comments submitted by organizations who reviewed the draft report.

AI&DS
ADVANCED INFORMATION
& DECISION SYSTEMS

201 San Antonio Circle, Suite 286
Mountain View, CA 94040-1270
(415) 941-3912

January 10, 1983

Dr. Bernard Tenenbaum
Acting Chief
Economic Analysis Branch
Office of Regulatory Analysis

Ref: Draft Report
Contract No: DE-AC39-82RC-11849
RCG No: RA82-0143

Dear Dr. Tenenbaum:

I have reviewed the reference draft report prepared by RCG, Inc. The report addressed the implementation of incentives by FERC to improve the efficiency of the electric utility industry. In my opinion, the report does not provide an adequate basis for implementing an incentive program.

The report makes a recommendation favoring the application of direct performance incentives to utility managers based on cost of service. A further recommendation would have performance measured against other utilities. These recommendations are supported by arguments describing supposed behavior of utility management under the recommended program. The intent of the measurement recommendation is to simulate a competitive environment for the managers.

In my opinion the RCG recommendations are unsound. Neither the incentives themselves nor the method of evaluation are shown to provide minimum cost of service. Furthermore, the recommendation creates an added administrative burden on the regulator to manage the incentives and involves the regulator in the compensation of the utilities employees. On the face of it this would seem to create a potential conflict of interest for the utility managers. Finally, the recommendation leaves the utility shareholders out of the picture. They neither benefit nor suffer and consequently become even less involved in directing the utility business.

The concept of measuring one utility against another on the basis of overall cost of service presents many difficulties. Utilities offer a variety of services to a variety of customers. Cost factors would have to be analyzed on a customer by customer basis and then aggragated and adjusted period by period to have a fair basis of comparison. One utility may be a net seller of power, another may provide primarily transmission and distribution services. The operational problems, the cost factors and the risk factors may vary significantly from one utility to another. It is not clear that utility managers

Comments of Draft RA82-0143

CH.2 Selecting the Focus of An Incentive Program

Based on our analysis, the recommended focus is inappropriate and the supporting arguments are invalid.

Our analysis shows that incentives must be designed for the individual operating units to be effective. Furthermore, we show that this may be done by the regulator without detailed knowledge of the utility operations. Our incentive formula produces maximum benefits to be shared between shareholders and rate payers and allocates cost, risk and benefits in the same proportion. Our approach takes advantage of the profit maximizing behavior of the utility.

Developing Procedures for Measuring Performance of a Firm:

Several elements of risk and uncertainty are neglected in the discussion. Risk management should be a principal occupation of utility management. Effects of variable load, variable weather, variable resources e.g. hydro and purchased power, have not been discussed.

Our analysis shows that minimizing the price, as recommended by the RCG study, will not produce optimal performance. The effective price in a period includes adjustments for revenue transfer from one operating period to another. Maximizing total effective benefits, through incentives, is consistant with the profit maximizing behavior of the utility, and produces optimal system operation.

Comparison of firms at the cost of service level does not adjust for significant differences in generation mix, load characteristics, geography, weather, age of equipment, rate of growth, etc., etc., etc. It is not clear why passing out rewards or penalties on this basis will be productive in any way.

Ch. 3 Selecting the Focus of the Mechanism:

The report recommends direct compensation to utility management for good performance. This will involve regulators in direct intervention between utility managers and shareholders, and create conflict of interest situations for the management.

The basic notion of fostering a competative environment for utility executives is not well founded. In one sense the competition already exists between net buyers and sellers of power. In another sense the recommended approach usurps the rights of utility shareholders. You don't train an elephant to behave like a zebra by painting stripes on it. Neither do you get a monopoly to behave like a competitive firm by intervention between shareholders and managers.

Our analysis shows that the basic result of free market operation, maximum total benefits, can be achieved through incentives, within the existing regulatory frame work.

will operate as if they are in a competitive environment, nor is it clear that this is a desirable behavior to induce. How, for example, would you prevent collusion by a group against another utility?

In short, I question both the assumptions and the analysis which supports the RCG recommendation. My comments on various sections of the report are enclosed. These comments are influenced by the work we have done in this area.

Our analysis of incentive regulation leads to a formula for setting incentives at the functional level e.g. each operating unit has its own set of incentives. We show that this is necessary to achieve maximum benefits and that any incentives not satisfying this criteria will achieve less than maximum benefits. Furthermore, we show that these incentives may be set using only high level information about the utility operations. Our approach is described in the enclosed paper. Since our work in this area has been supported completely by AI&DS, I must ask you to treat this paper as proprietary information at this time.

Thank you for the opportunity to review the RCG work. I hope my comments are helpful to you. I will call you soon to discuss a feasibility study for implementing the type of incentives as described in our paper.

Very truly yours,

Darrell Freeman

Darrell D. Freeman
Senior Research Engineer

DDF:rjp
encl.

AMERICAN ELECTRIC POWER *Service Corporation*

AEP

P. O. Box 487, Canton, Ohio 44701
(216) 452-5721

DAVID H. WILLIAMS, JR.
Senior Vice President
Operations

February 8, 1983

Dr. Bernard Tenenbaum
Acting Chief
Economic Analysis Branch
Office of Regulatory Analysis
Federal Energy Regulatory Commission
Washington, D. C. 20426

Dear Dr. Tenenbaum:

The following is in reference to your letter of December 7, 1982, and the draft report prepared by the Resource Consulting Group, Inc., for FERC. We found the report most interesting and appreciate your sending us a copy for review and comment. The main thrust of the report appeared to be incentives to produce power at the lowest possible cost to the customer. The management of the American Electric Power System has for a long time been strong believers in the policy of producing low cost power for its customers. The incentive program we initiated in 1979 as described in the report was directed at improved power plant availability and efficiency on a cost-effective basis.

We question whether the incentive program proposed in the report would be understood or accepted by the state regulatory commissions. Of the seven states serviced by the AEP System, only one state commission staff has expressed any interest in comparing Company performance against other utilities. We would also prefer handling internally the evaluation and compensation of our management rather than through some form of a performance bonus determined by a regulatory commission.

In summary, we found the report of interest and fully support the intent. We believe performance should be recognized by the commission in setting the allowed rate of return rather than in the form of a bonus granted by the commission to selected management personnel.

Very truly yours,

David H. Williams, Jr.

David H. Williams, Jr.

/d

cc: John E. Dolan

AMERICAN PUBLIC POWER ASSOCIATION

2301 M STREET NW WASHINGTON DC 20037 • 202/775-8300

March 3, 1983

Dr. Bernard Tenenbaum
Acting Chief,
Economic Analysis Branch
Office of Regulatory Analysis
Federal Energy Regulatory Commission
Washington, D.C. 20426

Dear Dr. Tenenbaum:

Thank you for giving APPA the opportunity to comment on "Incentive Regulation in the Electric Utility Industry," a study prepared for the FERC by Resource Consulting Group (RCG). Mr. Radin has asked me to prepare comments on the report for him. Because of the study's length, I have, as you suggested, confined our comments to those parts of the report that are of most interest to the APPA. However, I have taken the time to review the entire study and disagree with several other areas of the report.

The study's general recommendation that the FERC initiate steps to implement a comprehensive program designed to encourage utilities to maintain the lowest possible rates to consumers is a laudable one with which I agree, but the particular program recommended by the study is untested and theoretically unsound, and, consequently, its results are uncertain.

The primary objective of what the study calls its "rate control incentive program" is to encourage each jurisdictional utility "to reduce the level of and growth in its electricity rates relative to that of other comparable utilities." The mechanism through which utilities will supposedly be encouraged "to reduce rates is the payment of incentive awards to those utilities that reduce the level and growth in their rates relative to comparable firms."

I see numerous practical problems with this approach. Just the grouping of comparable firms would be difficult, as the study itself suggests. But more important, focusing on a single formula, as the study does, for determining the relative efficiency of management performance is likely to produce unfair results. Such a formula does not capture important factors over which management may or may not have had control. Also, the study allows top management to design and distribute the bonus payments with virtually no oversight by the FERC. It is assumed that they will distribute bonuses to those who most deserve them. I think such an assumption is at best hopeful speculation, if not naive. I'm inclined to agree with the skeptical maxim about executive bonus programs which says: Top management writes bonus programs for top management.

My strongest objection is to the study's recommendation that rewards to managers be funded by ratepayers. Why should managers be given additional compensation for what they are supposed to be doing in the first place--providing adequate service at least cost? Whether called incentives, rewards, or bonuses, they all do the same thing: increase the average level of managers' salaries. I am not suggesting that incentive programs have no value, but that the basic incentive to do a professional job is the base salary paid to employees, whether a utility lineman or company president. The recommended bonus program suggests that the average compensation level now paid top management should be raised and that the structure of compensation has to be changed. The average salaries of these managers, relative to other industries, do not appear to be out of line. Top level managers earn attractive salaries in what has traditionally been a low-risk, stable industry. In contrast, managers of public power systems are paid about 40 percent less that their counterparts in investor-owned utilities and are subject to greater public scrutiny and pressure.

Although the structure of the current compensation system may not be fashioned as well as it could be, the average levels of compensation paid managers should not be increased at ratepayers' expense. If there is a need to restructure management compensation, it could be done by restructuring management compensation at current levels. This would involve lowering current base salaries and using the amount of the reduction for bonus payments, thus keeping the average salary level the same.

Our objection to the particular program recommended by RCG should not be interpreted to mean that APPA is opposed to any form of systematic, quantitative evaluation of the industry's efficiency performance. Quite the contrary, we believe the FERC should implement evaluative measures. Unfortunately, the RCG study will probably be used to discredit systematic, quantitative measures of management performance. Already the trade press reports that the industry is preparing a highly critical statement of the study's recommendations. This is not surprising since the industry has generally opposed having their managers evaluated on the basis of any type of objective criteria. For example, they were highly critical of the FPC's "Performance Profiles" (1973) and of the methodology NARUC proposed in the mid-1970s for measuring the cost performance of the electric utility industry.

I think the best way to encourage utilities to maintain and strive for the lowest possible rates is by continuous and direct analyses of their major cost decisions. Instead of paying millions of dollars in bonuses to managers for work they should already be doing, the dollars could be better spent developing a vigilant, active, and highly sophisticated regulatory staff to investigate the major cost decisions made by these managers. Management awareness that such a staff exists and that commissions will not allow the cost of imprudent decisions to be borne by ratepayers is a more direct and certain means of encouraging efficient management decision-making than through an intricate and uncertain system of bonus payments.

APPA appreciates this opportunity to express its views, and will be interested in reading the FERC staff's recommendations on incentive programs.

Sincerely,

John Kelly

John Kelly
Staff Economist

JK/af

ADDRESS ALL COMMUNICATIONS
TO THE COMMISSION
CALIFORNIA STATE BUILDING
SAN FRANCISCO, CALIFORNIA 94102
TELEPHONE (415) 557-1341

Public Utilities Commission

STATE OF CALIFORNIA

FILE NO.

February 11, 1983

Bernie Tenenbaum
Office of Regulatory Analysis
FERC
825 N. Capitol Street, N.E.
Washington, D.C. 20426

Dear ~~Mr.~~ Bernie Tenebaum:

Thank you for the opportunity to comment on the Draft Report of October, 1982, "Incentive Regulation in the Electric Utility Industry."

Our attached comments are rather critical of the highly theoretical arguments advanced for the rate control incentive program. It is ironic that many of criticisms parallel the consultants' own critique of Total Factor Productivity (Appendix B).

Despite the shortcomings of both methods, we would encourage you to continue the effort. Rather than further theoretical work, it would be very helpful if more actual case analysis was done on comparative unit costs and revenues of some of the major electric utilities. The National Regulatory Research Institute has done work in this area and should be considered in the event you are in a position to contract for an additional effort.

It would be appreciated if you would keep us informed of any reports prepared by your staff or of other efforts being undertaken. President Leonard Grimes of our Commission who is Vice-Chairman of the NARUC Committee on Electricity has also recommended that the committee support further efforts for development of incentive regulation.

Very truly yours,

Barbara

Barbara Barkovich, Director
Policy and Planning Division

Attachment

COMMENTS ON CHAPTER 2 - FOCUS

A strong case is made for focusing on aggregate cost performance in order to (1) minimize cost of service, (2) avoid giving inefficient price signals to a firm which could be created by over-emphasis on one subset of costs, (3) have less detailed involvement in utility management, and (4) impose less administrative burden on the regulatory agency.

The report recognizes, however, that unlike FERC, with a much larger number of regulated firms, a state commission might be able to accommodate the expense and administrative burden of becoming more involved in utility operations. While a focus on aggregate cost performance is very significant and justified, it does not follow that the analysis should stop there.

The report assumes only one homogenous output, kilowatt-hours (Chapter 2.8 and Appendix B.4). However conservation should also be considered an output because of the amount of capital equipment, operating expenses and organizational changes required to achieve a goal of the most efficient usage by all classes of service.

Two recommendations which appear to be desirable are:

a. Encourage long-run cost minimization by awarding incentives on the basis of 3-5 years' performance, although costs may rise for short transitional periods (Chapter 2.12).

b. Assume reliability of service by quantifying outages and consequently adjusting any incentive downward if this lost service resulted from management's actions to reduce costs at the expense or inconvenience of ratepayers (Chapter 2.10).

Length of Performance Measurement (Pages 2.12-2.14)

We concur in the need to average the data over several years to dampen the effect of year-to-year random variations in a utility's operating conditions. This purpose is defeated, however, by the recommended non-uniform weight structure and the recommended dynamic measure of comparing the most recent year with the preceding five year average.

PG&E's authorized rate level over the last five years varied from a low of 3.7¢/kWh in 1979 to a high of 9.1¢/kWh on January 1, 1982. Due to fortunate climatological conditions, the rates authorized on January 1, 1983, were back down to 6.9¢/kWh. The methodology proposed does not appear to deal with this type of actual experience. (PG&E probably wouldn't object to being compared to the static rate level of $0.63/kWh used in the example.)

<u>Evaluation Relative to...Other Utilities</u> (Pages 2.16-2.20)

Comparisons between utilities over time can be affected by major intertemporal changes in business circumstances which cannot be disregarded as suggested in the report (see further development in comments on Appendix D).

Forming groups of firms based on such factors as size, sales and load characteristics and growth, and state environmental and tax burdens is an important step in evaluation relative to other utilities. We do not understand the statement which suggests that variables which are important in explaining differences among firms' performance (p. 2.19) service be discarded. Essentially, one of the principal reasons that an aggregate cost analysis need be accompanied by more detailed comparisons is so that important differences in performance will be understood.

As indicated in the discussion in Chapter 4 (p. 4.21 and 4.22), grouping is perhaps the most controversial aspect of the recommended procedure. Contrary to the report, we believe that firm-specific attributes (such as percent of generating capacity that is coal-fired, p. 4.21) have to be considered. Such a firm-specific attribute is frequently affected by a utility's location and environmental concerns annd requirements.

CHAPTER 3
STRUCTURING THE INCENTIVE MECHANISM

The focus on compensation as an incentive for improved performance is well founded in other industries. The utility examples described in Appendix G are very informative. It is noted that some apply to aggregate performance and one to plant performance.

We are not sure that compensation payments would be less than compensation through earnings (p. 3.3) since a fully effective compensation plan might require much wider participation than the few executives suggested in the report. We do not believe that the possibility of managers arguing for an otherwise low return on equity is a real problem (p. 3.5). We do not agree that a generic rate of return approach is a necessary part of an incentive program.

We do not agree that "the potential assessment of dollar penalties for so-called inferior performance may be impracticable and counter-productive to the goals of the program." or..."the assessment of dollar penalties may cause an incentive program to be politically unsaleable." (p. 3.7). Such mechanisms have been used successfully in states like California.

Since a program should consider both rewards and penalties, it may be necessary to consider both compensation and earnings to overcome the arguments against penalties set forth on pages 3.8 and 3.9.

We concur that sharing incentive compensation awards within the firm (p. 3.13) should be under a program designed by management. In fact, a utility should be encouraged to expand its own programs for various components of operations subject to regulatory review as part of the determination of reasonable cost.

COMMENTS ON CHAPTER 4
RECOMMENDED INCENTIVE REGULATION PROGRAM

We are not convinced that the proposed rate control incentive program (RCIP) promotes cost minimization more strongly than does the traditional regulatory process (p. 4.2). We believe that it could be used with other regulatory initiatives to improve the process and that it should be studied further. It would be necessary, as recommended in the report, for the FERC to work with state regulatory commissions to implement such a program. We are not optimistic, however, that adoption of a generic procedure for determining the rate of return on equity for utilities covered by the RCIP could be agreed to by FERC and the state regulatory commissions (p. 4.3).

We do not believe the steps recommended on p. 4.5 through 4.9 will produce data that can be used in performance measurement for the reasons stated in our comments on Chapter 2. Multi-year averaging is necessary to compare static rate levels but a more detailed procedure appears necessary to develop a dynamic index. Conceptually we agree that the methodology should account for a utility's change in performance as well as the average rate levels. An analysis is necessary of the components parts of the aggregate revenue base in order to evaluate both the static and dynamic performance.

While the management compensation features of the plan would require the voluntary participation of the utility, measurement of performance should apply to all regulated utilities (p. 4.20). Whether good performance is rewarded by more liberal expense allowances or a higher return on equity is secondary to the need for specific findings on the effectiveness of the utilities operations. Additionally, Chapter 4.22 states that the plan should be implemented on a coordinated basis with state regulatory agencies. Without such cooperation, an incentive to shift constrained cost across jurisdictional lines would be present even if not consciously acted upon by management.

COMMENTS ON CHAPTER 5
ADDITIONAL INCENTIVE PROGRAM POSSIBILITIES

Construction Cost Control Incentives

FERC's consideration of a regulatory incentive system for ANGTS was necessitated by federal legislation which dealt specifically with that project. The New York Public Service Commission's special consideration of NMP-2 arose out of proposals to abandon that project.

We recommend that special circumstances such as these and other potential plant abandonments not be used as precedents for developing a procedure to encourage private firms to undertake equity sponsorings of large-scale projects through cost-of-service guarantees. Utilities are responsible for the prudent management of construction projects. Rate incentive programs alone will not assure construction cost minimization, although they should be investigated further.

Automatic Rate Adjustment Mechanism

The recommended procedure merits further and more detailed examination. Even if it is not adopted as a rate adjustment mechanism, refined data would be very useful in comparing disaggregated unit costs for comparable utilities over a multi-year study period. It is possible that the Rate Control Incentive Program could be extended to include a disaggregated basis and combined with development of appropriate indexes using some of the procedures included in Chapter 5.

COMMENTS ON APPENDIX A
REVIEW OF SELECTED STATE-LEVEL PROGRAMS

We do not agree that the Florida, Michigan and Utah programs "tends to assume automatically that overall corporate efficiency is maximized if one or more sub-corporate level performance standards are met." (p. A.3). In fact a number of states are endeavoring to extend incentive regulation to as many sub-corporate levels possible. As we have commented in previous chapters, these efforts should include participation by other states and FERC. We understand and agree that administratively sub-corporate analysis would be infeasible for FERC (p. A-4).

COMMENTS ON APPENDIX B
TFP ANALYSIS

Although the report explicitly favors an aggregate cost index as opposed to a total factor productivity (TFP) index (Appendices B and D), and cites FERC decision in Case No. 1419 (Appendix B. 17), TFP may still prove useful as an overall indicator of the utility's performance and management of total financial, organization and labor resources.

COMMENTS ON APPENDIX D
[illegible] INDEXES

Both the aggregate unit cost index based on average revenue and on average revenue minus returns to capital are greatly influenced by operating and maintenance expenses. The rankings would be particularly influenced by fuel and purchased power expenses if the twenty-five utilities include some that are heavily dependent on low sulfur fossil fuels.

It is not surprising that there was a high degree of correspondence between the performance ranks for the average revenue and average cost indexes since one would anticipate a fairly uniform ratio of average revenue to the average cost basis utilized. It would be more significant to compare the average revenue indexes to an aggregate unit cost index based on gross revenues minus fuel and purchased power costs.

Several changes in the revenue index rank order for the periods 1969-72 as compared to 1974-75 may be significant in this connection:

Utility 3 - From Index Rank 3-4 to 23-25

Utility 11 - From Index Rank 1-4 to 9-14

Utility 15 - From Index Rank 4-9 to 22-23

With major changes having occurred in utility costs between the 1969-72 period and the 1974-75, some modification in the methodology would seem warranted to take this factor into account.

It is not surprising that there is no correspondence between the aggregate cost and TFP indexes. That does not shed any light on the superiority of one or the other.

COMMENTS ON APPENDIX F

ANALYZING REDUCTIONS IN UTILITY OPERATING EXPENSES

The sensitivity analysis properly identifies the inadequacy of trying to develop a single factor to apply to such a diverse group of utilities as an incentive to improved performance. The particularly wide range in cost category #5 (principally labor and equipment costs) with a percentage as high as 12.74% reduction for a 1% change in return on equity is significant in identifying the characteristic of one type of utility. If as diverse a group of utilities is included in Comparing Aggregate Cost Indexes (Appendix D), the rankings would be subject to serious limitations as to their usefulness.

The example on page F-12 of permitting return on equity to increase 25 basis poits for each 100 basis points reduction in real cost would, of course, be viewed from entirely a different perspective if applied to a utility where 1 percent cost reduction would be equivalent to a 1 percent increase in return on equity.

CRITIQUE AND APPRAISAL

CP&L joined with several other utilities in obtaining the services of National Economic Research Associates, Inc. (NERA) to prepare a comprehensive critique of the RCG draft report. That critique is being filed separately. Although we do not necessarily agree with every statement and shade of opinion in the critique, we concur in its major findings, and therefore CP&L joins in sponsoring the NERA comments. We ask close attention to the very realistic practical concerns expressed by NERA.

Before moving to a set of ideas for further action to find the solutions, may we emphasize some of the aspects of concern about the RCG suggestions.

1. A basic premise of the RCG report - and of a number of proposals for modifying the present regulatory process - is the notion that regulatory lag no longer provides an effective incentive for operating efficiency. This premise is not well-founded. Whatever benefit (if there is any) that accrues from filing rate cases more frequently than in former times is more than offset by the rapidity and severity of increases in costs. The inability to earn allowed rates of return has been documented repeatedly. Regulatory lag as an incentive to efficient operations is still very much present and very effective.

2. Comparing performances by end results measurement requires neutralizing the effect of factors beyond the control of management. The NERA presentation has detailed many of the difficulties in this necessary aspect. May we here simply emphasize the seemingly hopeless task of identifying and quantifying all of these factors when (1) small differences can lead to large variations in end-result measurement, (2) comparisons are to be made among a number of companies, not only at a given time but also over periods of time, and (3) the current management is neither to receive incentive compensation, nor to be denied such compensation, because of the wisdom or lack of wisdom (both in retrospect) of the decisions of prior managers.

3. The concern expressed in the NERA comments about the above effect of the proposed program on the exchange of knowledge among utilities is alarming to this operating company. In effect, the program would put managers of utilities in competition, rather than in cooperation, for increased "know-how." No one utility can pursue on its own every

aspect of managerial and technical knowledge. Industry members have relied heavily on each other for the exchange of ideas for improved management and operation. The importance of this exchange, and the potential for its destruction by a plan which pits one management in competition with another, cannot be overemphasized.

4. Of the two alternative proposals presented by RCG, the construction cost incentive proposal is the less satisfactory. The overwhelming problems stated in the NERA analytical approach are confirmed by actual experience.

FUTURE COURSE OF ACTION

1. Compensation Incentive.

Despite our belief that the major proposal of the RCG report and also its first alternative proposal do not offer much promise of feasibility, CP&L does believe that the Commission should encourage efforts to develop incentives to efficiency within the traditional regulatory approach and also as a possible modification of the traditional approach.

As a first step, resulting directly from the RCG report, the Staff and the Commission might formally indorse the concept of regulatory attitudes toward (and thus support of) reward programs that, according to the economic way of thinking, will encourage the utility manager to better his performance in terms of economic efficiency.

Such an indorsement could be accompanied by basic standards generalized as to objectives, with perhaps basic outlines of the nature of plans that may be valuable when applied to particular utilities.

One such standard might be that methods must be simple to understand and acceptable to the public. Thus, what kinds of plans would lead to public understanding and acceptance should be a subject for research in any agenda on incentive ratemaking.

In our tentative thinking in response to the RCG report, we have concluded that, for some of the same reasons that make the RCG proposal not workable, such a plan directed at managers probably should be custom-built for the individual utility. Probably only this approach enables suitably identifying and promoting managerial efficiency in those corporate activities that current management of the particular company can directly impact substantially.

For some companies incentive plans may be inappropriate, and thus another aspect of the indorsement should be that plans be voluntary on the part of the utility. Clearly any program of compensation of utility managers should not exceed limits fixed by the board of directors of the utility.

Thus, we suggest that the Commission conclude not to pursue the compensation incentive ideas explored by RCG but instead, as one course of action, indorse the concept of voluntary programs developed by individual companies to meet their specific circumstances.

2. Indexation Incentive.

In Chapter 5 of its draft report RCG suggests a second incentive alternative designed to reduce the frequency of rate cases and provide reasonably long periods for the operation of incentives to better manage production costs. The mechanism is an automatic rate adjustment program based on inflation in the price of production inputs. As stated in the report at p. 5.23, the basis for changes in initial rates would be determined by economic conditions and forces outside the utility's control.

While some generalized aspects of such a program are described in the draft report, as the NERA analysis points out the description "is not spelled out in enough detail to be evaluated fairly." However, we emphasize the NERA belief that such an approach may offer promise. While the questions it raises are many, their solution seems less awesome a problem than the solution to the many concerns raised about the major proposal and the first alternative in the RCG report.

Certainly the goal is most desirable: to achieve rates which are quite close to those which a continuing rate case should produce under sound regulatory principles and efficient operation, but without the crushing burden of repetitive cases. An indexation that materially advances the opportunity to actually attain the financial results anticipated in a rate order may be a different type of incentive than the basic RCG proposal contemplates, but it would be one that motivates the manager to the highest efficiency.

CP&L is very encouraged by the efforts to find one or more mechanisms that will provide additional incentives to improve productivity and enable better financial results. We encourage the Staff and the Commission to take a lead in the public forum to create acceptance of the concepts and their implementation. As with any difficult research undertaking, the development must be deliberate and pragmatic, for serious adverse consequences could result from an ill-conceived plan. May we suggest a call for an agenda for research - one we cannot develop in this short time period for commenting - prior to the institution of a formal rulemaking proceeding.

For your convenience I enclose an extra copy of these comments.

Yours truly,

Samuel Behrends, Jr.

Samuel Behrends, Jr.

SBjr:mhm

CHARLES RIVER ASSOCIATES INCORPORATED

JOHN HANCOCK TOWER
200 CLARENDON STREET
BOSTON, MASSACHUSETTS 02116
(617) 266-0500 TWX: 710-321-1926

February 24, 1983

Dr. Bernard Tenenbaum
Acting Chief, Economic Analysis Branch
Office of Regulatory Analysis
Federal Energy Regulatory Commission
Washington, D.C. 20426

Dear Bernie:

Thank you very much for your letter of December 7, 1982 and the invitation to comment on a draft of a report by the Resource Consulting Group Incorporated (RCG) entitled "Incentive Regulation In The Electric Utility Industry" (DE-AC39-82RC-11849, RCG No.: RA-82-0143). The subject is an important one, and the Commission is to be commended for sponsoring this analysis. I appreciate this opportunity to record my views.

I have read the report in its entirety several times, and will address the report as a whole, but you suggested that I might limit my comments to a few topics. As the comments attached indicate, I find myself unpersuaded by RCG's conclusions. Nonetheless, it is a thoughtful and professional work. Both the authors and the FERC staff can be proud of this report. It is a contribution to the literature on an important and complex problem.

Again, thank you for this opportunity. If further comments would be of assistance to you in regard to this matter or any other matters, please let me know.

Sincerely yours,

CHARLES RIVER ASSOCIATES

George

George R. Hall
Vice President

GRH:jrp

COMMENTS OF GEORGE R. HALL, VICE PRESIDENT
CHARLES RIVER ASSOCIATES, INC.
200 CLARENDON STREET
BOSTON, MASSACHUSETTS 02116
ON DRAFT REPORT BY
RESOURCE CONSULTING GROUP
TO FEDERAL ENERGY REGULATORY COMMISSION
ON "INCENTIVE REGULATION IN THE ELECTRIC UTILITY INDUSTRY"*

INTRODUCTION**

RCG undertook a two-fold task with this report. First, RCG had to move from general considerations about utility incentives and select a specific incentive approach to electric utility regulation and design a specific, implementable plan. Second, RCG had to evaluate this plan and recommend to the FERC whether or not it should move forward to try to implement it.

To anticipate my conclusions, upon reflecting on the results of RCG's analysis, I believe that the approach that RCG selected is not the approach 2 would recommend. I find myself persuaded by RCG's analysis that the approach that RCG refers to as the "Automatic Rate Adjustment Mechanism" (ARAM) has more promise than the approach RCG recommends. My recommendation to the FERC would be not to move forward with the approach with RCG's preferred approach, but rather attempt to develop an approach along the line of the ARAM alternative.

I hasten to add that the fact that I find RCG's analysis and recommendations unpersuasive should not be taken as implying a lack of appreciation for the report. It is a well-done, professional and helpful analysis. It advances the discussion of this complex and important topic. Both RCG and the FERC are to be commended for making it available to the various communities concerned with the utility industry.

The report argues that electric utilities have fewer efficiency incentives than firms in nonregulated competitive markets because: (1) they are limited to "reasonable" rates of return; (2) less efficient firms get price increases from regulators that could not be obtained in competitive markets; and (3) the short run inelastic demand for electricity shields inefficient firms from loss of markets.

---

*Draft Report, DE-AC 39-82RC-11849, RCG No.: RA 82-0143, dated October 15, 1982.

**I express thanks to my colleague, A. Lawrence Kolbe, for helpful comments and suggestions. I have also had the benefit of discussing this report with various members of the Federal Energy Bar and the Electric Utility Industry. I am greatful to them, but the views expressed here are solely my own and should not be attributed to any other individual, group or organization.

The report further argues that the traditional incentive for efficiency has been regulatory lag and regulatory cost scrutiny is less effective now than it has been in the past because of the need to have more frequent rate cases due to inflation and the increasing use of automatic cost adjustment clauses. RCG concludes that there is a pressing need to provide additional incentives for utilities to attempt to improve efficiency, which is defined by RCG as minimizing total cost of service.

On these predicates, RCG discusses seven topics:

- The incentive target or the focus of the incentive program;
- How to measure performance;
- How to evaluate performance;
- The incentive mechanism, i.e., should rewards and penalties effect the return, the rate level, or management compensation?;
- The structure of the incentives, i.e., should there be rewards or penalties and how should rewards and penalties be shared between the firm and its customers?;
- How to allow for factors beyond the firm's control;
- How to implement a program.

I shall comment briefly on each topic.

THE INCENTIVE TARGET

The report considers various possible focuses for the incentives that might be provided electric utilities to reduce costs. RCG discusses targeting on the aggregate performance of the utility (i.e., rates), focusing on a subset of activity (such as generation), focusing on markets (retail or wholesale), or focusing on some subset of inputs or operations. RCG selects the entire company performance, that is, rates, as best measuring the benefits to consumers. I agree but this choice means that one must move in to the murky area of economic measurement rather than relying upon more precise engineering measures. Nonetheless, I believe that for incentives to deal with what they should deal with, minimizing utility rates is the correct target.

PERFORMANCE MEASURES

The report considers various possible performance measures such as total factor productivity, disaggregate unit cost measures, and physical productivity measures. The report selects an aggregate cost measure as the most consistent with the focus chosen for the incentive program. I concur. The discussion of the drawbacks to the use of the total factor productivity approach is a particularly good analysis.

PERFORMANCE EVALUATION

The report considers four possible performance standards against which performance might be measured. They are: (1) relative to a firm's own past performance; (2) relative to the performance of other firms; (3) relative to the past performance of other utilities; and (4) an independent standard. RCG selects an index combining the first two possibilities. That is, the suggestion is that customer rate would be evaluated both relative to the rates of other firms and to the change in the firm's own rates over time.

The RCG solution finesses the problem of choosing between a cross-firm measure and a measure based on the past performance of the specific firm being regulated. Certainly it is difficult to choose between the two measures; each has advantages, so an index that combines them has considerable appeal. Nonetheless, the RCG weighting mechanism is arbitrary. I believe that probably any weighting system would also be arbitrary. The difficulty is that I doubt that an arbitrary weighting system for a matter that has as significant financial consequences as an incentive system of the sort proposed here is compatible with the procedural due process requirements inherent in rate setting by public utilities commissions.

Put differently, I suspect that any weighting system has to be somewhat arbitrary. What worries me is that the problems of defending the weighting system before challenges within the commission and within the courts are likely to be considerable. The result could well be so much time and effort spent arguing about weighting that any benefits to the consumer would be counterbalanced by the increased regulatory costs.

It should also be noted that the performance evaluation technique selected by RCG makes the problem of allowing for factors beyond the control of management a critical issue. I shall address this topic later in more detail. But because it has been the shoal upon which most past attempts to develop an incentive program have foundered. It is worth emphasizing this problem at this point.

The most serious problem I see with the performance evaluation proposed is that it requires classification of firms into groups. This is an extremely challenging task. The report suggests the groups used for the generic rate of return technique that was proposed by the FERC be used for the incentive scheme. However, it is my understanding that the generic rate of return proposal has been subject to considerable change, in part because of the difficulty of determining how to define groups satisfactorily.

It is also suggested that in addition to statistical techniques, expert panels could classify utilities in the sense of similar firms. The expert panel technique is a very useful one for research purposes. I am dubious, however, that classification by expert panel would stand up under requirements of due process for any matter with as significant financial consequences as an incentive rate of return.

With regard to the weighting technique, I would note that the numerical example used in the report contains an error. Nonetheless, the formula accomplishes what the report says it will accomplish. On the other hand, this is an ad hoc formula; no comparison is offered by RCG as to how this formula compares to the results of other ad hoc formulas with respect to accomplishing what the authors wish the formula to accomplish.

THE INCENTIVE MECHANISM

The report considers three possibilities with respect to embodying rewards and possibly penalties in some utility cost element. The possibilities RCG considers are to reflect the incentive in: (1) the allowed rate of return; (2) the actual rate of return; (3) or management compensation. RCG strongly advocates that the incentive should be flowed through to management compensation. Indeed, this feature is the most significant aspect of the RCG proposal. The report argues at length that management activity is the key to cost improvement and, therefore, for an incentive system to work, regulatory commissions must be sure that rewards are used to motivate management through higher incomes.

This part of the proposal troubles me greatly. Basically it would require regulatory commissions to enter into a realm of public utility control which hithertofore has largely been left to the responsibility of the utility stockholders and the utility board of directors. I think there is good reason for not introducing public utility regulation into this sphere.

Basically, if the RCG's scheme were implemented, all regulatory commissions would have to exercise close and detailed scrutiny over management compensation plans. The report implies that requirements could be set up to insure that any management incentives were additional to basic compensation. It is also argued that this could be done with an acceptable level of reporting and enforcement activity. I am very dubious.

As the history of the various wage freezes that have been imposed by the Federal Government on the economy as a whole or, more often, on the Federal Civil Service, will establish, distinguishing between base compensation and incentive compensation would be an extremely difficult job. I believe that as a practical matter, directing the incentive to management compensation, would require regulatory commissions to develop detailed management compensation plans for each jurisdictional form. I am dubious that public utility commissions have the time, resources or expertise to allow them to do such a job effectively.

Moreover, even if it could be done, I am not sure that it should be done. Philosophically, it seems to me that a strong case can be made that the social contract inherent in public utility regulation should be structured so that general requirements are layed down by public utility commissions upon the stockholders of the regulated firms and their delegates, the board of directors. The stockholders and the board of directors should then decide how the objective will be achieved. From a philosophical point of view, I would argue that any rewards from an incentive scheme should go to the firm as an undesignated sum. The firm should decide how the rewards should be parcelled out. I would prefer that the reward or penalties be reflected in the rates of return (either actual or allowed) and that the regulated utility's board of directors have the authority to decide to what extent it would pass the research through to management. If in fact managerial action is the key to efficiency improvements it would seem logically to be in the interest of the board of directors to flow most of the incentive through to management to __________ the improvements that result in records.

INCENTIVE STRUCTURES

The report considers at some length the question of whether there should be rewards only, penalties only, or both. The conclusion is that a rewards only system is the preferred choice.

As an intellectual matter, I find the report persuasive on this point. However, knowledgeable people with whom I have discussed this matter are of the opinion that a one-sided reward system would be politically unacceptable with state regulatory commissions. They tell me that the perception of such a scheme would be that it was a "heads I win, tails you lose" proposition offered to utilities. I think this comment has a great deal of force. It presents a sharp dilemma. For the reasons the RCG report makes clear, a system that has either only penalties or has both rewards and penalties presents a great deal of economic and regulatory difficulty. On the other hand, any incentive system must be not only equitable but perceived as equitable and that requirement probably implies penalties as well as rewards, considering the current climate in which state regulation takes place.

The question of how the penalties and rewards should be structured brings up another matter that I think is of absolutely critical importance. This is, how can one guarantee in advance to the potential recipients of the rewards that the rewards promised them will actually be available when earned. That is, imagine a program of the sort conceived by RCG being implemented and assume that after 5 years, due to significant increases in performance, a utility has a substantial reward coming. Assume that in the meantime the composition of the cognizant public utility commission has turned over. Will the new commissioners honor the prior committment? More important, will management today believe that in five years a new commission will honor the incentive commitment. I am a great believer in the importance of regulatory reliance but it is difficult for one commission to bend its successors.

Looked at from the other prospective, a subsequent commission may find itself in the position of having to impose a substantial increase in rates upon its customers for a program that it did not design. Keep in mind, that under the RCG proposal we are talking about superficial sums of money.

I have had expressed to me the view that the regulatory dynamics involved would, in practice, result as a rewards only system or a rewards-and-penalty system deteriorating into a penalty-only system. A penalties-only system would likely be unable to achieve the benefits sought by the RCG proposal and it could have very serious counter-productive effects.

The report discussed various possible time patterns for sharing between firms and customers and various possible ways that the incentive benefits might be shared. A number of complex issues are raised but are not resolved. Should the FERC decide to move forward with this proposal, considerable effort should be devoted to resolving the issues raised in this section.

ALLOWING FOR FACTORS BEYOND THE UTILITY'S CONTROL

This is the most complex issue. I believe there would be general agreement with adjusting for factors such as total generating capacity, average load factor, historical and forecast load factor, percent of sales to residential and commercial customers, environmental requirements, and state and local taxes. The controversial question is whether allowances should be made for the effects of past decisions of management.

I am sure that this question will arouse fierce controvery amongst those who comment on this report. The dilemma is that if the incentive system adjusts for the effects of past decisions, any utility will be perceived as having very little opportunity for efficiency improvement. The nature of the utility investment is that it is exceedingly long-lived. Consequently, any existing management has to deal primarily with the consequences of its predecessor's actions.

On the other hand, if allowance is not made for the past decisions of management, questions of equity arise. Also, questions of whether the incentive reward really reflects the skill and ability and effort of the current management or the foresight or luck of prior managements will present itself. My preference is, as RCG recommends, not to adjust for the effects of past decisions of management. However, this is not an obvious call and I am sure it is going to generate intense heat. I do not believe that the report will end the debate.

RCG appears to overlook the problems of asset vintages and "rate shocks" from large, new plants. The report discusses capital costs and cites them as a major problem for the automatic rate adjustment approach. However, with regard to the proposal that RCG recommends, the asset vintage and rate stock problem is not addressed even though it applies with equal force.

A number of implementation problems have been discussed in connection with the other topics. I would particularly highlight the problems of the whether rewards should be flow-through to management and the enforcement and reporting requirements. I am not nearly as sanguine as RCG that an acceptable management compensation scheme can be achieved with an acceptable level of enforcement and reporting requirements by the cognizant regulatory commissions.

I would also underscore the point made by RCG that for this incentive system to work it must cover both wholesale and retail sales. This requires involvement of the state utility commissions in some joint plan. This is not going to be an easy task to accomplish.

Moreover, to repeat, one must be very cognizant of the problems of insuring that the rewards will be payed when earned, and that the system will not become merely one-sided penalty of the program. One must also ensure that the rewards be substantial if they are to be motivators. In working with the ______ state entities that would have to cooperate in this plan it will be difficult to maintain these parameters.

ALTERNATIVES

The report discusses the use of incentive rate of return schemes for construction projects. The procedure adopted for the Nine Mile Point Two nuclear plant and for the Alaska Natural Gas Transportation System NAGTS are cited. The discussion, however, does not feature the caviats and requirements for such a system as these are set out in the orders establishing both incentive schemes. Since the predicates for effective incentive scheme are well discussed in both those orders, I will merely invite attention to them and leave the subject. The report seems to mistakenly assume that the FERC has certification authority for electric utility plants. This mistake should be corrected in the final report.

An automatic rate adjustment mechanism (ARAN), is proposed as a possible alternative. I note that a similar scheme has also been proposed recently by Professor Baumol. RCG rejects this proposal on the basis that there is no acceptable method to index capital costs between rate cases. RCG also argues that there is a potential to "game" the system, that is hold off cost saving investments until just after a rate case. Both of those criticisms, although well-founded, apply with equal force to the proposal recommended by RCG. The problems are generic rather than associated with any particular approach.

RCG also argues that the ARAM system is inferior to the system it proposes because ARAM provides incentives for stockholders, not management. As discussed earlier, I am not sure this is a drawback. In fact, it is probably an advantage.

Finally, RCG believes that an ARAM system will increase a firm's cost of capital. This may or may not be true. It does not seem to me to be a self-evident point.

I believe that the implementation problems for the system as proposed by RCG are so great that the greater compatability of an ARAM approach with conventional public utility regulatory procedures makes it the preferred approach. I believe that one could select indices for a large number of the elements in the typical utility's cost of service and thereby permit much longer periods between rate cases as well as more regulatory attention to the elements that are not indexed when rate cases occur. After considerable and sympathetic consideration of the RCG proposal, I have come to the conclusion that the ARAM approach is superior.

There is also another possibility that might well be considered by the FERC. This would be to require each individual utility to come in with its own incentive proposals. Another possibility would be to require utilities to propose individual management compensation incentive programs. There is much in what RCG says about the importance of management incentives. It is also noteworthy that utilities seem to lag the other types of firms in structuring explicit performance incentives in their compensation plans. Perhaps it would be possible to get at the incentive questions indirectly by persuading utilities to set up more incentive programs for their management. If RCG is correct, it would seem that one could skip the problem of trying to develop rate incentives and move directly to require utilities to have management incentive compensation plans. As noted, I am dubious about utility commissions establishing uniform generic programs. I would prefer a case-by-case or utility-by-utility procedure.

CONCLUSION

In short, I believe that the conceptual regulatory and implementational problems inherent in the RCG proposal argue against the FERC moving forward with it. I believe these problems are inherent and not remediable. In general, I prefer the ARAM approach. It lacks some of the theoretical elegance of the rcg proposal, but it has the virtue of being more easily implemented and administered and more compatible with basic public utility regulation policies and procedures.

EDISON ELECTRIC INSTITUTE The association of electric companies

1111 19th Street, N.W.
Washington, D.C. 20036
Tel. (202) 828-7400

March 10, 1983

Dr. Bernard Tenenbaum
Acting Chief
Economic Analysis Branch
Office of Regulatory Policy Analysis
Federal Energy Regulatory Commission
825 N. Capitol Street
Washington, D.C. 20426

Dear Bernie:

Enclosed are the original and (2) two copies of Edison Electric Institute's (EEI's) comments on "Incentive Regulation in the Electric Utility Industry." These comments were prepared on behalf of EEI member companies. Because of the varying circumstances of EEI member companies, a number of companies will be submitting comments on their own behalf which address selected aspects of the study from the perspective of their individual needs and circumstances.

A major theme of EEI's comments is that incentive programs should not be regulated by FERC or state commissions. To the extent that incentives to insure the promotion of innovation and cost reduction are possible, EEI member companies are better able to fashion incentive programs that are useful in their individual circumstances to stimulate such improvements.

The subject study certainly reflects a great deal of thought on a complex topic. There is sufficient merit to warrant further consideration of the issues raised in EEI's comments and those of its member companies. EEI would be pleased to work with FERC in further study of these issues. If you wish I can arrange for you, as well as other FERC staff and the contractor, to meet with EEI member companies about these comments.

If you have any questions about these comments, or if I can be helpful in some other way, please do not hesitate to contact me. Thank you for giving EEI the opportunity to comment on the study. I look forward to hearing from you in the near future.

Sincerely,

Dave

David K. Owens
Director

DKO:mc
Enclosure
cc: Douglas C. Bauer
EEI, Senior Vice President

BEFORE THE STAFF OF THE

FEDERAL ENERGY REGULATORY COMMISSION

Incentive Regulation) in the Electric) Utility Industry)	Informal Request for Comments dated December 7, 1982

Comments of the
Edison Electric Institute

Douglas C. Bauer
Senior Vice President
Economics and Finance Group
Edison Electric Institute
1111 19th Street, N.W.
Washington, D.C. 20036

Washington, D.C.
March 9, 1983

Table of Contents

Comments of the Edison Electric Institute on Draft Report
of Resources Consulting Group, Inc.:
"Incentive Regulation in the Electric Utility Industry"

Edison Electric Institute (EEI) hereby submits its comments in response to the request of the Staff of the Federal Energy Regulatory Commission on the Draft Report entitled, "Incentive Regulation in the Electric Utility Industry," which was prepared by Resources Consulting Group (RCG) for the Federal Energy Regulatory Commission (FERC) under date of October 15, 1982.

I. <u>Introduction</u>

EEI is the association of the nation's investor-owned electric utilities, whose member companies provide electric service to 99 percent of all customers of the investor-owned portion of the industry and 77 percent of all users of electricity in the United States.

EEI appreciates the opportunity to submit comments to FERC on this document as it discusses a very important issue affecting our member companies. We hope that these comments will be found useful and that FERC will continue to seek EEI's input on the development of issues relating to regulation by FERC.

A substantial number of EEI's member companies are subject to rate regulation by the Federal Energy Regulatory Commission (FERC) and would be directly affected by any action taken by FERC on incentive regulation. Because of the varying circumstances of EEI member companies and the potential effects of any formal action by the FERC on the subject of incentive regulation, a number of companies will be submitting comments on their own behalf which address selected aspects of the draft study from the perspective of their individual needs and circumstances.

II. Overview

In an unregulated and competitive industry, efficient corporate performance is typically rewarded by increased profits and larger market shares. In a regulated industry, such as the electric utility industry, however, there are defined service territories and rates-of-return which are set by the regulatory process. Frequently, the rates-of-return authorized in rate cases do not reflect the current costs-of-capital to investor-owned utilities. Moreover, utilities often do not earn the rates-of-return authorized in rate cases.

While ideally, utility regulation seeks to recognize and balance the interests of regulators, ratepayers and utility investors, regulators have traditionally felt less confident of their ability to assure innovation and optimal efficiency. They have, therefore, sought by various means over many years to develop techniques and create programs that would serve as effective substitutes for market competition in stimulating efficiency in the supply of electric service. Utility managers have been equally concerned with providing reliable, economic and efficient service to their customers and have consistently taken steps aimed at reducing costs and improving overall performance. Commissioning of the subject study, "Incentive Regulation in the Electric Utility Industry," represents an effort by the FERC to explore additional ways of promoting efficiency within the context of regulation.

While each of the proposals contained in the subject study has both conceptual problems and practical limitations, each has sufficient merit to warrant further consideration. EEI does not feel, however, that incentive regulation programs should be designed or administered by the FERC or state commissions. Any programs adopted must be initiated and administered by the individual companies. To the extent that incentives to insure the promotion of innovation and cost reduction are possible, the individual companies are better able to fashion incentive programs that are useful in their individual circumstances to stimulate such improvements. The approaches recommended by the authors would lack the necessary flexibility to account for the variety of circumstances faced by individual utilities.

If FERC perceives itself as having a role in encouraging incentive programs, it could adopt a general policy providing support for incentive programs which can be individually tailored by the utility. However, the initiation of such guidelines will require cooperation between the FERC and the State commissions. It would create difficulties if the FERC and State commissions were to proceed independently of one another in their acceptance of incentive regulation programs administered by the companies. Any incentive mechanism, if limited, for example, to wholesale business only, would be ineffective in creating adequate incentives for most utilities.

If the preferred program--the Rate Control Incentive Program (RCIP)--were implemented, it would represent a basic change in philosophy of regulation at FERC. Regulatory Commissions are now charged with treating investors in these utilities with fairness and protecting the interests of ratepayers. Shareholders now elect Boards of Directors responsible for the selection and motivation of management and charge that management with proper representation of the interests of the shareholders.

If the RCIP were adopted, regulators would be substituted for the Boards of Directors in a basic management function -- the exercise of control over management compensation. Furthermore, the proposal directs the regulators to consider only customers' interests when determining management compensation. The shareholders' interests will no longer be properly represented.

The objective of the FERC in sponsoring this study is, according to the authors of the report, "to encourage improved production performance in the electric utility industry."*

---

*Resources Consulting Group, Inc., "Incentive Regulation in the Electric Utility Industry," prepared for the Federal Energy Regulatory Commission, October 15, 1982, p. iii.

According to the FERC, improved performance would be expected to meet the overall goal of electric utility regulation: ensuring the provision of electric service to ratepayers at the lowest possible price, while providing an acceptable quality of service level and a fair return on investment for the utility.

The various policies, regulations and practices that constitute the process of price regulation in any specific jurisdiction may, depending upon the manner in which they are structured, tend to stymie utilities in their efforts to achieve maximum efficiency in production performance. Therefore, a practical first step for the FERC, in its effort to develop programs that would strengthen innovation and cost reduction, would be an examination of its existing policies, regulations and practices to identify and revise those that do not promote efficient operation. Certainly, EEI and its member companies will be prepared to cooperate to the fullest extent in any reconsideration of such policies, as well as the further study of incentive programs such as those addressed in the subject report.

Rather than examining existing FERC or State commission policies and procedures, however, the subject study deals with incentives on a more general level. It examines possible programs for strengthening incentives to improve performance through additional techniques superimposed on the existing regulatory process. The study raises some important issues worthy of the careful attention of the regulatory community, the industry and the consuming public.

While there are many possible types of incentive programs that may be considered, each of which may have a number of variations, there are other important features in addition to those discussed above, that should be incorporated in any incentive program. These include the following:

1) The interests of all of the stakeholders in the process must be recognized and balanced, i.e., the ratepayers, the regulators, management and investors. For example, RCG simply fails to take full account of the interests of investors who certainly must be treated equitably in any workable system.

2) Since regulated utilities have a legal obligation to serve, any incentive program should include certain provisions that assure that the quality of service (including adequacy and reliability of service) will not be adversely affected. While possibly the most difficult to implement, this requirement is an absolute prerequisite to acceptability.

3) The treatment of any costs of implementation should be established prior to the start of the program. So long as the costs of administration or the wage and salary costs involved in an incentive program are reasonable, there should be an opportunity to have these costs treated as part of the cost of rendering public utility service.

4) The incentive program must be relatively simple. Excessive complexity may not only dilute the ability of the

program to affect incentives; it would also risk the creation of a perception on the part of the public that the program is subject to manipulation.

Neither the preferred program nor the two alternative programs presented by the authors for consideration by FERC conforms with all of these criteria. In addition, there are a number of specific problems with each of the programs. Each, however, has some components that appear to warrant more detailed examination.

Section III, below, discusses the positive features and the limitations of the proposed Rate Control Incentive Program along with some suggestions for improvement. While this program has a number of weaknesses, particularly with regard to grouping and comparison of companies and the specification of awards by FERC, the concept of a management compensation program may be adaptable to the needs and circumstances of individual utilities if fashioned and administered by the Board of Directors.

Section IV discusses two alternative programs proposed by the authors: a Construction Cost Control Program (CCIP) and an Automatic Rate Adjustment Mechanism (ARAM). While the CCIP may accomplish its objectives in individual circumstances, its assumption that utilities can accurately estimate the costs of large construction projects that will not be completed for 7-10 years is dubious. Additionally, use of a variable rate-of-return as an incentive device may not be equally effective in lowering costs of all participating utilities. While the ARAM alternative has a number of problems and will require further study, it's forward-looking approach is a positive and appealing feature which is not incorporated into the preferred plan or the CCIP.

Section V contains concluding comments.

III. Critique of the Recommended Rate Control Incentive Program

A. Summary of Proposed Program

The authors propose a voluntary program in which incentives for efficient performance are strengthened through a system of management compensation incentive awards. A participating utility would be grouped with other "comparable utilities" for purposes of evaluating its relative performance. Such grouping is to be based on selected characteristics that are known to affect unit costs, but which are outside the control of utility management.

Average revenue per kilowatt-hour of sales (R/kWh) would be computed for the current performance period and for a series of past years for each utility in the comparison group. These data would serve as the basis for development of a rate performance index (RPI) for each firm in the group. The RPI would be a composite of a static index value (based on a comparison of R/kWh of the subject utility for the current performance period with the average for the group) and a dynamic index value (based on a comparison of the change in R/kWh of the subject utility over a past period with the average change for the group). Formulated in this way, the RPI would be used to indicate the relative performance of the individual members of a group of "comparable companies."

The incentive mechanism proposed by the authors is the payment of incentive awards, funded by ratepayers, to the key managers of utilities whose index of performance (RPI) exceeds the average of its comparison group. The size of the awards would depend on the magnitude of the firm's RPI. The authors recommend that no dollar penalties be levied, but that negative RPI values be cumulated over a limited period in order to encourage continuous performance improvements.

B. Positive Features

The proposed Rate Control Incentive Program contains positive features. These include the following:

1) <u>The program takes account of both static and dynamic performance</u>. Static indices measure the absolute difference in R/kWh and, therefore, reward past management decisions. Dynamic indices measure improvement from one year to the next in relation to comparable utilities, and therefore, provide a more direct measure of the performance of the current management. Management decisions should reflect incentives to improve both the immediate and long-run measures of performance so that it is important that the program provide rewards measured by both static and dynamic indices.

2) Use of a cost measure that will minimize distortion of allocative decisions. Any measure that uses only a select group of costs as the performance criterion risks the creation of incentives that may lead to concentration of cost minimization schemes in a few areas, leaving other areas untouched. It may, however, be possible to offset or at least minimize such difficulties by judicious selection of costs to be included in the performance criterion.

C. Problems and Limitations

While the plan proposed by the authors has positive features, it also contains a number of problems that require further consideration. Among the more important of these are the following:

1) The program outlined in the report does not reflect quality of service differences. Quality of service is obviously a characteristic that is very difficult to measure. It has a number of dimensions including adequacy and reliability, as well as security of service. It may also include the extent to which a utility maintains a capability for prompt service restoration following emergencies, as well as more intangible customer relation features of its service. The costs of maintaining service of acceptable quality may vary widely across utilities depending on geography, demographic characteristics and other conditions. These difficulties do not, however, justify ignoring quality of service in the RCIP. To do so runs the risk of creating incentives to sacrifice service

quality as a means of improving "comparative performance" as measured by non-quality related statistical measures.

2) <u>Specification of "comparable companies" to serve as the basis of performance evaluation</u>. Grouping the utilities would, according to the authors, control for the differences among them and therefore allow a comparison of rate performance across firms. The problems with delineating comparable groups of firms centers on defining the factors that make firms similar, as well as the context of similarity. In fact, it would be extremely difficult to select a set of quantifiable factors that would group firms according to operating similarities that affect unit costs but are strictly beyond management control. The factors proposed by RCG -- generating capacity, load factor, historical growth rate, taxes and pattern of use by class -- would not create similar groups; instead, they would lead to groupings alike in some ways that management could possibly control, such as load pattern, and different in some ways that management cannot control, such as availability of fuel and purchased power.

It would be extremely difficult to group companies to allow a fair and equitable comparison because of the variety of factors, endogenous and exogenous, that affect utility operations. The unique characteristics of individual companies have historically created difficult analytic problems in efforts designed to develop groupings of "comparable companies" for a variety of purposes. The authors have not sought to demonstrate that it can be done for a significant number of utilities, or, indeed, for any specific utility.

3) <u>The use of average revenue per kilowatt hour (R/kWh) as the performance criterion</u>. R/kWh may vary substantially between utilities and over time for causes that bear no relation to management efficiency. Among such causes are: (1) geographic location which determines the availability of fuel and purchased power, (2) changes in weather conditions that are beyond the control of utility management and may affect both load and hydro generation, (3) demand fluctuations reflecting the business cycle, (4) political or other developments affecting regulatory policies and practices, and (5) uncontrollable changes in costs such as taxes, fuel prices and purchased power rates. In addition, since R/kWh is significantly influenced by regulatory policy, comparative results may be more reflective of the fact that utilities (in the "comparable group") are located in different (state) regulatory jurisdictions than the relative efficiencies of their respective managements.

4) <u>The inclusion of the full effects of past management decisions in the measure of comparative performance</u>. In the selection of "comparable companies," RCG would not account for previous management decisions. RCG states that the performance measure should reflect previous decisions, which "is consistent with designing an incentive program to promote

good long-term cost performance."* The nature of an electric utility is such, however, that a large part of its total cost at any given point in time is determined by management decisons made many years in the past. Evaluation of current management on the basis of a system that focuses upon decisions made in the past, i.e., that are beyond the control of present management, may be ineffective in strengthening management incentives for innovation and efficient operation. The evaluation should instead be based upon how the current management handles present and future decisions, some of which, of course, may be influenced by past management choices.

D. Evaluation

While there are difficulties with specific elements of the proposed plan, individual utilities may develop similar plans that are useful in their particular circumstances in stimulating improved management efficiency by making various modifications. One such modification would be altering the R/kWh measure to a total cost measure (including a standardized cost-of-capital instead of return-on-capital) reduced by elements of cost deemed uncontrollable (by management), such as fuel prices, local taxes, etc.

No single incentive compensation plan can be applicable to all utilities. Indeed, the heterogeneity of utility situations and needs is likely to require that plans submitted by differ-

---

*Ibid., p. 2.18.

ent utilities will differ considerably from one another. To achieve the overall objective of such plans, it is only necessary that the plan employed by an individual utility be reasonable for that utility, i.e., that it offer a strong likelihood that the cost savings to be derived from the improved efficiency stimulated by the plan will exceed the costs of implementation of the plan. Progress toward the development of plans that meet this standard should not be allowed to founder on the failure to achieve perfection, while the search for the elusive ideal of a single plan meeting the needs of all companies continues indefinitely.

Because consumers would be required to bear the cost of such payments, the authors state that "FERC must be directly involved in setting the aggregate level of potential and actual award payments..."* The plan, as proposed, calls for the funding of the incentive award costs by ratepayers. Indeed, it is suggested that a rate surcharge be put into effect at the beginning of the performance year and revenues therefrom put into escrow to finance the incentive awards when the actual amounts are determined. Figures compiled by the authors suggest, however, that the cost of their recommended program would be quite small (even without consideration of any savings

---

*Ibid., p. 4.14.

resulting from increased management efficiency)* so that the need for special regulatory control or oversight is dubious.

IV. Critique of Alternative Programs

This section includes comments on the two alternative programs proposed by the authors.

A. Construction Cost Control Program

1. Summary of Proposed Program

The authors propose a supplementary Construction Cost Incentive Program (CCIP) that links both an incentive/penalty rate-of-return mechanism and a management compensation plan for construction program managers to a utility's cost control performance on major construction projects. Under the proposed program, the rate-of-return on common equity allowed on investment in large construction projects, when such projects are completed and included in rate base, would be raised above a pre-specified rate if the actual costs of the completed project were less than the cost projected by the utility when the project was commenced. The allowed return on equity would be decreased if the actual costs were above those initially projected. Utility managers responsible for completing projects at less than projected costs would presumably receive cash rewards as well. The projected cost would be computed in constant dollars and adjusted for inflation. Adjust-

---

*The maximum before-tax cost of their program appears to be in the order of magnitude of 0.03 to 0.10 mills per kWh of wholesale and retail sales. Actual costs would, of course, be less than this. Ibid., p. 4.16.

ments of the projected cost over the construction period would also be made to reflect changes in the scope of the project.

2. Positive Features

The specific purpose of the CCIP is to create incentives to avoid cost overruns in the construction of new power plants. It reflects recognition of the fact that the cost overrun experience in a number of major power plant construction projects in recent years may indicate a need for some sort of additional incentives to avoid such overruns. Indeed, several utilities have taken steps to strengthen such incentives among construction personnel by way of incentive compensation plans for such personnel. Similar plans have been created for contractors and vendors of major construction projects.

Adjustments to projected costs to reflect inflation should be counted as a positive feature of the CCIP. Perhaps even more important are adjustments to reflect changes in project scope. These changes presumably include addition of safety or environmental requirements imposed by regulatory agencies, delays in receipt of appropriate governmental authorizations, emergencies and other developments that affect project costs but that are beyond management control.

3. Problems and Limitations

The need for installation of a new incentive program to insure that large construction projects are completed at the lowest possible cost is dubious. Utilities, like jected values so that the utility would not over- or under-collect its fixed charges. Finally, special (non-automatic) adjustments may be authorized by regulatory agencies under certain circumstances such as: (1) addition of a new large unit, (2) substantial changes in capital market conditions, (3) a roll-over of debt at substantially different interest rates, and (4) loss of a major generating unit for reasons beyond management control.

Cost reductions achieved by the utility during the 3-5 year period would benefit ratepayers by way of automatic periodic reductions designed to reflect some portion of estimated productivity improvements and, ultimately, by way of the rate adjustments made in the periodic rate cases.

2. Positive Features

This plan is proposed as a possible alternative to the Rate Control Incentive Program as a means of stimulating management to seek to improve productivity and thereby minimize rates charged to customers. The device employed requires a substantial extension of the typical period between rate cases. Thus, reductions in costs that management can effect during such periods would increase earnings until the next rate case (presumably a much longer period than is typical under current circumstances). The substantial reduction in rate cases contemplated under the program appears desirable since the burden and cost of such proceedings can be quite substantial.

the expense of higher costs of replacement and maintenance in the future. If the plant is brought on line under budget by increasing life cycle costs, ratepayers' interests would be adversely affected.

4. Evaluation

These difficulties, notwithstanding, individual companies may see some merit in this type of program to avoid or minimize costs of overruns in the construction of new power plants. Nevertheless, the design and implementation of any such program is clearly the responsibilty of utility management and its Board of Directors.

B. Automatic Rate Adjustment Mechanism

1. Summary of Program

The authors propose an alternative program (ARAM) which would extend the period between rate cases to 3-5 years, and automatically adjust rates to reflect external changes in the prices of variable factor inputs. This would strengthen management incentives to minimize costs and thereby maximize profits over the period. Under this program, rates would be set to cover costs for an initial future test period. Then, every 3-6 months, the variable component of rates would be automatically adjusted according to changes in externally observed indices that follow the market prices of variable inputs -- fuels, labor, other materials and supplies, and purchased power. Automatic adjustments would also be made based on load and energy requirements that differ from pro-

a) <u>It may increase the cost-of-capital to the utility</u>. Since the incentive mechanism is the authorized rate of-return, the CCIP creates the possibility of reduced earnings due to cost overruns. This simply increases the degree of risk stemming from possible cost overruns so that the costs of both debt and equity capital may be adversely affected. For an industry already having financial difficulties as a result of inadequate rate-of-return allowances, further increases in capital costs would be especially disadvantageous.

b) <u>It may create management incentives to avoid projects for which the risk of cost overruns is greater</u>, even though this leads to the construction of projects that are not preferable from the standpoint of overall cost minimization. An example might be the construction of a coal-fired plant rather than a nuclear plant because the risk of overruns on the nuclear plant is greater, even though construction of the nuclear may be much more likely to result in lower life cycle costs after allowing for the relative risk of overruns.

c) <u>It may create management incentives to be conservative in estimating the projected cost of a project in order to improve the chances for higher rate-of-return allowances</u>. This would, of course, tend to defeat the purpose of the program. It might also lead to sub-optimal planning decisions as well as regulatory certification problems.

d) <u>It may create incentives for construction of facilities in such a way that initial costs are minimized at</u>

all other companies, seek to minimize their costs. From the standpoint of the utility, the desire to minimize rate increases associated with the cost of new construction is already more than adequate incentive to complete power plants promptly and at minimum cost. For example, the size of the rate increases necessary to recover costs of some new plants just coming on line are relatively large because of failure of the regulatory agencies to permit CWIP in rate base. Some regulatory agencies have sought to find ways of deferring some of this impact to future years. In general, however, deferral of rate increases to cover construction costs is not in the best interest of the utility, and can best be avoided by minimizing the completed cost of the plant. Second, the inadequate rates-of-return that continue to be authorized and earned by electric utilities -- in most cases, below the market cost of capital -- create a "reverse Averch-Johnson effect."* That is, an inadequate rate-of-return creates incentives to minimize new investment since it has the effect of reducing the total market value of the utility.

There are a number of additional problems with the CCIP, most of which are recognized by the authors. These include the following:

---

*Peter Navarro, <u>Long Term Consumer Impacts of Electricity Rate Regulatory Policies</u>, Prepared for U.S. Department of Energy, January, 1983, pp. 21-28.

An additional beneficial feature of the ARAM which is not incorporated in either of the RCIP or the CCIP is its forward looking approach to ratesetting. By using a prospective test period to set base rates and adjusting them every 3-6 months to reflect changes in external indices of the costs of their variable inputs (i.e., fuel, labor, purchased power and other materials and supplies), the ARAM could reduce the lag and uncertainty regarding recovery of these costs. It also provides for special adjustments to rates to account for individual circumstances.

The plan would simulate the market circumstances faced by a competitive enterprise (at least for a period of time) more closely than either of the plans discussed above. As a result, according to the authors, "...a firm would be encouraged to achieve least-cost production, thereby maximizing its profits against the externally determined prices for its products."*

3. Problems and Limitations

There are, however, a number of problems with the plan, some of which are recognized by its authors. Among these problems are the following:

a) Exclusion of capital costs may create a bias toward capital improvements. The plan does not include capital costs in the rate adjustment index because, according to the authors, an acceptable method of indexing capital-

---

*Resources Consulting Group, Inc., *op. cit.*, p. 5.24.

related costs has not been developed. This may have the effect of biasing management decisions concerning capital additions.* It may also unfairly penalize utilities during periods of rising capital costs to the extent that a special rate adjustment cannot be obtained to cover such changes in capital market conditions. Regulatory agencies are likely to be more expeditious in making special adjustments during periods of falling capital costs.

b) Special (non-automatic) adjustments may lead to costly disputes. The provision for special adjustments to deal with the four types of circumstances described above may lead to controversy and litigation of a magnitude sufficient to largely offset any cost reductions stemming from reduced frequency of regular rate cases.

c) It may create incentives which conflict with quality of service objectives while attempting to reduce costs-of-service during the period between rate cases.

d) It may increase the cost-of-capital to any given utility, since it would increase the possibility of lags in rate increases to cover cost increases.

e) The demand control function that rates should perform may become more distorted than under current

---

*For example, if a firm can justify a rate adjustment as a result of a capital addition, this may create an incentive to substitute capital for variable inputs covered by an automatic index.

regulatory procedures to the extent that prices are relatively fixed for a lengthy period.

4. Evaluation

These difficulties are not necessarily insurmountable. There is no reason to suppose, for example, that development of an acceptable method of indexing capital-related costs of a firm is beyond the realm of possibility. Similarly, it may be possible to develop an acceptable index of service quality or some other means of assuring that quality of service does not suffer as a result of incentives created by use of some variation of ARAM. In addition, to the extent that ARAM results in rates that are fixed for substantial periods subject to adjustment by specified (and to some extent predictable) indices, regulatory uncertainty is reduced so that any adverse effect on cost-of-capital is substantially mitigated.

V. Summary and Conclusions

Despite the conceptual problems and practical limitations, EEI believes that each of the proposals contained in the subject study has sufficient merit to warrant further consideration. The proposed Rate Control Incentive Program raises some interesting ideas relating to incentive regulation. Nevertheless, any compensation plan used to reward management for improved efficiency can only be a viable option if designed and administered by individual utilities. Such a program should not be developed and administered by FERC, or by the State commissions. Also, we believe that classification of utilities into comparable groups via a set of factors will not reflect the spectrum of differences between utilities that are beyond managment's control. Additionally, the use of average revenue per kilowatt hour to compare performance will reflect variation among utilities that has no relation to management performance.

In seeking to reduce or prevent cost overruns in the construction of large power plants, there may be a few cases in which the proposed CCIP, based on rate-of-return, has been shown to be an effective program. However, using rate-of-return as the incentive mechanism may adversely affect the cost-of-capital of participating utilities and, therefore, negate any benefits from the program.

The ARAM plan appears to be a proposal with various appealing aspects. However, further research is needed in such areas as: (1) the development of capital cost indices, (2) methods of assuring that special adjustments can be made when needed while avoiding the need for frequent rate proceedings to deal with requests or complaints relating to adjustments, and (3) the effects of various ways of automatically modifying rate designs between rate cases, as cost and load conditions change.

It must be emphasized that implementation of any incentive program is primarily a task for the individual utilities. The FERC, and the State commissions, if they have general concerns about the form and substance of incentive programs, may find it desirable to put forth general guidelines to be considered by the utilities in developing individualized programs. Beyond this, the role of regulators should be one of cooperation with the utilities, and coordination among themselves to insure that they are jointly supportive of incentive programs sponsored by the utilities they regulate.

EEI commends the FERC for the leadership role that it has taken in commissioning this important study of alternative approaches to creating incentives for greater economy and efficiency in a regulatory context. It is certainly a matter that is worthy of further study with consideration of the issues raised in these comments and by EEI's member companies. We will be pleased to continue to work with the FERC in further consideration of these issues.

COMMENT ON

"INCENTIVE REGULATION IN THE ELECTRIC UTILITY INDUSTRY"

This analysis was sponsored by the

ENERGY RESEARCH GROUP*

Prepared by

John H. Landon
Vice President
National Economic Research
Associates, Inc.
1800 M Street, N.W.
Washington, D.C. 20036

* A list of member companies is attached. Not all agree with all the comments contained herein.

ENERGY RESEARCH GROUP
MEMBER COMPANIES

Carolina Power & Light Company
Houston Lighting & Power Company
Long Island Lighting Company
Middle South Utilities, Inc.
New England Electric System
Pacific Power & Light Company
Pennsylvania Power & Light Company
Public Service Company of New Mexico
Public Service Company of Colorado
Puget Sound Power & Light Company
San Diego Gas & Electric Company
Tampa Electric Company
Virginia Electric & Power Company
Wisconsin Electric Power Company

TABLE OF CONTENTS

TABLE OF CONTENTS

I. CONCLUSIONS AND OUTLINE

Developing a method to provide electric utilities greater incentives to implement programs which maintain or improve efficiency is a laudable, though not novel, objective. The Federal Energy Regulatory Commission (FERC) Staff should be encouraged to continue to explore alternative means to attain this goal. The report by the Resource Consulting Group, Inc. (RCG) reflects a great deal of thought on this complex topic and advocates a program which incorporates several desirable features. However, while the authors should be awarded high marks for recognizing many of the conceptual and practical problems of measuring utility efficiency, their recommended approach does not offer the required solutions. Indeed, the resulting recommendations offer little that is new in dealing with any of the hard problems attendant to measuring the relative efficiency of electric utilities. We find the following to be the principal strengths and weaknesses of their analysis.

A. Strengths

1. Recognition of the dangers and limitations of relying on a measure of firm efficiency which concentrates on a limited segment of the firm's operations (e.g., heat rate).

2. Recognition that both the level of performance achieved during a given year and changes in performance over time need to be considered.

3. Recognition of the need to adequately compensate utility executives for the quality of their efforts.

4. Recognition of the desirability of separating the performance of management from the consequences of external factors.

5. Emphasis on developing measures which will not distort the price signals perceived by utility management.

B. Weaknesses

1. Any ranking of utilities that indicates below average performance levels is likely to have unintended and adverse effects on the regulatory treatment of utilities, thus leading to one of the major problems the authors wish to avoid. It is unlikely that a state commission that is sensitive to alleged imprudence or to political considerations could ignore an unfavorable performance ranking, however poorly conceived or administered, in determining allowable costs or rates of return. If commissions do use poor performance rankings in regulatory decisions beyond the context of the incentive program, the adverse effects on costs of capital, which this study seeks to avoid, will occur as a result of implementation of the authors' plan.

2. The proposed method of grouping utilities for comparison fails to recognize many factors which cause substantial variations in measured performance beyond the control of present management. Beyond this, as discussed in detail below, it is not primarily the classification method that is wrong but the underlying variation in relevant factors that makes classification into homogenous groups of ten or more utilities impossible.

3. Even given a reasonable grouping of utilities, the proposed measure of performance--average revenue--will vary substantially within the period under consideration for reasons unrelated to the quality of management performance. Among other factors, average revenue will be affected by:

a. Cyclical fluctuations in demand;

b. Timing of major construction projects;

c. Changes in state regulatory policy;

d. Shifts in relative fuel costs;

e. Availability of low-cost hydroelectric energy; and

f. Timing of state and federal rate relief.

4. The use of average revenue as the measure of performance may bias management against major investments that have long but economically attractive payoffs. It also may bias management in favor of low depreciation rates, flow through accounting or any other rate treatment that shifts costs forward (e.g., not normalizing nuclear decommission costs).

5. Lags in data availability and inconsistencies in reporting are likely to impede the implementation of the program.

6. The high degree of cooperation among utilities, which has allowed the rapid spread of technological advances and significant operating savings, may be impeded.

7. Performance measures will be arbitrary, to a large extent, because they will be heavily dependent upon the particular statistical formulation used.

8. Substantial ratepayer-funded bonuses to utility managers may not be acceptable to state commissions.

9. The proposed concept of a "management incentive compensation program" represents a basic change in philosophy as regards the regulation of investor-owned utilities. Regulatory commissions are now charged with treating investors in these utilities fairly and protecting the interests of customers. Shareholders (investors) now elect boards of directors responsible for the selection and motivation of management <u>and</u> charge that management with appropriate representation of the interests of investors.

The proposed incentive scheme would place regulators in the position of determining a potentially significant portion of managerial salaries exclusively on the basis of the interests of ratepayers as they perceive them.

Allowing the company directors to determine the method of distributing the bonus pool mitigates but does not eliminate the intrusion of regulators in what traditionally has been a responsibility of company directors as representatives of the stockholders.

In summary, the recommended incentive program is not likely systematically to identify and reward the most effective utility managers and it may well impart significant and unintended biases. The authors offer no real solutions to any of the widely recognized difficulties of performance measurement. These negative aspects should be weighed against the positive incentive effects that may be produced by establishing a system of rewards.

The two additional programs of incentive ratemaking suggested by the report likewise are of dubious value. The suggested supplementary program to reward construction managers and utilities whose major capital projects are completed within budgeted costs appears difficult to implement and would create rewards for counterproductive "gaming" of the system. For example, it would provide managers with a strong incentive to inflate construction cost estimates to insure that projects will be completed at or below budgeted costs. The potential substitute program of indexing rates has desirable features but is not presented in enough detail to evaluate the likely consequences.

In short, the report provides a useful contribution to the evolving literature on incentive ratemaking but does not present a workable program for implementation. While it does a good job of outlining the objectives of an incentive program for utilities, and correctly identifies the problems of many alternatives, its approach is far too simplistic to insure either fairness or correct incentives. This is not to say that the proposed plan or some similar one could not produce some benefits. A program of incentives would not have to be perfect to be worthwhile. The average-revenue-based standard suggested by the authors, however, has a number of critical flaws. These flaws render the probability of a net benefit very low indeed.

C. General Outline

The remaining sections of this paper explain the basis for our generally negative assessment of these proposals. **Section II** (pages 7 to 25) demonstrates that the authors' proposed average revenue performance comparison method does not take sufficient account of cost differences caused by factors beyond the control of management. It further explains why identifying and grouping utilities into homogenous groups for performance comparisons cannot be accomplished either by the methodology suggested by the authors or by any other method consistent with their general approach. It emphasizes that a proposal designed to reward present management for performance must isolate its performance contributions to be either fair or effective. The methods suggested by the authors would mix cost differences caused by geographic and demographic characteristics of utility service areas and the decisions of past managers of the utility, made over many years in circumstances much different from those that now prevail, with operating and investment decisions of current managers. The resulting stew is unlikely to bear any systematic relationship to the contributions of the utilities' current managers who would be rewarded or punished.

Section III (pages 26 to 32) demonstrates that the average revenue comparisons advocated by the authors would be warped by differential changes in local input markets and regional changes in the patterns and levels of electric demand. These changes, also beyond the control of management, render the resulting performance comparisons even more suspect. **Section IV** (pages 33 to 38) shows the perverse incentives an average revenue standard would provide to make accounting changes as well as investment decisions to enhance short-term efficiency ratings even at the expense of the long-run interests of ratepayers and stockholders. **Sections V, VI, and VII** (pages 39 to 40, pages 41 to 42, and pages 43 to 46) discuss the potential for misuse of performance ratings and other disadvantages of the proposed measure including (1) time lags in measuring performance, (2) reduction of the incentives for cooperative behavior, and (3) sensitivity of the measure to the precise specifications of the rating scheme. **Section VIII** (pages 47 to 48) discusses the contribution of the report's discussion of the average revenue proposal and provides our conclusions.

Section IX (pages 49 to 57) offers our evaluation of the suggested construction cost incentive program and the proposed program of increasing regulatory lag through the tying of electric rates to indices of input costs. We find that the proposed construction cost incentive program would be burdensome to administer, would impose an asymmetric risk on utilities, would bias decisions away from capital-intensive or innovative projects, and would provide incentives to game the system through inflated cost estimates.

The concept of the proposed rate indexing scheme is the most promising of the suggested incentive methods but it is not spelled out in enough detail to be evaluated fairly. We suggest a number of specific questions which would have to be answered to make rate indexing, coupled with regulatory lag, a fair and effective tool for promoting efficiency.

II. GROUPING UTILITIES FOR PERFORMANCE COMPARISON

A. Introduction

The report suggests that utilities be classified into groups of at least ten firms whose levels and changes in average revenues per kilowatt-hour can fairly be compared. Utilities within each group should be comparable in factors which affect unit costs but are outside of the control of the utilities' management. Generating capacity, load factor, load growth, the percentage of sales to residential and commercial customers, environmental requirements, and state and local tax burdens are specifically identified by the authors as factors to be considered in making the groupings. The authors recommend that all differences among utilities which result from decisions of previous management (such as the size, type, and fuel of generators) be excluded from the exogenous circumstances used to classify utilities.

There are four fundamental problems with this suggested approach to comparison grouping:

1. The factors identified by the authors are not entirely exogenous—that is, to some extent they are subject to management control.

2. All factors which substantially affect costs and are exogenous to management decisions cannot be identified and quantified.

3. The exogenous factors which can be quantified vary over such a wide range that it is doubtful that groups of 10 relatively homogenous utilities can be identified.

4. Even if all exogenous factors were identified and quantified and homogenous groups were drawn based on them, differences in factors beyond the control of <u>current</u> management will result in differences within groups which make the comparisons useless in identifying good performance.

B. Identifying and Quantifying Exogenous Factors

The factors outside of the control of either the present or prior management of an electric utility which are likely to affect substantially the level of costs, and thus average revenue, can be divided roughly into four categories:

1. Those that relate to the general cost of any business operating within the areas served by the utility;

2. Those that affect the range of choice available in the method of generating electricity;

3. Those that affect the cost of transmitting and distributing electricity; and

4. Those that affect the pattern of electricity use.

The costs of operating a business in a specific geographic area will be governed to a large extent by (a) the costs and availability of factors of production, (b) the distance to markets and suppliers, and (c) the level of services, degree of regulation and costs of local government. The exogenous factors listed by the authors of this report account for only a portion of (c). Omitted factors include area wage rates, educational level of the labor force, weather conditions, proximity to major population centers or sources of raw materials, access to low-cost forms of transportation, land availability, and cost, type and availability of government services. Quantifying these factors, as well as some of those the report does mention (e.g., the burden of environmental regulation), would present difficulties. Omitting them, on the other hand, is almost certain to result in unintentional biases of substantial magnitude.

It is important to recognize that electric utilities are fundamentally different from most competitive industries in that their managements do not have locational choice. It may make sense to make national comparisons of the costs or profits of steel or aluminum companies. After all, their managements are free to locate facilities to take advantage of low-cost resources, access to transportation, nearness to markets, favorable labor markets and other features which vary among areas. Electric utilities' managements do not have this option. The management of the Bonneville Power Administration is not responsible for choosing a location in which it could exploit the low-cost potential of abundant falling water nor can the management of the Consolidated Edison Company be faulted for choosing to serve a highly congested urban market far removed from sources of low-cost coal, natural gas or water power resources. An electric utility is required to provide service to customers in its own specified service areas. It should not be blamed or credited with cost consequences imposed by its location.

The authors of this report choose to treat the mix of generation plants as a management decision and therefore propose not to consider characteristics of the mix in placing utilities into comparison groups. This, however, ignores major differences between utilities in entirely exogenous factors which give them decidedly different options. Utilities in areas of abundant hydroelectric potential, those whose service areas span important coal fields, those located in major oil and gas production centers, and those with access to low-cost water transportation are presented with choices which are markedly different from those of utilities not similarly situated. Thus, even if we agreed that fuel mix used to generate electricity is in control of current management (which we do not), there are numerous clearly exogenous factors which influence its choices and the resulting costs. (In a technical sense, utilities face different production functions for their homogenous output). Any comparison of utilities' relative average revenues which does not allow for these differences is flawed in a very major way.

The costs of transmitting and distributing electricity are determined in large measure by the geographic and demographic characteristics of the utility's service area. The level and variation of population density accounts for much of the difference in distribution costs among utilities and is virtually totally outside the control of current management. The size and dispersion of population centers within the service area and the proximity of generation sites to these population centers have a major influence on the required level of transmission investment.[1] None of these exogenous influences is suggested as classifying characteristics by the authors of the report. Instead they suggest adding line losses to kilowatt-hour sales in calculating average revenue. While this may serve as a proxy for a portion of the variable cost differences associated with serving very sparsely as opposed to densely populated areas, it does not measure at all the additional investment costs required or the added maintenance and repair costs associated with service to rural areas. The additional costs associated with such service are likely to be much more than proportional to the increase in line losses (the assumption implicit in their suggested adjustment).

In addition to not adequately reflecting the added costs of serving sparsely populated areas, the adjustment suggested to allow for differences in density does not reach increased costs occasioned by service to highly congested

---

[1] The type and dispersion of fuel resources in an area also affect the optimal scale and location of generation plants. Utilities in areas with abundant gas supplies had the option of constructing many small units close to load centers. Those dependent on coal frequently found fewer and larger units more economic with a consequent increase in transmission requirements.

areas. In such areas, right of way, maintenance and repair, and construction costs all are very high. Nor does the proposed adjustment account for differences in the extent to which the utility has been forced by demographics or legislation to install more expensive underground lines and transformers.

The pattern of electricity use is a major factor in determining the level of average costs (and thereby average revenues). The pattern of use tends to be both exogenous to utility management and variable among the areas served by electric utilities. Pattern of use is a broad term which embraces a number of elements, each of which has an important influence on utility costs. The shape of a utility's load varies on an hourly, daily, and seasonal basis with the need for electricity of its particular mix of customers. High degrees of load variation or low levels of use per customer result in high relative costs per kilowatt-hour. Sharp peaks in demand generally are more expensive to serve than prolonged peaks at the same level. Loads with strong seasonal and/or cyclical patterns result in higher average cost levels. These differences in load patterns are influenced in large measure by exogenous factors such as:

1. Climate in the area;
2. Type and variety of commerce and industry served;
3. Price and availability of alternative sources of energy in the area;
4. Level of per capita income in the area served; and
5. Size and diversity of the utility's service area.

Load patterns also are affected by the utility through load management programs, rate design, and cost allocation procedures. While these are frequently the result of management decisions, the actions and requirements of regulators add a potentially significant exogenous element.

The authors at least partially recognize the importance of load patterns in determining costs and suggest "load factor" as an exogenous factor to be used in classifying utilities into comparison groups. While this is useful, it must be recognized that the ratio of average to peak demand is not completely exogenous, since it is affected by rate policy (e.g., peak responsibility pricing). Moreover, it does not measure such important cost-related factors as use per customer, and reflects very imprecisely the patterns of loads that affect costs. For example, it does not measure the duration of peak demands or the number of periods during which the utility's loads are at or near peak levels. These factors are very significant in choice of generating unit size, design and fuels and thereby in determining costs per kilowatt-hour. Much more thought would be required, and much more complex measures would have to be developed, to measure adequately the exogenous factors which affect average revenues through load patterns.

The failure of the suggested methodolgy to deal adequately with the exogenous factors that determine much of electric utility costs is not surprising. Previous efforts to identify characteristic variables that can be used to classify utilities into comparable performance groups have been made and have failed.[2] In this area the authors offer no significant advance toward effective and fair performance measurement.

---

[2] J. Edward Smith, The Measurement of Electric Utility Efficiency, September 1975 and The Measurement of Electric Utility Cost Performance: A Proposed Methodology, February 1976, National Association of Regulatory Utility Commissioners, Washington, D.C. (The second report contains responses of utilities and commissions challenging the methodology and conclusions of the first study.); Bernard W. Tenenbaum, The Measurement of Relative Productive Efficiency Among Privately Owned Electric Utilities, Ph.D. Dissertation, University of California, 1980; and U.S. Federal Power Commission, Performance Profiles: Private Electric Utilities in the United States, 1960-1970, Washington, D.C., 1973.

C. Difficulties in Creating Homogenous Groups of Utilities

Even if we were to accept the authors' definition of the exogenous factors to be used in classifying utilities, the groups that would be created would contain utilities with such marked differences that average revenue comparisons among them would have little meaning. Moreover, it is unclear how the authors would develop the initial list of utilities to be classified.

The report suggests that groups of at least 10 utilities be formed based on such exogenous factors as generating capacity, load factor, load growth, percentage of sales to residential and commercial customers, environmental requirements, and state and local tax burdens. The principal mechanism suggested for making the classification is the use of either principal components or factor analysis to create a measure of common characteristics which then can be used to sort utilities into relatively homogenous groups through cluster analysis.[3] As a partial alternative to this procedure they suggest the use of an expert panel. Before examining the variations among utilities in the suggested classifying factors and the suggested methodology for using them to group utilities, it is useful to begin our discussion by considering how the utilities to be clustered would be identified in the first place.

Because the authors suggest both that Form 1 data be the basis for comparison and that state commissions be actively involved in the incentive program, we assume that each privately owned utility that files a Form 1 would be included. (The West Virginia Public Service Commission is certainly more interested in the average revenue of the Appalachian Power Company than it is in the combined results for the seven state American Electric Power Company

---

[3] A brief description of cluster analysis appears as Appendix III to this comment.

system). This, however, raises some real difficulties in making meaningful comparisons. Large integrated electric utility holding companies, such as American Electric Power Company and Texas Utilities, build generating units and transmission systems sized to meet the integrated loads of their constituent companies. To compare companies of the same size, therefore, the members of highly integrated holding companies clearly should be aggregated. On the other hand, some holding companies are less completely integrated (e.g., the Central and Southwest Corporation) and for many purposes should be considered as separate utilities. Several utilities also have relatively small subsidiaries that file a separate Form 1. Should these be considered alone or aggregated with the parent? If integrated holding companies are considered as units, should not nonaffiliated utilities who are members of highly integrated pools such as the New England Power Pool or the Pennsylvania-New Jersey-Maryland Interconnection also be combined? The authors of this report do not address these difficult questions which, though not insolvable, require more thought than they have been given in the present proposal.

Assuming that a reasonable list of utilities is derived, and that they are classified using the authors' stated criteria, the resulting groups will include utilities with substantial variations in these and in other largely exogenous determinants of average revenue. To illustrate this we have performed the following simple experiment using 1980 Form 1 data: (1) list the largest ten utilities in generating capacity; (2) beside each, enter that utility's rank using the other quantifiable criteria suggested by the authors (environmental burden is not capable of quantification based on any available data of which we are aware); and (3) enter each utility's typical residential electric bill for 750 kilowatt-hours per month. The results of this test appear in Table I below.

TABLE I

COMPANIES RANKED BY RCG CRITERIA

Utility	Rank in Terms of					
	Generating Capacity (1)	Load Factor (2)	Growth in kWh Sales (3)	Percent Sales to Residential and Commercial Customers (4)	Tax Burden (5)	Typical Residential Electric Bills (750 kWh) (6)
Commonwealth Edison Co.	1	149	140	60	42	13
Southern California Edison Co.	2	126	146	69	150	57
Houston Lighting & Power Co.	3	73	19	143	127	82
Florida Power & Light Co.	4	134	35	4	59	113
Georgia Power Co.	5	128	112	124	136	168
Duke Power Co.	6	86	107	123	104	144
Pacific Gas & Electric Co.	7	122	133	26	181	54
Detroit Edison Co.	8	82	171	105	119	56
Virginia Electric & Power Co.	9	130	65	64	128	162
Consolidated Edison Co. of New York	10	163	131	6	7	1

It is apparent from Table I that utilities that are large in terms of generating capacity are far from homogenous with respect to the other suggested classification criteria. A similar result occurs if any of the other criteria are used to make the initial ranking. When the lack of uniformity of large utilities in other characteristics is added to the fact that even in generating capacity there is a 54 percent variation among the 10 utilities with the highest levels, the difficulty of deriving a group of utilities homogenous in all exogenous characteristics becomes apparent. For example, a group of the largest utilities constrained to be within 25 percent of each other in load factor would contain one member three and one-half times as large as another. A group of the largest utilities constrained to no more than 25 percent variation in both load factor and growth rate would require that the largest member be six times as large as the smallest.

The ranking in typical electric bills, shown in the last column of Table I, is also illustrative of the degree of heterogeneity among utilities of similar size.* The rankings in average revenue of the 10 largest electric utilities vary from 1 to 168 and show no systematic relation to the presumed exogenous factors. The residential bills for 750 kilowatt-hours per month residential usage of these companies vary in absolute terms from $43.33 (Georgia Power Company)

---

* As ranked by the Public Service Company of Colorado from data obtained from the Department of Energy's Typical Electric Bills, January 1, 1982.

to $113.73 (Consolidated Edison Company). It is clear that this large a difference is not explained by the exogenous factors suggested by the authors.[5]

The sophisticated statistical methodologies suggested by the authors cannot overcome the degree of heterogeneity among electric utilities. Using their recommended approach and their suggested exogenous characteristics, for the year 1980 we produced "clusters" of utilities to determine the degree of uniformity in exogenous characteristics which would result. Specifically, we used 1980 Form 1 data for megawatt capacity, load factor, growth in kilowatt-hour sales between 1970 and 1980, residential and commercial sales as a percentage of total kilowatt-hour sales, and taxes other than federal income taxes as a percentage of net plant. The utilities used in the analysis include all Class A and B privately owned electric utilities excluding only those for which any of these exogenous variables takes on a meaningless value (e.g., no load factor or load factor greater than one) or those missing critical data.

The exogenous variables for the utilities were combined using unweighted principal components analysis. This technique is used to combine variables that are too numerous to be used separately or are so strongly dependent on each other that they are not truly independent variables. The "principal components" are composite indices of the original variables, constructed to reflect as much of the variation contained in the original set of data

---

[5] The difference would be much larger for utility groups including members from both the Northeast and the Pacific Northwest. Due largely to the differences in cost between oil-fired generation and low-cost federal hydroelectric power, differences between these regions are enormous. For example, in Cluster 4 (Appendix I, page 4), the range of typical residential electric bills is from $20.48 (Puget Sound Power and Light Company) to $66.82 (Hartford Electric Light Company).

as possible. These indices have the desirable statistical property of relative independence from one another such that they are useful for further analysis.[5]

The principal components indices then were used in cluster analysis to define the groups of utilities. Cluster analysis is a technique used to classify observations into smaller groups having relatively homogenous characteristics. In this case, the analysis used four principal components as the basis for establishing the groups. This method begins by combining the two utilities whose indices are most similar; then, given that choice, the two utilities that are next most alike are combined. This process is continued, either pairing utilities or adding utilities to previously determined groups, until all utilities have been combined into a single group containing the entire sample. The critical decision, which must be made by the researcher, is when to stop the process. Deciding when to stop requires either a satisfactory statistical test to measure the similarity within groups and dissimilarity between groups, some "a priori" rule relating to cluster size, data manageability, or some other condition deemed important. Unfortunately there exists no theoretically justified test or method for choosing the optimal number of clusters.

The authors suggested that utilities be grouped in clusters which contain at least 10 firms. Using this general criterion the clustering process was allowed to continue until as many firms as possible were in groups of 10 or more, without allowing group size to rise above 25 to 30. This was difficult because the clustering program classified most utilities in small clusters of two, three or four companies until the total number of clusters was quite small. For

---

[5] The authors suggest that "factor analysis" could be used in place of "principal components" as the first stage of the sorting process. We did not attempt this alternative formulation.

example, with 30 clusters, 85 companies remained alone or in groups of seven or fewer. Further reduction in the number of clusters, on the other hand, results in large groups of 20 or more utilities, near the point of being too large. We decided to use 20 clusters which seemed to offer the best compromise between minimizing small clusters that must be "forced" into groups of 10 and maintaining groups of manageable size. Even at this point in the clustering process, a total of 49 firms, grouped in 13 small clusters, had to be "forced" or arbitrarily gathered into three larger groups of more than 10 firms each. Because these groups were not chosen by the statistical process, they may be less homogenous than are the others. However, continuing the analysis until there were only ten clusters would not have improved matters at all. At that point some 30 utilities remained in groups too small by the authors' criterion, but one group had grown to a membership of more than 100.

Appendix I identifies the utilities classified into each of 10 "clusters" using the process described above. For each utility it also lists the value of each of the presumed exogenous variables which were used, through principal components and cluster analysis, to create the groupings. These appear to be the most homogenous groups that can be obtained based on these exogenous variables and this grouping technique. While we followed the authors' suggested methodology as closely as possible, they did not provide sufficient guidance to allow us to create the clusters without some independent judgment. We had to choose the number of principal component indices created as well as the number of final clusters. The quality of the resulting groups does not appear to change with small changes in these judgments within the general framework provided by the report.

computer output, great controversy over defining exogenous factors and methodology and, in general, a long and costly jockeying for position would result. The classifications, when finally obtained, are certain to be, not just imperfect, but so arbitrary as to be unlikely to satisfy the contrasting interests of utilities, state regulators, and the FERC.

D. Factors Beyond Current Management Control

While the authors recognize the distinction between those cost efficiency elements current management can control (which we shall term "operating efficiency") and those determined primarily by the decisions of previous management in constructing the existing generation and transmission and distribution network (which we shall term "investment efficiency"), their proposed rating method does not separate these two very different concepts. This is a critical deficiency which alone would result in their proposal failing to meet its own stated goal of producing a fair and objective measure that does not ". . . penalize or reward firms arbitrarily for performance results that are beyond the company management's control." [Page 1.2.]

The importance of distinguishing between operating and investment efficiency is particularly critical in the electric utility industry because costs are determined in large measure by very long-lived capital investment decisions. It takes 8 to 14 years to plan and construct generation units that will have an operating life of 30 to 40 years. Transmission and distribution capacity generally can be added more quickly but their operating life is frequently even longer. Thus, at any point in time, the current management of an electric utility is operating facilities the vast bulk of which were designed and constructed by the firm many years before. This is especially true now that the rates of growth of electricity demand and utility construction have slowed. The nature of these facilities largely fixes the utility's capital costs and determines fuel requirements and required operation and maintenance levels.

An evaluation of past utility investments in light of current circumstances would provide a highly misleading guide to the prudence of past management and no indicator at all of the quality of current management. The present physical plant of a utility is composed of facilities that have been assembled over a period of perhaps 40 to 50 years. At the time the firm decided to make these investments, the then-future conditions under which they would be constructed and operated could not be known with certainty. Decisions as to how much and what kind of capacity to install always must be based on estimates of future trends in load growth, load shape, fuel costs, technological changes, construction costs, environmental factors, and a host of other elements, all of which interact to determine the ultimate costs and benefits. Forecasts of each of these trends are subject to substantial error and yet each trend can drastically affect the outcome.

Because of the uncertainties under which investment decisions for electric utilities must be made (i.e., load growth, load shape, fuel costs, technological changes, construction costs, environmental regulations, cost of money, decisions of state regulatory commissions and the FERC), it is most difficult after the fact to determine whether they were prudent and efficient decisions. It would be inaccurate to presume management error because capacity was added to meet an estimated load growth of 5 percent when the actual growth was only 4 percent, as long as the planning estimate of 5 percent represented the best forecast that could have been made with the information available at the time. Nor can management necessarily be faulted for not installing coal capacity because, after the fact, coal turned out to be the most cost-effective fuel. On the other hand, it is also true that unforeseen changes in circumstances may make poor decisions appear relatively efficient when the situation is reviewed after the fact. In each case, the relevant question is: Were the original investment plans based on the best predictions that could have been made at the time? In no case can current management be evaluated fairly based on the stock of capital it inherited nor can past management be judged solely by the ultimate results of its decisions. Good decisions can neither transform history nor will they always be proved right after the fact. Comparisons of average revenue levels or changes are, in large part, measures of how decisions, long past, turned out at subsequently determined levels of factor cost and demand.

Assessing the efficiency of investment decisions is further complicated because the period required for evaluation is necessarily long. The efficient decisionmaker selects the investments which maximize the present discounted value of the excess of benefits over costs over the life of the investment. Thus, it is life cycle costs which are relevant in assessing investment efficiency. Given this, the capital and operating costs incurred in a single year, or over a short period of years, could not be used fairly to evaluate the relative merits of alternative investment decisions even if there were no uncertainties about the future or if the original decisions reflected accurate forecasts of future events.

From the foregoing discussion we conclude that:

1. Investment efficiency must be viewed separately from operating efficiency.

2. Current management cannot be judged by any measure which does not take as given the capital stock it inherited.

3. The prudence of past investment decisions must be evaluated in light of the information available to management when those decisions were made.

4. Life cycle costs, reduced to present value, are the only appropriate way to evaluate investment decisions.

Since the proposed methodology meets none of these standards it is, in our view, fatally flawed.

III. RANDOM VARIATIONS BEYOND MANAGEMENT CONTROL

A. Introduction

The previous section outlined some of the more important reasons why classification of utilities into comparison groups based on exogenous factors cannot be done adequately. It also indicated the flaws in not recognizing in an efficiency measure the distinction between operating and investment efficiency. While it is doubtful that these critical deficiencies in the proposed methodology could be remedied, even if they were, there would remain a substantial degree of randomness in measured efficiency which would defeat the attempt to reward management fairly for its contributions to efficiency.

If we assume that all firms within a comparison group are comparable in that they have access to the same technologies, the same inputs and input prices (e.g., fuels, labor, transportation), provide the capacity and energy to meet the same load patterns, serve virtually identical service areas under identical regulatory treatment, and are in long-run equilibrum (i.e., they have completely adjusted to these factors), a comparison of their average revenues would produce a valid index of their relative efficiency. As outlined in the previous section, the fact that none of this is true dooms the static measure of efficiency suggested by the report. The dynamic measure (changes in average revenue from the average of prior years) is similarly flawed in that it will respond as readily to changes exogenous to management as to those management can control. These exogenous changes may occur in the markets in which the utility buys and sells, in the nature of regulation, or in the specific events that affect the utility itself.

B. External Changes in Input and Output Markets

Changes in the availability and prices of inputs such as fuel and equipment obviously have the potential to change the level of utility costs and hence of average revenue. Since to a large extent utilities are price takers in input markets and most input requirements are largely fixed in the short-term by past investment decisions, these changes in costs cannot be avoided. This would pose no particular difficulty if they affected all utilities equally. However, both changes in price and availability of inputs and the importance of those changes to the costs of individual utilities vary over a wide range. The result is relative changes in average revenues which may bear no relationship to the efficiency of management decisions.

The following series of examples illustrates instances in which relative changes in average revenues would be distorted by exogenous changes in input markets:

1. Changes in relative fuel prices will increase the costs of utilities having generators requiring increasing cost fuels and reduce the costs of those utilities using fuels which are falling in relative price. The frequent, significant and generally unexpected changes in the relative costs of oil, coal, natural gas, and nuclear fuels in recent years would have created differences in measured dynamic efficiency quite unrelated to the effectiveness of utility managers.

2. Changes in the costs of transportation and in the relative costs of alternative modes of transportation change substantially the delivered fuel costs of utilities independently of changes in their f.o.b. prices. Those utilities dependent on rail transportation have been hard hit by rail deregulation. Those moving fuels by truck have been seriously affected by changing prices of gasoline and diesel fuels, free entry into trucking and other aspects of deregulation.

3. Changes in the demand and supply conditions for the sale of economy power between utilities also can affect relative costs dramatically. The availability of electricity to California utilities from the Bonneville Power Administration or to Pennsylvania utilities from Ontario Hydro, American Electric Power or other coal- or hydro-based utilities frequently may determine the relative changes in observed average revenues.

4. Changes in the availability of transmission capacity from other utilities will affect the extent to which economy and diversity exchanges are possible for some utilities. These transactions frequently may have substantial effects on relative costs.

5. The changes in the market for various types of labor often are different among areas and can result in differing regional patterns of wage settlements or in the costs of outside construction labor. These may affect utility labor costs or the availability of specific types of skilled labor.

6. The energy input used to produce hydroelectric power is falling water, the availability of which (and its relative importance to utilities) varies widely among regions of the country and with year-to-year climatic conditions.

These examples of exogenous changes in input markets (and the list could be extended substantially) illustrate the bias inherent in using changes in average revenues as the basis for measuring dynamic efficiency. Similar bias may occur from changes in the output markets of electric utilities (e.g., changes in the demands for electricity registered by their customers).

The amount of power and energy demanded by an electric utility's customers will vary from year to year. While sales vary, the fixed costs associated with supplying electrical service do not; hence variations in sales will affect costs per unit and thus average revenue. In addition, variation in the level or rates of growth of sales to customers under different tariffs will directly affect the level of average revenue without any regulatory action. The following examples serve to illustrate this point:

1. An extended period of recession, such as the present time, will differentially affect the level of average revenue of utilities through:

a. Reduction in the level of kilowatt-hour sales to industries specifically affected;

b. Reduction in the growth rate of kilowatt-hour sales to other industries and to residential and commercial customers;

c. Changes in the availability and terms of economy sale and purchase arrangements among utilities (e.g., those where service areas are particularly hard hit will be willing to sell more at lower prices); and

d. Resulting reduction in the need for fuels will affect their prices and resulting fuel adjustments.

2. Periods of rapid economic recovery will tend to have the opposite effects. Average revenue will fall with increased sales to large industrial customers and costs per unit will decline with increased sales. Economy power would be less available or sold only at higher prices. Fuel markets should respond with higher prices and/or more restricted fuel availability.

3. Even absent general shifts in national economic conditions, regional variations in growth rates and patterns of demand will cause variations in average revenues and unit costs. Structural shifts, such as a long-term decline in the steel and auto industries, affect relative load patterns over extended periods.

4. Small utilities, and those whose major loads are concentrated in a few industries, will be especially susceptible to variations in unit costs and average revenue levels beyond their control.

5. Shifts of wholesale customers either from or to alternative suppliers or self-generation will cause uncontrollable changes in the level of unit costs and average revenues.

C. External Changes in Regulation

Another important determinant of year-to-year changes in average revenue over which utility management can exercise little control is change in regulatory treatment. Changes in the timing of rate cases, accounting treatment of various expense categories, changes in the allocation of cost responsibility among customer classes and the allowed levels of rate base and rate of return can, and do, significantly affect the relative average revenues of utilities over time. The following are some examples of these changes and the effect they may have on cross-sectional comparisons of the average revenues of electric utilities.

1. Reduction of regulatory lag, which is generally viewed as desirable, may create the illusion of poorer performance among utilities in the affected states in the short run. Over a longer period such a reduction would improve the measured performance of utilities as their costs of capital were reduced.

2. The presence or absence of fuel cost adjustment clauses will cause differences among the observed average revenues of utilities even though they are subject to exactly the same increase (or decrease) in underlying costs.

3. The switch to flow through from normalization of tax benefits reduces average revenues for subject utilities in the short-term.

4. The method used to depreciate additions to utility assets can have a major effect on the time pattern of rate increases and hence on the resulting pattern of average revenues. The depreciation treatment chosen by regulators is to a large extent external to management control yet may have profound effects on performance as measured by average revenues. Rapid depreciation, for example, would create the illusion of poorer performance in early years and the opposite illusion in subsequent periods.

5. Lifeline rates and similar attempts to place greater relative burdens on commercial and industrial customers will heighten the sensitivity of average revenue to economic fluctuations.

6. Differences among commissions in rate design (e.g., time-of-day or marginal-cost-based rates) will directly affect short-term average revenues as well as affect the costs of the utility and hence its longer term average revenue requirements.

7. Differing methods used by states in defining avoided costs in meeting the requirements of the Public Utility Regulatory Policies Act (16 U.S.C. §824) will produce differences in utility costs and thereby average revenues.

8. Variations among states on the inclusion of construction work in progress in the rate base will produce variation in both the level of rates at a point in time and their pattern of growth over time.

Since these, and other, regulatory policies are largely beyond management control, and yet can greatly alter measured performance under an average revenue standard, there will be a large random component to performance ratings with the resultant diminished relationship between the efficiency of management performance and the rewards offered under the proposed system.

The factors cited in this section illustrate the difficulty of establishing a relationship over time between management effectiveness in cost control and an efficiency measure which merely examines relative average revenues. Clearly, some method would have to be found to isolate and allow for such exogenous influences if the incentive regulation mechanism is to have the qualities desired by the authors. In its present form, the report does not do an adequate job of recognizing or coming to grips with this problem.

IV. BIAS INHERENT IN AN AVERAGE REVENUE COMPARISON STANDARD

A. Introduction

Incentive regulation schemes, and especially those that focus substantial financial benefits on managers, must be examined for the extent to which they provide an incentive for firms or their managers to "game" the system. That is, management may be given an incentive to ignore the underlying economic costs and benefits of alternative decisions. Managers should not be provided rewards for actions which enhance a current measure of their performance but will result in higher costs to ratepayers over the longer term. A system of monetary efficiency awards to management assumes that at least some managers respond to monetary incentives. Given this assumption, we must be especially careful that incentives are created only for behavior consistent with the long-run public interest. These comments do not critique the business philosophy or views on ethics of the particular individuals who are managing the nation's electric utilities at any given time. However, they must address whether a proposed system invites abuses or rewards seemingly innocent but unwise decisions and practices.

The authors of this report recognize the potential harm of improper incentives and have attempted to design their proposed system to avoid some of the more obvious biases. They reject performance measures which concentrate on a single aspect of the utilities' operations (such as heat rate) so that managers will not have an incentive to incur greater expenses in other areas (such as maintenance or fuel costs) to achieve savings in those areas subject to the incentive mechanisms. Unfortunately, the use of an average revenue standard, while avoiding some biases, falls prey to biases of its own. Specifically, it provides an incentive to choose alternatives that will keep down current rates, even at the expense of more than offsetting rate increases later. Managers would be provided an incentive to keep down current rates by:

1. Advocating accounting treatments which minimize current revenue requirements;

2. Avoiding investments in capital-intensive, long-lived projects with their attendant high revenue requirements in early years;

3. Timing rate increase requests and the in-service dates of new facilities to manipulate average revenue ratings;

4. Changing the nature of services provided to reduce revenues per kilowatt-hour; and

5. Structuring rates to promote low-cost services.

B. Affecting Average Revenue Through Accounting Changes

One of the consequences of using average revenue as the basis of performance comparisons to reward "successful" managers is changing the relative desirability of postponing the recognition of costs in rates. If it is assumed that financial incentives are a primary motivating force for managers' decisions, an assumption implicit in the authors' approach, their method may result in biased decisions. Since the senior managers, who would share most heavily in incentive awards, are likely to be senior in age as well as position, an incentive to improve measured performance in the near term would be created. (Additionally, this incentive could result from relatively high discount rates which even younger managers may apply to future incomes. High discount rates can result from executive mobility among firms, uncertainty as to the longevity of the incentive program or a tendency for the consumer discount rate to exceed that of the corporation.)

Among the accounting treatments which shape the time distribution of electric rates are those related to:

1. Treatment of deferred taxes;

2. Speed and method of adjusting rates to the costs of major capital projects;

3. Treatment of prospective nuclear decommissioning costs;

4. Treatment of construction work in progress; and

5. Deferral of fuel expenses.

In each of these areas, a system of monetary awards for present managers tied closely to current rate levels would create an incentive for them to take positions on these issues which may be contrary to the best interests of their stockholders and/or ratepayers.[7]

Whether the benefits of accelerated depreciation or investment tax credits should be flowed through directly to ratepayers or normalized over a period of years is an area of both past and present controversy. In general, it is fair to say that utilities have argued against quickly flowing through tax benefits. The incentive given to utility managers to accept, or even to request, flow through accounting of tax benefits in ratemaking would be greater under the proposed plan without any change in the underlying economic costs and benefits to the firm or its ratepayers.

The treatment of very large, and infrequent capital additions (such as large base load generation stations) in rate base also offers the possibility of

---

[7] The authors suggest that their incentive proposal would create a conflict between utility managers' responsibility to seek an adequate rate of return for shareholders and their desire to keep rates down to earn bonus payments. They advocate and rely upon generic rate of return proceedings to eliminate this conflict. In view of recent changes in FERC Staff positions, this reliance may be misplaced.

altering the time stream of rates. The incentive to phase large new facilities gradually into rate base would appear to be substantially greater under the methodology proposed by the authors. [8]

For similar reasons, executives would be given a financial incentive to defer the recognition of expenses associated with nuclear decommissioning or fuel cost escalation. Of these, nuclear decommissioning costs are generally the most susceptible to relatively substantial shifts of cost recognition between periods. However, the presence in some forums of fuel cost balancing mechanisms (which keep fuel costs reflected in rates relatively constant at forecast levels with subsequent adjustments to make up for surpluses or deficiencies) can shift year-to-year relative average revenues by significant amounts. In both cases, the utility managers would be given an incentive to adjust fuel cost or nuclear decommissioning estimates or the treatment sought for them in rates to reduce present levels or current changes in average revenues to maximize the present value of expected bonus payments.

C. Bias Against Capital-Intensive Investments

Just as management would be given an incentive to seek accounting methods which minimize current revenue requirements, so they would have potentially greater incentives to alter the composition of capital to achieve the same purpose. They would increase their potential bonus payments by minimizing investment in long-lived, capital-intensive projects for which the greatest

---

[8] A counterargument also can be made. If even staged, the addition of a nuclear plant to rate base will raise average revenue relative to the comparison group enough to greatly reduce the probability of a management bonus based on static rates, the managers may maximize the value of expected bonus payments by bringing the plant quickly and completely into rate base (and rates) and subsequently enjoying high relative dynamic efficiency as depreciation reduces rate base and load growth absorbs the added capacity.

benefits occur in the later years of operation. A management as motivated by financial incentives as the authors assume may maximize the prospect of bonus payments over the relatively short-term by biasing capital decisions toward smaller investments that minimize the present effect on rates.

The best way to illustrate the kind of choice managers face in making major capital decisions, and the incentives which the proposed plan would bring to these decisions, is through a simple example. Suppose that load growth requires the addition of 1,000 megawatts of generation capacity over the next ten years and management has the option of meeting this through the addition of a 1,000 megawatt unit, which also will produce significant fuel cost savings, or a series of 10 100-megawatt units added one at a time. The alternatives may appear as in Table II below. The net costs of the large efficient plant are greater in the initial five years. Thereafter, its net costs become clearly, and increasingly, lower than the small-scale alternative. A management concerned with bonus payments over the near term clearly would opt for the small-scale strategy even though the present value of its net costs is higher.

TABLE II

Year	Alternative A [1] — Addition of Single Large Fuel Efficient Plant: Rate Base (1)	Carrying Cost (at 20%) (2)	Fuel Savings (3)	Carrying Cost Net of Fuel Savings (4) (2)-(3)	Alternative B [2] — Addition of Small Unit Each Year with No Fuel Savings: Rate Base (5)	Carrying Cost (at 20%) (6)	Fuel Savings (7)	Carrying Cost Net of Fuel Savings (8) (6)-(7)
1	$1,000	$200	$75	$125	$100	$ 20	$0	$ 20
2	967	193	75	118	197	39	0	39
3	933	187	75	112	290	58	0	58
4	900	180	75	105	380	76	0	76
5	867	173	75	98	467	93	0	93
6	833	167	75	92	550	110	0	110
7	800	160	75	85	630	126	0	126
8	767	153	75	78	707	141	0	141
9	733	147	75	72	780	156	0	156
10	700	140	75	65	850	170	0	170

Alternative A:

5 - Year Present Value of Increased Net Costs @ 10%: $428
30 - Year Present Value of Increased Net Costs @ 10%: $665

Alternative B:

5 - Year Present Value of Increased Net Costs @ 10%: $204
30 - Year Present Value of Increased Net Costs @ 10%: $922

[1] Assumes single first year investment of $1,000 depreciated on a straight line basis over thirty years and an annual fuel savings of $75.

[2] Assumes ten annual investments of $100 depreciated on a straightline basis over thirty years with no fuel savings at all. It is assumed that nonfuel operating, maintanence and repair costs are indentical to those of Alternative A.

V. EFFECT OF RANKINGS ON REGULATORY TREATMENT

The authors of the report express concern that performance evaluation not lead to increased risks to utilities which would adversely affect their costs of capital and thereby the rates charged their customers. To avoid this, they focus the effects of their suggested performance comparisons on bonuses to the managers of the utilities rather than on rewards and penalties directly to the stockholders. While this approach reduces the direct effect of the incentive program on the risk of holding utility securities it does not consider the possible, and in our view probable, indirect consequences of performance rankings on the regulatory treatment of electric utilities.

Regulators are unlikely to treat equally utilities with high and low performance rankings especially if, as the authors hope, the regulators are directly involved in the performance incentive program. This is true for at least two reasons. First, most state commissions are required to establish rates that provide for recovery of the costs of capital or other expenses which are prudently incurred in the public interest. If the performance rating system was successful in identifying managements that, given the exogenous influences they faced, were unsuccessful in keeping costs at least close to average levels, the regulators may feel obligated to disallow "excess" expenses or rate base as imprudent.[9] Secondly, in many states, if not most, regulation is an element of the political process. An elected commission, or one responsible to an elected governor or legislature, may find it hard to ignore rankings produced by a federal (or cooperative state/federal) agency in acting on rate increase requests.

---

[9] Of course if, as is more likely, the rating system failed to distinguish between good and poor management performance it would be of no value for any purpose.

Granting a large rate increase to a utility ranked at the bottom of its comparison group would in many circumstances require no small amount of political courage.

There are many areas in which regulators are required to exercise a great deal of judgment in ratemaking. Deciding what items should be included in rate base, what incurred costs were prudent and what is a fair return on equity frequently are not straightforward decisions. Any ranking of utilities by their estimated levels of performance is quite likely to bias such decisions in favor of highly ranked utilities and against those rated as poor. This likely feedback from performance ratings to rate treatment would increase the risk of utilities' securities and thereby their cost of capital. This unintended effect of the incentive regulation scheme will tend to offset any benefits which flow from increasing the efforts of utility managers to operate more efficiently.

VI. EFFECT ON COOPERATION AMONG UTILITIES

One of the most important sources of efficiency and technological progress in the electric utility industry is cooperation and information sharing among utilities. A system designed to create direct competition among the managers of utilities runs a substantial risk of weakening this important and proven engine of progress.

At the present time, utility managements are generally quite willing to share their ideas with each other as well as enter into transactions which may confer disproportionate benefits on other utilities. The engineering drawings of plants and transmission or distribution systems frequently are made available to "rival" utilities along with recent performance data. Techniques of lowering maintenance expenses and increasing fuel efficiency are discussed freely. Joint research is sponsored through the Electric Power Research Institute into a number of promising technological and policy innovations. If utility managers are motivated by monetary rewards, as the authors hypothesize, and are forced to compete with other utilities in their comparison groups, they would have a greater incentive to concentrate research and development within the firm and to rely on some combination of trade secrets and patent protection to keep the advantages of progress for their own utilities. This would be contrary to the intentions of the authors and potentially destructive of one of the finest systems of technological diffusion among domestic industries.

Other joint and cooperative activities among utilities also could suffer to the extent that the program created a competitive rather than cooperative relationship among utilities. The benefits of power pooling are substantial and widely recognized. The smaller members of pools frequently derive benefits from pool activities disproportionate to their contribution to the savings of larger pool members. An incentive system designed to reward managers on the basis of relative costs is inconsistent with promoting such activity. It also may be inconsistent with promoting other forms of mutual assistance in which the benefits are not always equal among the participating firms. These could include (1) emergency support, (2) economy sales, (3) shared research on load management and metering, (4) joint unit participation, and (5) provision of transmission services. It is doubtful that the authors of this report intend their program to provide negative incentives to these forms of useful and cost-saving cooperation among utilities. The proposed relative average revenue standard, however, appears to have precisely that effect.

VII. OTHER POTENTIAL DIFFICULTIES WITH THE PROPOSED STANDARD

The authors assume that the proposed methodology can be used to reward management promptly for its relative performance during the past year. However, this seems infeasible. Since the required calculations would be based on Form 1 data, they could not be started until those forms were available. The Form 1 must be filed annually with the FERC by April 30th, unless an extension is granted; the data generally become available on computer tape sometime between November and January of the following year. Thus, the coded data for 1983 performance evaluations may not be ready for processing until the beginning of 1985. It would be surprising if the rankings and suggested rewards would be available before the middle of 1985. If, as we have suggested above, it is necessary to go beyond Form 1 data to produce reasonable groups or rankings, the lag could be substantially longer. The length of this lag could reduce significantly the incentive effect of prospective performance bonuses on the behavior of utility executives.

Another troublesome feature of this, and most other, statistical performance rating schemes is that the ratings of utilities will vary substantially with relatively minor changes in the methodology employed. The groups of utilities selected through the recommended statistical procedures will differ depending on both the period used for classification and the exact formulation of the methodology employed. The addition of a large nuclear plant, for example, will alter rankings based on generating capacity. For many utilities, the addition or loss of a few large industrial customers can alter greatly the growth rate of kilowatt-hour sales and the percentage of sales made to commercial and industrial customers. Principal components analysis, used as part of the grouping procedure, can be conducted with the exogenous variables having equal weight (as we have done in the example above) or with specific weights assigned to each. Since the range of weights that could be used is considerable, many different groupings could be produced by the procedure from the same underlying data.

Just as the groups of utilities compared can be changed with slight changes in methodology, so too can the average revenue measure. Changing the classification of sales included in the calculation (e.g., excluding partial requirements wholesale sales) may alter the resulting rankings. Changing the number of years over which the average revenue is calculated or the weights assigned to each will change the results, and sometimes by a substantial amount. In short, the choice of methodology used to create the groupings and calculate the performance measure can have as much influence on the result as the underlying management performance.

Two key assumptions underlying the proposal require the voluntary cooperation of parties with diverse interests. The authors of the report recognize that the success of their recommendations depend, to a large extent, on the assumption that state commissions will adopt and/or cooperate with the incentive program and that utilities will willingly participate in it. State and federal commissions frequently are not of one mind regarding regulatory issues. It seems unlikely, absent federal compulsion, that they would all adopt similar programs and even less likely that they would adopt identical programs. The effect of a mixture of federal and state programs on the incentives of utilities subject to multiple jurisdictions for substantial parts of their business is speculative. The programs could complement or offset each other. The effects of a federal program would almost certainly be weakened by the failure of states to cooperate.

The assumption that utilities would voluntarily opt to join the incentive program is likewise questionable. To join may be viewed as recognizing the validity of average revenue rankings which, if unfavorable, would surely be matters at issue in state rate proceedings. The authors, apparently recognizing the probability that some firms would not elect to join the program, suggest that commissions could choose to adjust allowed rates of return to reflect nonparticipation. This would, of course, make the "voluntary" incentive program essentially mandatory.

While the study gives lip service to quality of service and suggests some possible guidelines it does not give nearly enough attention to this area. Variations in average revenue frequently can result from variations in the type and quality of service provided. Average revenue, all else equal, will vary with:

1. Whether or not large customers are required, or induced by rates, to own their own transformation equipment;

2. Whether shopping centers and apartment complexes are master-metered or individually metered;

3. The reserve margin maintained by the utility;

4. The size of crews and stock of parts and equipment available to repair equipment failures and restore service after storm outages;

5. Expenditures on maintenance programs; and

6. Line extension policies.

These are all areas in which a delicate balance between costs and benefits requires the recognition of service type and quality as well as price. The proposed methodology is not designed to recognize or deal with these and other required trade-offs.

Another possible consequence of the proposed program is a significant increase in regulatory costs. These costs would result from increased staff positions needed to administer the program and adjudicate disputes. Increased costs also would result from increased reporting which may be required of utilities as regulators attempt to improve the scheme of classifying utilities or quantify additional exogenous factors or the "quality" of output. The exact dimensions of this increase would, of course, be dependent on the final form of the program adopted.

VIII. ADVANTAGES OF THE PLAN AND CONCLUSIONS

Since the authors of the report do a good job of presenting the prospective benefits of their proposal, we have emphasized its negative aspects in this commentary. On balance we believe that the negative aspects outlined above do far outweigh the potential for significant productivity gains. On the other hand, it must be recognized that the report does have its strong points. We agree with the authors that there should be a relation between the compensation of managers and the quality of their performance. We likewise agree that one-dimensional measures of performance (such as heat rates or unit availability) can provide very distorted impressions of the overall level of management performance. Moreover, we agree that an incentive program based on performance, even if distributed through a very imperfect mechanism, could have net benefits. We are convinced, however, that a formal mechanistic approach producing rankings that appear to lend statistical precision to a very imperfect process is not the proper approach. The reasoned judgment of knowledgeable individuals familiar with the details of a specific utility's operations and markets is far more likely to identify outstanding performance than is the formalistic approach advocated in this report.

We conclude that the principal method recommended in the report is fatally flawed in a number of respects: (1) its methodology cannot produce groups of utilities that can be compared fairly; (2) its suggested performance measure cannot fairly compare relative management performance; (3) its use invites significant biases in management decisions; and (4) regulators are likely to seize on it for uses unintended by the authors and contrary to their objectives. We urge the FERC Staff and others interested in pursuing efficiency incentives to use the valuable parts of this report to attempt to frame more sensitive and less formalistic ways to recognize and reward outstanding performance by utility management.

IX. OTHER INCENTIVE PROPOSALS

A. Introduction

In addition to their primary advocacy of an efficiency incentive mechanism based on average revenue, the authors of the report recommend one potentially ancillary procedure to reward efficiency in construction cost control and suggest a method of indexing rates to externally determined input costs as a possible alternative to their principal recommendation. Since these proposals are not advocated as strongly as the average revenue measure, our comments are presented in outline form without the detailed discussion we have devoted to their principal recommendation.

B. Proposed Construction Cost Incentive System

The basic idea of the construction cost incentive system presented in the report is quite simple: reward companies and managements who bring major construction projects to fruition within their estimated costs. In theory, all that is required is a comparison of the completed cost of the project (adjusted for inflation) with its estimated costs. A lower rate of return would be applied to project costs in excess of the estimate. A higher rate of return would be allowed on projects whose completed costs fell short of the estimate. Utility construction managers who were successful at bringing in projects within budget also would be awarded bonuses. The advantages of the program are alleged to be more realistic construction cos'. estimates and increased motivation of utility managers to avoid cost overruns.

The objectives of the proposed program are certainly laudable and the theory of its operation is simple. There are, however, numerous practical problems with implementation, some of which are ignored while others are recognized but their solution is assumed. These difficulties are much more substantial than the authors recognize and would, in our judgment, result in a program burdensome to administer with no significant likelihood of any net benefit and a strong likelihood of substantial bias in management decisions. We discuss a few of the most glaring of these difficulties below.

The first difficulty is that the risks in major projects tend to be asymmetrical. With any given cost estimate, there is a much greater probability that the final cost will be double the estimate than one-half the estimate. Thus, even with an unbiased estimate of the costs, the application of a symmetrical incentive rate of return scheme will increase greatly the riskiness of the regulated enterprise, because it will create a possibility of a very large downside potential and no correspondingly large upside potential. Unlike the unregulated enterprise, the regulated firm will pass any operating savings directly to its ratepayers. A nuclear plant may, if oil prices escalate very sharply, result in truly huge cost savings--savings so great that the net cost of a nuclear plant might ultimately turn out to be negative. While regulation contemplates flowing all of these benefits through to consumers, under the proposal much of the corresponding risk of cost overruns would be borne by the utility and its managers. It is <u>that</u> which contributes to an asymmetry of risk that could scare away investors.

The effect of the asymmetry of risk will be to reduce incentives to undertake projects with substantial risks of cost overruns even where the net expected benefits are clearly positive. Suppose that utility management sees that if it can cut the cost of construction by 20 percent, the best it could hope for, it can earn 16 percent instead of 15 percent. But if costs double, which is not out of the question, it will earn 10 percent instead of 15 percent. Management might be understandably reluctant to risk the health of the company just for the sake of a relatively small gain, even if the probability of a gain is greater than the probability of a loss. Utilities are less likely to build under these circumstances and as a result, consumers may be deprived of the possibility of major cost savings. Thus, an incentive rate of return scheme must either provide for a cap on the loss to the utility, or must be based on a complete cost-benefit analysis in which the utility is able to share in the benefits as well as in the costs.

The asymmetry of rewards and benefits also will create a bias against new and innovative technologies. These projects are more likely to produce cost overruns even if well managed. The greater the novelty in the character of the project the more likely it is that cost overruns will necessarily result from lack of knowledge about the new field rather than from poor project management or biased estimation. Additionally, innovative energy projects frequently contain a significant research component. Applying what is in effect an asymmetrical reward and punishment scheme, will unduly discourage the undertaking of such projects, and lose the benefits to be gained from future projects that follow the one in question. It is difficult to conceive how a regulatory commission could compensate for this bias by establishing a higher base rate of return. It would be difficult enough to determine an appropriate risk premium but even then the basic asymmetry of benefits and costs would remain.

A second difficulty with the analysis is the implicit assumption that managers of regulated utilities really want to build these big new projects. From this assumption it follows that they may try to persuade the regulatory agency to let them build the project by making construction cost estimates which are biased on the low side. At the present time it is at least equally plausible that the regulated company, whose stock is selling below book value, does not really want to build large new plants. If utilities' managements will build such plants only if given the prospect of major financial reward, they may, if they are as unmotivated by public interest considerations as the authors apparently presume, submit construction cost estimates which are strongly biased upwards. The regulatory commission, of course, could refuse to approve the construction of those projects because they are too expensive. In that case, the utilities may very well have discharged their legal obligation to serve. If, on the other hand, the regulatory agency accepts the proposed projects, and if it provides for extra return if the costs come in under the estimate, the utilities may stand to enjoy very considerable gains. Theoretically the regulatory agency could criticize the utility's cost estimate for being biased upward, that is, for being a higher cost estimate than engineering evidence could justify. But it is difficult to see how the regulator could reject a cost estimate that had a contingency allowance which constituted 90 percent of the total estimated cost, since there have been a considerable number of projects in the past where, contrary to all expectations, the final cost has been 5 or 10 times the original estimate. The commission certainly has no way to assess the realism of such adjustments to conventional engineering cost estimates.

If utilities were as motivated by financial rewards as the authors assume, they might attempt to "game" the system to extract greater profits. It would be possible for a utility to estimate the total net benefits that would be generated by a proposed project, and use that estimate to build up cost estimates. This could allow the utility to end up with a substantial portion of the economic rents in the project unless costs go thoroughly out of control and far exceed even the inflated estimate. If that sort of behavior were to develop in response to an incentive rate of return scheme, we would have shifted from cost-plus regulation to rent-appropriation regulation, with perhaps some saving in real costs but with a heavy loss to consumers.

The proposed methodology for measuring construction cost performance is exceedingly cumbersome. Essentially it involves breaking down the original project cost estimate into component parts for each three months of the construction period. Each of these component parts would be tied to an "appropriate" external index of the costs of the inputs involved. In addition to changing with inflation, the estimated cost would be changed if certain "triggering events" required a change in the scope of the project (e.g., change in design required by regulation). The estimated cost, adjusted for inflation and changes in scope, then would be compared with the actual cost. A base rate of return for the project, set high enough to compensate for project-specific risks and the risk associated with the incentive program, would be allowed if the project is completed at the estimated cost. A penalty rate of return, set below the government bond rate, would apply to the proportion of costs in excess of the estimate. A return above the base level would apply to the proportion of the plant costs which fell short of the estimated level.

For this methodology to work fairly it must be assumed that the regulators will:

1. Monitor the initial estimation process to be certain that the utility does not "game" the system by inflating the original estimate;

2. Be able to construct exogenous price indexes applicable to each portion of what are frequently one of a kind construction projects occurring at specific locations;

3. Specify in advance the events which might trigger a "change in scope" and be able to estimate correctly the change in the original estimate that would be appropriate for each such event;

4. Correctly identify project-specific risks and the risks attendant to the incentive mechanism for the specific project to set the base level of return;

5. Overcome the basic asymmetry of costs and benefits discussed above and correctly set a penalty return which will provide neither too great a risk to security holders nor too little incentive for management;

6. Insure that the formula will be consistently applied over time and that future regulators will not make compensating adjustments in rate base or rate of return to offset the incentive feature; and

7. Insure that utilities do not achieve their construction performance goals by shortchanging construction standards at the expense of higher outage, maintenance, and repair costs over subsequent years.

The uniqueness of most utility construction projects, both in plant design and location, the difficulty of assessing the risk of new plant sizes or technologies, the range of construction difficulties that can and do occur, the impossibility of commissions binding their own future decisions, and the asymmetry of costs and benefits make it highly unlikely that this program could work smoothly or fairly. Just as was the case with the average revenue standard, the movement to a formalistic approach in this highly complex industry is likely to produce counterproductive results. Management would be given the incentive to respond with inflated estimates of costs, an aversion to innovative projects and, perhaps, with cost-saving construction short cuts which will increase long-run project costs.

This is not to argue that regulators should ignore construction costs. Through the construction permit process, most states already exercise control over which major utility projects will be built. Management is already called on to account for cost overruns. Perhaps in some jurisdictions more attention needs to be paid to this process and some funds should be provided for bonuses to recognize construction managers whose projects perform well. Commissions can and do make judgments concerning the effectiveness of utilities in planning and constructing capacity additions. There is no apparent basis for the belief of the authors that implementing a formula will substitute for developing the requisite understanding of construction projects and their management required for knowledgeable evaluation and regulatory control.

C. Proposed Method of Rate Indexing

The authors' suggested alternative to their average revenue ranking proposal is to provide for longer periods of regulatory lag to give management an incentive to cut costs and thereby directly increase their firms' profits. They would achieve this by requiring that three to five years elapse between rate cases. The potentially adverse effects of postponing the opportunity for regulatory rate relief would be mitigated by allowing utilities to automatically raise rates proportionately to reflect changes in external indices of the costs of their variable inputs (the authors suggest fuel, labor, purchased power, and "other materials and supplies"). The authors find no acceptable method available to index capital-related costs. In an industry so capital intensive, this is a substantial limitation.

The authors recognize that changes in customer demands can result in substantial differences between actual and projected collections of capital costs. If demand falls, the portion of the rate designed to collect fixed costs collects less than the intended level of revenues. To mitigate this, the authors would allow regulators to change rates to reflect changes in customer demand so that the utility did not under- or over-collect its estimated capital costs.

The "automatic" process would not always, however, be completely automatic. Adjustments would be made in certain circumstances including adding or losing a large generation unit, a major change in capital market conditions or rolling over of existing debt at higher or lower interest costs. Whether the process also would allow adjustments for other externally caused events (such as unusual storm related expenses, transportation or fuel supplier strikes, changes in environmental standards, etc.) is unclear.

The workability of this proposal depends on whether:

1. Regulators could devise external input cost indexes which would measure fairly the costs of alternatives realistically available to the utility manager.

2. Commissions would restrain themselves from intervening if the utility were able to substantially increase profits.

3. The ratio of capital to variable input costs of utilities would be biased as a result of their different treatment (e.g., the firm's incentive to substitute capital, for which an adjustment to rates could be made, for labor or fuel which are covered by the automatic index).

4. The "adjustments" made during the period between rate cases would either be limited to the point of financially damaging the utility or expanded to become a continuous rate case.

Of the three incentive adjustment mechanisms suggested in the report, this provides the most promising avenue for study. Unfortunately the level of detail provided in the report is not sufficient to allow a detailed assessment of exactly how it would work in practice. Whether indices of costs which mirror the opportunities of a firm in the market, but exclude costs actually paid by the firm, can be constructed is a most serious concern in this method. It also concerns us that commissions may be much more prone to find a need for an "adjustment" between rate cases if a firm's profits rise substantially than if they fall. Such a policy would increase substantially the risk of holding utility securities.

LIST OF CLUSTER MEMBERS AND 1980 SELECTION DATA

CLUSTER NUMBER 1

Company	Megawatt Capacity (MW) (1)	Load Factor (2)	Historical Growth 1970-1980 (3)	Residential & Commercial Sales as a Percentage of Total Kilowatt-hour Sales (4)	Taxes Other Than Federal Income Tax as a Percentage of Net Plant (5)
		(percent)			
Alabama Power Company	7,785	53.9%	61.2%	44.8%	1.9%
Arkansas Power & Light Company	4,707	54.6	46.1	35.8	1.3
Baltimore Gas & Electric Company	5,249	49.6	44.0	51.9	2.7
Carolina Power & Light Company	8,126	56.3	71.2	42.3	2.2
Cincinnati Gas & Electric Company	3,899	52.9	51.0	50.5	2.6
Cleveland Electric Illuminating Company	5,482	62.3	29.9	47.4	3.0
Consumers Power Company	7,242	62.3	33.8	55.8	1.2
Duquesne Light Company	3,622	61.4	27.0	51.9	2.5
Illinois Power Company	3,973	52.5	69.6	44.8	2.6
Kansas City Power & Light Company	3,735	44.6	45.6	70.1	3.6
Long Island Lighting Company	3,952	49.3	34.1	46.8	4.2
Northern States Power Company (Minn.)	6,063	54.3	50.6	39.5	3.9
Ohio Edison Company	5,446	59.0	30.7	53.4	2.5
Pennsylvania Power & Light Company	6,777	57.3	51.3	61.3	2.6
Philadelphia Electric Company	8,142	51.8	21.7	40.2	2.8
Potomac Electric Power Company	5,504	45.6	36.2	65.5	3.6
Public Service Company of Indiana, Inc.	5,802	55.4	65.9	45.0	1.2
South Carolina Electric & Gas Company	3,562	54.2	52.2	54.6	2.0
Texas Electric Service Company	8,209	54.2	68.4	55.7	2.4
Union Electric Company	7,023	47.4	43.6	52.9	3.6
Wisconsin Electric Power Company	4,740	61.8	42.2	54.5	2.2

Statistics of Cluster					
Mean	5,573	54.3%	48.5%	50.7%	2.6%
Standard Deviation	1,514	5.2	14.6	8.5	0.8
Range	4,580	17.7	49.5	34.3	3.0

Cluster Membership = 21 Companies

LIST OF CLUSTER MEMBERS AND 1980 SELECTION DATA

CLUSTER NUMBER 2

Company	Megawatt Capacity (MW) (1)	Load Factor (2)	Historical Growth 1970-1980 (3)	Residential & Commercial Sales as a Percentage of Total Kilowatt-hour Sales (4)	Taxes Other Than Federal Income Tax as a Percentage of Net Plant (5)
		(percent)			
Alpena Power Company	7	53.6%	41.5%	51.9%	4.7%
Arkansas-Missouri Power Company	248	47.3	19.5	42.0	2.7
Central Illinois Light Company	1,533	51.9	69.3	49.8	2.8
Central Illinois Public Service Company	2,584	50.7	60.3	45.1	3.0
Central Maine Power Company	1,039	57.9	45.6	58.0	1.6
Central Telephone & Utilities Corp.	636	53.5	54.5	48.5	2.2
Columbus & Southern Ohio Electric Company	2,877	55.2	64.7	43.6	3.2
Connecticut Light & Power Company	2,837	58.0	37.6	63.4	3.4
Connecticut Valley Electric Company	0	50.0	26.4	46.2	5.0
Dayton Power & Light Company	2,688	56.8	49.5	57.1	2.6
El Paso Electric Company	1,124	59.3	59.1	52.5	1.9
Empire District Electric Company	546	55.7	(3.3)	50.5	3.2
Indianapolis Power & Light Company	2,697	51.9	22.2	52.6	1.8
Interstate Power Company	943	57.0	62.7	40.7	2.5
Kansas Gas & Electric Company	2,148	51.8	42.8	46.5	1.2
Louisville Gas & Electric Company	2,676	49.4	16.8	55.8	0.9
Maine Public Service Company	57	56.9	48.4	50.5	1.7
Metropolitan Edison Company	2,175	59.3	22.0	53.0	2.9
Mississippi Power Company	2,264	52.4	51.6	41.7	3.9
New York State Electric & Gas Corp.	1,741	59.5	22.9	63.3	3.2
Northern States Power Company	699	53.2	54.6	52.3	3.5
Pennsylvania Electric Company	2,826	60.7	41.4	49.6	3.1
Upper Peninsula Power Company	90	59.1	28.0	50.3	4.0
Western Massachusetts Electric Company	882	59.6	22.2	62.1	3.2

Statistics of Cluster	(1)	(2)	(3)	(4)	(5)
Mean	1,471	55.0%	40.0%	51.1%	2.8%
Standard Deviation	1,059	3.8	18.6	6.5	1.0
Range	2,877	13.4	72.5	22.8	4.0

Cluster Membership = 24 Companies

( ) negative

LIST OF CLUSTER MEMBERS AND 1980 SELECTION DATA

CLUSTER NUMBER 3

Company	Megawatt Capacity (MW) (1)	Load Factor (2)	Historical Growth 1970-1980 (3)	Residential & Commercial Sales as a Percentage of Total Kilowatt-hour Sales (4)	Taxes Other Than Federal Income Tax as a Percentage of Net Plant (5)
		(percent)			
Central Kansas Power Company	62	40.9%	42.9%	61.0%	2.5%
Gulf Power Company	1,709	49.0	66.0	61.2	2.2
Iowa Electric Light & Power Company	926	41.0	63.1	61.5	2.5
Iowa Power & Light Company	1,957	43.2	59.1	65.0	2.6
Iowa Southern Utilities Company	445	44.6	37.8	59.0	1.8
Iowa-Illinois Gas & Electric Company	1,346	48.5	58.1	52.0	2.0
Kansas Power & Light Company	2,606	43.9	57.0	60.8	2.0
Missouri Power & Light Company	112	44.6	23.1	64.9	5.0
Missouri Public Service Company	740	39.0	7.8	66.0	4.5
Nantahala Power & Light Company	99	46.3	38.7	82.2	5.6
Nevada Power Company	1,561	43.0	76.8	65.6	2.5
Northwestern Public Service Company	273	40.3	43.1	71.1	1.4
Portland General Electric Company	2,019	52.1	41.5	68.6	1.4
Savannah Electric & Power Company	657	53.4	45.1	61.9	2.1
Union Light, Heat & Power Company	0	49.7	63.8	65.7	1.4
United Gas Improvement Corp.	71	51.1	41.1	87.2	1.2
Washington Water Power Company	1,040	48.3	52.0	52.3	1.7
Statistics of Cluster					
Mean	919	45.8%	48.1%	64.9%	2.5%
Standard Deviation	819	4.4	16.8	8.9	1.3
Range	2,606	14.4	69.0	35.3	4.4

Cluster Membership = 17 Companies

LIST OF CLUSTER MEMBERS AND 1980 SELECTION DATA

CLUSTER NUMBER 4

Company	Megawatt Capacity (MW) (1)	Load Factor (2)	Historical Growth 1970-1980 (3)	Residential & Commercial Sales as a Percentage of Total Kilowatt-hour Sales (4)	Taxes Other Than Federal Income Tax as a Percentage of Net Plant (5)
		(percent)			
Alaska Electric Light & Power Company	48	42.5%	124.5%	80.7%	1.3%
Atlantic City Electric Company	1,330	51.0	56.9	76.0	4.8
Citizens Utilities Company	79	58.7	67.0	63.8	5.0
Concord Electric Company	0	55.8	58.7	60.7	5.2
CP National Corp.	22	54.8	65.4	83.0	1.3
Dallas Power & Light Company	4,237	49.2	53.5	80.5	4.6
Exeter & Hampton Electric Company	0	55.7	98.0	77.7	4.3
Florida Public Utilities Company	2	46.0	101.0	66.8	1.3
Granite State Electric Company	0	54.4	74.0	84.5	4.0
Green Mountain Power Corp.	108	52.2	55.5	67.7	4.1
Hartford Electric Light Company	1,898	54.3	32.5	74.9	4.1
Hawaii Electric Light Company	104	56.5	98.5	74.9	5.6
Home Light and Power Company	0	52.8	64.9	75.2	4.5
Missouri Utilities Company	31	40.3	91.0	70.2	3.9
New Bedford Gas & Edison Light Company	106	58.2	69.0	72.9	3.6
Old Dominion Power Company	0	43.9	141.9	62.7	3.9
Puget Sound Power & Light Company	849	46.8	95.2	73.1	2.3
St. Joseph Light & Power Company	409	42.6	53.9	68.2	3.6
Statistics of Cluster					
Mean	512	50.9%	77.8%	71.9%	3.7%
Standard Deviation	1,072	05.8	27.8	7.3	1.3
Range	4,237	18.4	9.4	23.8	4.3

Cluster Membership = 18 Companies

LIST OF CLUSTER MEMBERS AND 1980 SELECTION DATA

CLUSTER NUMBER 5

Company	Megawatt Capacity (MW) (1)	Load Factor (2)	Historical Growth 1970-1980 (3)	Residential & Commercial Sales as a Percentage of Total Kilowatt-hour Sales (4)	Taxes Other Than Federal Income Tax as a Percentage of Net Plant (5)
		(percent)			
Arizona Public Service Company	3,038	48.2%	118.1%	60.9%	2.8%
Black Hills Power & Light Company	218	61.1	83.0	52.5	2.3
Central Louisiana Electric Company	1,400	51.3	96.6	48.8	1.6
Central Power & Light Company	3,868	59.7	79.2	48.3	2.7
Cheyenne Light, Fuel and Power Company	13	63.0	69.7	67.3	2.2
Community Public Service Company	42	63.5	113.2	49.7	3.8
Conowingo Power Company	0	67.4	64.6	62.0	0.6
Delmarva Power & Light Company	2,389	53.9	77.2	49.5	1.8
Florida Power Corp.	5,599	48.6	104.5	58.3	2.9
Iowa Public Service Company	1,324	49.8	96.0	54.6	2.4
Kentucky Utilities Company	2,384	56.5	100.2	43.5	0.8
Michigan Power Company	3	60.9	68.8	45.0	1.3
Missouri Edison Company	0	54.7	95.4	42.0	3.7
Montana-Dakota Utilities Company	332	60.8	52.4	70.5	0.9
Oklahoma Gas & Electric Company	5,925	56.5	108.9	43.2	2.8
Pacific Power & Light Company	3,972	62.8	70.6	51.4	1.5
Public Service Company of Colorado	3,263	61.4	110.8	59.1	1.7
Public Service Company of Oklahoma	3,968	58.5	74.0	41.2	2.3
San Diego Gas & Electric Company	2,493	55.9	83.7	71.5	1.1
Sierra Pacific Power Company	547	64.5	103.2	70.1	0.8
Southwestern Electric Power Company	3,315	56.9	93.3	39.9	1.7
Southwestern Public Service Company	3,218	56.3	84.0	30.9	1.7
Texas Power & Light Company	7,554	51.1	115.7	50.7	1.9
Tucson Gas & Electric Company	1,755	56.6	153.1	36.0	3.7

Statistics of Cluster	(1)	(2)	(3)	(4)	(5)
Mean	2,359	57.5%	91.4%	52.0%	2.0%
Standard Deviation	2,111	5.2	22.7	11.1	0.9
Range	7,554	19.3	0.6	40.6	3.2

Cluster Membership = 24 Companies

LIST OF CLUSTER MEMBERS AND 1980 SELECTION DATA

CLUSTER NUMBER 6

Company	Megawatt Capacity (MW) (1)	Load Factor (2)	Historical Growth 1970-1980 (3)	Residential & Commercial Sales as a Percentage of Total Kilowatt-hour Sales (4)	Taxes Other Than Federal Income Tax as a Percentage of Net Plant (5)
		(percent)			
Boston Edison Company	2,759	57.1%	20.6%	61.8%	6.0%
Edison Sault Electric Company	52	66.9	17.5	42.2	5.6
Hawaiian Electric Company, Inc.	1,140	65.3	58.2	47.2	5.4
Kingsport Power Company	0	52.1	35.2	63.0	6.9
Lockhart Power Company	12	54.7	21.8	18.7	4.5
Massachusetts Electric Company	0	60.9	39.6	70.2	6.4
Mt. Carmel Public Utility Company	15	46.6	80.9	38.5	7.0
New Orleans Public Service, Inc.	1,298	60.0	(10.0)	56.8	4.6
Niagara Mohawk Power Corp.	5,418	68.7	19.0	55.0	4.7
Orange & Rockland Utilities, Inc.	1,036	56.7	50.6	34.2	5.8
Tampa Electric Company	3,033	62.0	68.8	53.4	3.9
United Illuminating Company	1,416	55.4	17.7	68.5	5.3
Statistics of Cluster					
Mean	1,348	58.9%	35.0%	50.8%	5.5%
Standard Deviation	1,663	6.4	25.8	15.3	1.0
Range	5,418	22.0	90.9	51.5	3.1

Cluster Membership = 12 Companies

( ) negative

LIST OF CLUSTER MEMBERS AND 1980 SELECTION DATA

CLUSTER NUMBER 7

Company	Megawatt Capacity (MW)	Load Factor	Historical Growth 1970-1980	Residential & Commercial Sales as a Percentage of Total Kilowatt-hour Sales	Taxes Other Than Federal Income Tax as a Percentage of Net Plant
		(percent)			
	(1)	(2)	(3)	(4)	(5)
Bangor Hyrdoelectric Company	170	68.1%	55.4%	47.1%	2.5%
Canal Electric Company	807	63.4	68.7	0.0	2.9
Central Hudson Gas & Electric Company	997	83.9	62.0	41.1	4.5
Central Vermont Public Service Corp.	82	60.0	43.0	44.8	2.7
Fitchburg Gas & Electric Company	47	60.9	38.6	35.5	3.6
Idaho Power Company	2,362	66.6	33.2	53.1	1.3
Lake Superior District Power Company	126	62.9	44.1	51.2	3.3
Madison Gas & Electric Company	634	68.0	67.8	54.2	2.2
Monongahela Power Company	2,122	76.3	68.4	34.2	3.3
Montana Power Company	1,104	78.3	66.6	37.5	1.8
Montaup Electric Company	649	70.0	37.5	0.0	1.5
New England Power Company	3,652	60.6	32.1	0.0	2.9
New Mexico Electric Service Company	188	70.8	71.0	27.9	3.3
Northern Indiana Public Service Company	3,121	66.4	52.9	21.2	1.4
Pennsylvania Power Company	940	67.7	25.2	42.5	2.4
Public Service Company of New Hampshire	1,247	62.1	52.2	39.9	1.9
Rochester Gas & Electric Corp.	1,255	77.5	27.0	46.3	4.3
Superior Water, Light & Power Company	25	62.9	84.2	20.9	2.0
Toledo Edison Company	1,835	64.4	34.6	44.0	2.1
West Penn Power Company	3,765	74.1	59.0	40.9	3.0
West Texas Utilities Company	1,089	61.8	93.1	37.1	3.4
Wisconsin Power & Light Company	1,738	67.5	79.5	43.1	2.7
Wisconsin Public Service Corp.	1,436	68.9	79.0	49.0	2.4
Statistics of Cluster					
Mean	1,278	68.0%	55.4%	35.3%	2.7%
Standard Deviation	1,112	6.4	19.5	16.4	0.9
Range	3,740	23.9	67.9	54.2	3.3

Cluster Membership = 23 Companies

LIST OF CLUSTER MEMBERS AND 1980 SELECTION DATA

FORCED CLUSTER NUMBER 8 [1]

Company	Megawatt Capacity (MW) (1)	Load Factor (2)	Historical Growth 1970-1980 (3)	Residential & Commercial Sales as a Percentage of Total Kilowatt-hour Sales (4)	Taxes Other Than Federal Income Tax as a Percentage of Net Plant (5)
		(percent)			
Appalachian Power Company	6,838	59.7%	86.6%	32.6%	2.5%
Consolidated Water Power Company	21	66.4	149.4	2.0	2.0
Gulf States Utilities Company	6,711	63.5	86.0	32.6	1.3
Indiana & Michigan Electric Company	4,106	63.2	72.7	28.1	1.1
Kentucky Power Company	1,097	59.2	184.1	33.0	0.9
Louisiana Power & Light Company	4,837	67.0	82.6	38.7	1.3
Maui Electric Company	87	58.6	183.3	67.6	3.9
Minnesota Power & Light Company	1,422	67.1	147.0	14.0	2.0
Mississippi Power & Light Company	2,789	71.0	100.4	38.6	3.7
Ohio Power Company	10,320	67.9	45.7	20.8	3.5
Otter Tail Power Company	4,780	67.9	109.4	45.0	1.8
Potomac Edison Company	2,042	77.2	111.2	34.9	2.7
Public Service Company of New Mexico	1,167	67.5	150.1	46.9	1.0
Southern Indiana Gas & Electric Company	1,038	67.0	105.1	37.8	1.6
Southwestern Electric Service Company	1	98.7	93.7	70.4	3.8
Upper Peninsula Generating Company	628	66.9	153.2	0.0	2.0
Utah Power & Light Company	3,166	64.2	165.6	33.1	1.6
Wheeling Electric Company	0	68.8	30.2	32.8	9.0
Wisconsin River Power Company	35	62.1	24.4	0.0	6.9
Statistics of Cluster					
Mean	2,462	68.0%	109.5%	32.3%	2.8%
Standard Deviation	2,902	8.7	48.2	19.3	2.1
Range	10,320	40.0	59.7	70.4	8.2

Cluster Membership = 19 Companies

[1] Clusters of fewer than ten members, as defined by the clustering program, were grouped together to form larger clusters.

LIST OF CLUSTER MEMBERS AND 1980 SELECTION DATA

FORCED CLUSTER NUMBER 9 [1]

Company	Megawatt Capacity (MW) (1)	Load Factor (2)	Historical Growth 1970-1980 (3)	Residential & Commercial Sales as a Percentage of Total Kilowatt-hour Sales (4)	Taxes Other Than Federal Income Tax as a Percentage of Net Plant (5)
		(percent)			
Alcoa Generating Corp.	582	82.3%	34.2%	0.0%	1.8%
Commonwealth Edison Company	18,343	49.9	34.1	59.1	4.2
Connecticut Yankee Atomic Power Company	600	69.9	1.0	0.0	2.2
Detroit Edison Company	10,726	58.3	16.4	48.7	2.3
Duke Power Company	11,769	57.6	48.9	44.3	2.5
Florida Power & Light Company	13,047	52.4	92.9	83.9	3.7
Georgia Power Company	12,945	53.2	45.6	44.2	2.0
Houston Lighting & Power Company	13,352	59.4	108.9	39.9	2.1
Indiana-Kentucky Electric Corp.	1,304	79.6	3.2	0.0	1.8
Ohio Valley Electric Corp.	1,086	79.0	1.2	0.0	2.9
Pacific Gas & Electric Company	11,649	53.8	37.3	70.0	1.1
Southern California Edison Company	13,921	53.3	31.8	55.8	1.7
Southern Electric Generating Company	1,032	74.5	(17.4)	0.0	1.6
Tapoco, Inc.	326	80.5	9.1	0.0	5.6
Virginia Electric & Power Company	10,684	52.8	68.1	58.0	2.1
Yadkin, Inc.	201	93.3	8.7	0.0	3.9

Statistics of Cluster	(1)	(2)	(3)	(4)	(5)
Mean	7,601	65.6%	32.7%	31.5%	2.6%
Standard Deviation	6,482	14.0	34.6	30.5	1.2
Range	18,142	43.4	26.3	83.9	4.5

Cluster Membership = 16 Companies

( ) negative

[1] Clusters of fewer than ten members, as defined by the clustering program, were grouped together to form larger clusters.

LIST OF CLUSTER MEMBERS AND 1980 SELECTION DATA

FORCED CLUSTER NUMBER 10 [1]

Company	Megawatt Capacity (MW) (1)	Load Factor (2)	Historical Growth 1970-1980 (3)	Residential & Commercial Sales as a Percentage of Total Kilowatt-hour Sales (4)	Taxes Other Than Federal Income Tax as a Percentage of Net Plant (5)
		(percent)			
Blackstone Valley Electric Company	0	54.9%	22.8%	51.9%	10.0%
Cambridge Electric Light Company	133	52.8	14.9	44.1	17.4
Commonwealth Edison Company of Indiana	614	56.4	(47.2)	0.0	3.9
Consolidated Edison Company of New York	10,599	48.1	(2.4)	82.5	9.0
Holyoke Water Power Company	169	66.6	(64.8)	0.0	6.4
Jersey Central Power & Light Company	3,145	48.7	120.5	68.6	7.5
Narragansett Electric Company	248	54.8	34.3	75.4	9.7
Newport Electric Corp.	31	60.5	13.4	71.7	8.8
Public Service Electric & Gas Company	10,078	48.2	21.0	62.4	5.9
Rockland Electric Company	0	40.4	32.7	67.9	14.5
Safe Harbor Water Power Corp.	230	31.6	(35.7)	0.0	5.4
Sherrard Power System	0	36.0	86.1	99.4	6.9
South Beloit Water, Gas & Electric Company	1	54.3	13.6	42.6	9.4
Yankee Atomic Electric Company	185	19.0	(75.7)	0.0	3.6
Statistics of Cluster					
Mean	1,817	48.0%	9.5%	47.8%	8.4%
Standard Deviation	3,702	12.5	54.9	34.5	3.8
Range	10,599	47.6	96.3	99.4	13.8

Cluster Membership = 14 Companies

() negative

[1] Clusters of fewer than ten members, as defined by the clustering program, were grouped together to form larger clusters.

Source: NERA computer printout, "Comparison of Electric Utility Clusters," January 10, 1983.

LIST OF CLUSTER MEMBERS AND OTHER 1980 DATA WHICH COULD AFFECT HOMOGENEITY

CLUSTER NUMBER 1

Company	Nuclear Capacity as a Percentage of Kilowatt Capacity	Hydroelectric Capacity as a Percentage of Kilowatt Capacity	Gas Turbine Capacity as a Percentage of Kilowatt Capacity	Structure Miles Per 1,000 Customers
		(percent)		
	(1)	(2)	(3)	(4)
Alabama Power Company	11.4%	17.3%	1.4%	9.2
Arkansas Power & Light Company	39.2	1.4	2.0	8.0
Baltimore Gas & Electric Company	34.8	0.0	14.4	0.8
Carolina Power & Light Company	30.8	2.7	7.0	6.7
Cincinnati Gas & Electric Company	0.0	0.0	14.5	2.7
Cleveland Electric Illuminating Company	9.0	6.2	1.2	1.9
Consumers Power Company	12.2	15.7	6.2	6.3
Duquesne Light Company	14.9	0.0	2.2	0.8
Illinois Power Company	0.0	0.1	5.2	4.9
Kansas City Power & Light Company	0.0	0.0	13.1	4.7
Long Island Lighting Company	0.0	0.0	30.6	1.0
Northern States Power Company (Minn.)	28.9	0.3	12.9	4.3
Ohio Edison Company	5.7	0.0	4.7	4.6
Pennsylvania Power & Light Company	0.0	2.2	7.2	1.0
Philadelphia Electric Company	18.1	9.8	23.3	0.6
Potomac Electric Power Company	0.0	0.0	11.8	0.7
Public Service Company of Indiana, Inc.	0.0	0.9	0.0	9.1
South Carolina Electric & Gas Company	0.0	21.3	4.3	8.3
Texas Electric Service Company	0.0	0.0	0.0	7.9
Union Electric Company	0.0	10.0	4.2	3.2
Wisconsin Electric Power Company	22.1	1.9	6.5	2.3

Statistics of Cluster	(1)	(2)	(3)	(4)
Data Points Evaluated	21	21	21	21
Mean	10.8%	4.3%	8.2%	4.2
Standard Deviation	13.2	6.6	7.9	3.0
Range	39.2	21.3	30.6	8.6

Cluster Membership = 21 Companies

LIST OF CLUSTER MEMBERS AND OTHER 1980 DATA WHICH COULD AFFECT HOMOGENEITY

CLUSTER NUMBER 2

Company	Nuclear Capacity as a Percentage of Kilowatt Capacity	Hydroelectric Capacity as a Percentage of Kilowatt Capacity	Gas Turbine Capacity as a Percentage of Kilowatt Capacity	Structure Miles Per 1,000 Customers
	(percent)			
	(1)	(2)	(3)	(4)
Alpena Power Company	0.0%	100.0%	0.0%	5.1
Arkansas-Missouri Power Company	0.0	0.0	86.1	18.6
Central Illinois Light Company	0.0	0.0	2.1	1.5
Central Illinois Public Service Company	0.0	0.0	0.0	14.6
Central Maine Power Company	0.0	25.6	3.4	5.9
Central Telephone & Utility Corp.	0.0	0.0	15.7	22.4
Columbus & Southern Ohio Electric Company	0.0	0.0	2.9	3.7
Connecticut Light & Power Company	29.4	19.8	6.8	1.4
Connecticut Valley Electric Company	-	-	-	0.2
Dayton Power & Light company	0.0	0.0	5.9	3.8
El Paso Electric Company	0.0	0.0	0.0	5.5
Empire District Electric Company	0.0	2.9	18.8	11.4
Indianapolis Power & Light Company	0.0	0.0	3.0	2.7
Interstate Power Company	0.0	0.0	6.3	17.5
Kansas Gas & Electric Company	0.0	0.0	0.0	9.5
Louisville Gas & Electric Company	0.0	3.0	4.4	1.8
Maine Public Service Company	0.0	4.1	0.0	12.7
Metropolitan Edison Company	42.1	0.0	13.7	3.4
Mississippi Power Company	0.0	0.0	6.3	12.9
New York State Electric & Gas Corp.	0.0	2.3	0.0	6.5
Northern States Power Company	0.0	27.1	68.6	0.0
Pennsylvania Electric Company	16.2	4.7	4.6	5.3
Upper Peninsula Power Company	0.0	15.9	53.2	12.2
Western Massachusetts Electric Company	33.8	26.1	16.3	2.1

Statistics of Cluster	(1)	(2)	(3)	(4)
Data Points Evaluated	23	23	23	24
Mean	5.3%	10.1%	13.8%	7.5
Standard Deviation	12.4	21.8	23.2	6.3
Range	42.1	100.0	86.1	22.4

Cluster Membership = 24 Companies

- not available

LIST OF CLUSTER MEMBERS AND OTHER 1988 DATA WHICH COULD AFFECT HOMOGENEITY

CLUSTER NUMBER 3

Company	Nuclear Capacity as a Percentage of Kilowatt Capacity	Hydroelectric Capacity as a Percentage of Kilowatt Capacity	Gas Turbine Capacity as a Percentage of Kilowatt Capacity	Structure Miles Per 1,000 Customers
	(percent)			
	(1)	(2)	(3)	(4)
Central Kansas Power Company	0.0%	0.0%	26.2%	44.9
Gulf Power Company	0.0	0.0	2.4	7.5
Iowa Electric Light & Power Company	45.1	0.2	20.4	15.1
Iowa Power & Light Company	0.0	0.0	14.4	6.8
Iowa Southern Utilities Company	0.0	0.0	0.0	10.4
Iowa-Illinois Gas & Electric Company	30.8	0.3	16.0	4.7
Kansas Power & Light Company	0.0	0.0	18.2	13.8
Missouri Power & Light Company	0.0	9.0	74.1	17.3
Missouri Public Service Company	0.0	0.0	4.9	10.1
Nantahala Power and Light Company	0.0	100.0	0.0	6.0
Nevada Power Company	0.0	0.0	26.8	5.2
Northwestern Public Service Company	0.0	0.0	12.8	23.7
Portland General Electric Company	40.7	26.5	0.0	2.8
Savannah Electric & Power Company	0.0	0.0	10.0	0.8
Union Light, Heat & Power Company	-	-	-	1.0
United Gas Improvement Corp.	0.0	0.0	0.0	2.0
Washington Water Power Company	0.0	71.6	9.3	9.7
Statistics of Cluster				
Data Points Evaluated	16	16	16	17
Mean	7.3%	13.0%	14.7%	10.7
Standard Deviation	15.9	29.7	18.3	10.8
Range	45.1	100.0	74.1	44.1

Cluster Membership = 17 Companies

\- not available

LIST OF CLUSTER MEMBERS AND OTHER 1980 DATA WHICH COULD AFFECT HOMOGENEITY

CLUSTER NUMBER 4

Company	Nuclear Capacity as a Percentage of Kilowatt Capacity	Hydroelectric Capacity as a Percentage of Kilowatt Capacity	Gas Turbine Capacity as a Percentage of Kilowatt Capacity	Structure Miles Per 1,000 Customers
	(percent)			
	(1)	(2)	(3)	(4)
Alaska Electric Light & Power Company	0.0%	23.0%	37.7%	5.6
Atlantic City Electric Company	19.5	0.0	11.8	3.6
Citizens Utilities Company	0.0	8.8	50.2	7.1
Concord Electric Company	-	-	-	2.0
CP National Corp.	0.0	17.1	0.0	18.0
Dallas Power & Light Company	0.0	0.0	0.0	1.7
Exeter & Hampton Electric Company	-	-	-	2.8
Florida Public Utilities Company	0.0	7.7	0.0	0.7
Granite State Electric Company	-	-	-	0.0
Green Mountain Power Corp.	0.0	25.3	60.7	4.5
Hartford Electric Light Company	23.2	21.0	11.8	1.2
Hawaii Electric Light Company	0.0	3.2	11.2	12.2
Home Light and Power Company	-	-	-	2.8
Missouri Utilities Company	0.0	0.0	93.5	9.9
New Bedford Gas & Edison Light Company	0.0	0.0	0.0	1.3
Old Dominion Power Company	-	-	-	9.4
Puget Sound Power & Light Company	0.0	36.5	0.0	1.8
St. Joseph Light & Power Company	0.0	0.0	0.0	9.3

Statistics of Cluster	(1)	(2)	(3)	(4)
Data Points Evaluated	13	13	13	18
Mean	3.3%	11.0%	21.3%	5.2
Standard Deviation	8.1	12.3	30.1	4.9
Range	23.2	36.5	93.5	18.0

Cluster Membership = 18 Companies

- not available

LIST OF CLUSTER MEMBERS AND OTHER 1980 DATA WHICH COULD AFFECT HOMOGENEITY

CLUSTER NUMBER 5

Company	Nuclear Capacity as a Percentage of Kilowatt Capacity	Hydroelectric Capacity as a Percentage of Kilowatt Capacity	Gas Turbine Capacity as a Percentage of Kilowatt Capacity	Structure Miles Per 1,000 Customers
	(percent)			
	(1)	(2)	(3)	(4)
Arizona Public Service Company	0.0%	0.0%	17.7%	10.5
Black Hills Power & Light	0.0	0.0	46.2	23.1
Central Louisiana Electric Company	0.0	0.0	0.7	5.8
Central Power & Light Company	0.0	0.2	1.3	10.0
Cheyenne Light, Fuel & Power Company	0.0	0.0	0.0	0.5
Community Public Service Company	0.0	0.0	31.3	7.9
Conowingo Power Company	-	-	-	6.0
Delmarva Power & Light Company	4.2	0.0	8.4	6.0
Florida Power Corp.	12.9	0.0	32.4	4.5
Iowa Public Service Company	0.0	0.0	22.7	15.6
Kentucky Utilities Company	0.0	1.3	2.6	11.5
Michigan Power Company	0.0	100.0	0.0	7.0
Missouri Edison Company	-	-	-	0.0
Montana-Dakota Utilities Company	0.0	0.0	18.6	28.4
Oklahoma Gas & Electric Company	0.0	0.0	2.9	7.0
Pacific Power & Light Company	0.8	21.7	0.6	9.5
Public Power Company of Colorado	10.5	10.3	8.0	3.1
Public Service Company of Oklahoma	0.0	0.0	5.1	7.1
San Diego Gas & Electric Company	3.6	0.0	14.6	1.5
Sierra Pacific Power Company	0.0	1.6	7.3	15.8
Southwestern Electric Power Company	0.0	0.0	1.5	8.8
Southwestern Public Service Company	0.0	0.0	2.3	15.0
Texas Power & Light Company	0.0	0.0	0.0	7.3
Tucson Gas & Electric Company	0.0	0.0	14.5	7.3

Statistics of Cluster	(1)	(2)	(3)	(4)
Data Points Evaluated	22	22	22	24
Mean	1.5%	6.1%	10.8%	9.1
Standard Deviation	3.5	21.6	12.7	6.7
Range	12.9	100.0	46.2	28.4

Cluster Membership = 24 Companies

\- not available

LIST OF CLUSTER MEMBERS AND OTHER 1980 DATA WHICH COULD AFFECT HOMOGENEITY

CLUSTER NUMBER 6

Company	Nuclear Capacity as a Percentage of Kilowatt Capacity (percent)	Hydroelectric Capacity as a Percentage of Kilowatt Capacity (percent)	Gas Turbine Capacity as a Percentage of Kilowatt Capacity (percent)	Structure Miles Per 1,000 Customers
	(1)	(2)	(3)	(4)
Boston Edison Company	24.9%	0.0%	8.7%	0.7
Edison Sault Electric Company	0.0	82.9	0.0	17.4
Hawaiian Electric Company, Inc.	0.0	0.0	9.0	2.8
Kingsport Power Company	-	-	-	1.5
Lockhart Power Company	0.0	100.0	0.0	12.4
Massachusetts Electric Company	-	-	-	0.2
Mt. Carmel Public Utility Company	0.0	0.0	0.0	8.1
New Orleans Public Service, Inc.	0.0	0.0	1.4	0.6
Niagara Mohawk Power Corp.	11.8	12.2	5.5	6.2
Orange & Rockland Utilities, Inc.	0.0	4.2	8.1	2.3
Tampa Electric Company	0.0	0.0	6.4	3.2
United Illuminating Company	0.0	0.0	1.3	0.1

Statistics of Cluster	(1)	(2)	(3)	(4)
Data Points Evaluated	10	10	10	12
Mean	3.7%	19.9%	4.0%	4.6
Standard Deviation	8.3	38.1	3.8	5.5
Range	24.9	100.0	9.0	17.3

Cluster Membership = 12 Companies

- not available

LIST OF CLUSTER MEMBERS AND OTHER 1988 DATA WHICH COULD AFFECT HOMOGENEITY

CLUSTER NUMBER 7

Company	Nuclear Capacity as a Percentage of Kilowatt Capacity	Hydroelectric Capacity as a Percentage of Kilowatt Capacity	Gas Turbine Capacity as a Percentage of Kilowatt Capacity	Structure Miles Per 1,000 Customers
	(percent)			
	(1)	(2)	(3)	(4)
Bangor Hydroelectric Company	0.0%	21.8%	0.0%	6.0
Canal Electric Company	0.0	0.0	0.0	0.0
Central Hudson Gas & Electric Company	0.0	4.4	4.3	2.6
Central Vermont Public Service Corp.	0.0	45.3	46.8	5.9
Fitchburg Gas & Electric Company	0.0	0.0	53.9	2.9
Idaho Power Company	0.0	66.7	2.1	18.3
Lake Superior District Power Company	0.0	12.3	15.4	19.2
Madison Gas & Electric Company	15.0	0.0	15.6	2.4
Monongahela Power Company	0.0	0.0	0.0	4.4
Montana Power Company	0.0	45.2	0.0	22.3
Montaup Electric Company	0.0	0.0	6.5	15,666.7
New England Power Company	0.0	29.5	1.1	13,377.6
New Mexico Electric Service Company	0.0	0.0	43.0	10.7
Northern Indiana Public Service Company	0.0	0.6	8.5	6.8
Pennsylvania Power Company	16.5	0.0	4.7	4.4
Public Service Company of New Hampshire	0.0	4.5	7.6	5.9
Rochester Gas & Electric Corp.	41.2	3.9	3.0	3.9
Superior Water, Light & Power Company	0.0	0.0	0.0	7.5
Toledo Edison Company	25.5	0.0	4.4	4.0
West Penn Power Company	0.0	1.4	0.0	3.0
West Texas Utilities Company	0.0	0.0	0.0	24.8
Wisconsin Power & Light Company	12.6	2.2	11.7	8.9
Wisconsin Public Service Corp.	15.4	4.3	10.9	5.8

Statistics of Cluster				
Data Points Evaluated	23	23	23	23
Mean	5.5%	10.5%	10.4%	1,270.2
Standard Deviation	10.8	18.5	15.7	4,195.8
Range	41.2	66.7	53.9	15,666.7

Cluster Membership = 23 Companies

LIST OF CLUSTER MEMBERS AND OTHER 1980 DATA WHICH COULD AFFECT HOMOGENEITY

FORCED CLUSTER NUMBER 8[1]

Company	Nuclear Capacity as a Percentage of Kilowatt Capacity (percent)	Hydroelectric Capacity as a Percentage of Kilowatt Capacity (percent)	Gas Turbine Capacity as a Percentage of Kilowatt Capacity (percent)	Structure Miles Per 1,000 Customers
	(1)	(2)	(3)	(4)
Appalachian Power Company	0.0%	10.3%	0.0%	8.5
Consolidated Water Power Company	0.0	100.0	0.0	69.1
Gulf States Utilities Company	0.0	0.0	1.1	5.2
Indiana & Michigan Electric Company	54.8	0.5	0.0	8.0
Kentucky Power Company	0.0	0.0	0.0	6.7
Louisiana Power & Light Company	0.0	0.0	0.7	4.5
Maui Electric Company	0.0	0.0	0.0	0.0
Minnesota Power & Light Company	0.0	7.8	0.0	19.5
Mississippi Power Light Company	0.0	0.0	0.4	7.8
Ohio Power Company	0.0	0.0	0.0	8.8
Otter Tail Power Company	0.0	0.9	18.0	44.8
Potomac Edison Company	0.0	0.5	0.0	8.5
Public Service Company of New Mexico	0.0	0.0	1.8	7.9
Southern Indiana Gas & Electric Company	0.0	0.0	7.3	6.9
Southwestern Electric Service Company	0.0	0.0	0.0	12.0
Upper Peninsula Generating Company	0.0	0.0	0.0	37,000.0
Utah Power & Light Company	0.0	4.7	0.5	16.2
Wheeling Electric Company	-	-	-	4.6
Wisconsin River Power Company	0.0	100.0	0.0	0.0
Statistics of Cluster				
Data Points Evaluated	18	18	18	19
Mean	3.0%	12.5%	1.6%	1,959.8
Standard Deviation	12.9	32.0	4.4	8,485.4
Range	54.8	100.0	18.0	37,000.0

Cluster Membership = 19 Companies

- not available

[1] Clusters of fewer than ten members, as defined by the clustering program, were grouped together to form larger clusters.

LIST OF CLUSTER MEMBERS AND OTHER 1986 DATA WHICH COULD AFFECT HOMOGENEITY

FORCED CLUSTER NUMBER 9[1]

Company	Nuclear Capacity as a Percentage of Kilowatt Capacity	Hydroelectric Capacity as a Percentage of Kilowatt Capacity	Gas Turbine Capacity as a Percentage of Kilowatt Capacity	Structure Miles Per 1,000 Customers
	(percent)			
	(1)	(2)	(3)	(4)
Alcoa Generating Corp.	0.0%	0.0%	0.0%	500.0
Commonwealth Edison Company	28.9	0.0	6.9	1.0
Connecticut Yankee Atomic Power Company	100.0	0.0	0.0	0.0
Detroit Edison Company	0.0	9.0	4.1	2.0
Duke Power Company	22.1	13.6	0.0	5.0
Florida Power & Light Company	18.2	0.0	15.1	2.0
Georgia Power Company	6.6	5.8	9.6	9.0
Houston Lighting & Power Company	0.0	0.0	11.8	2.0
Indiana-Kentucky Electric Corp.	0.0	0.0	0.0	45,000.0
Ohio Valley Electric Corp.	0.0	0.0	0.0	21,563.0
Pacific Gas & Electric Company	0.5	20.7	4.3	4.0
Southern California Edison Company	2.6	5.2	4.7	3.0
Southern Electric Generating Company	0.0	0.0	0.0	133,000.0
Tapoco, Inc.	0.0	100.0	0.0	56,000.0
Virginia Electric & Power Company	34.2	2.7	0.2	4.0
Yadkin, Inc.	0.0	100.0	0.0	21,000.0

Statistics of Cluster	(1)	(2)	(3)	(4)
Data Points Evaluated	16	16	16	16
Mean	13.3%	16.1%	3.5%	17,318.4
Standard Deviation	25.9	33.3	4.9	35,550.3
Range	100.0	100.0	15.1	133,000.0

Cluster Membership = 16 Companies

[1] Clusters of fewer than ten members, as defined by the clustering program, were grouped together to form larger clusters.

LIST OF CLUSTER MEMBERS AND OTHER 1980 DATA WHICH COULD AFFECT HOMOGENEITY

FORCED CLUSTER NUMBER 18 [1]

Company	Nuclear Capacity as a Percentage of Kilowatt Capacity	Hydroelectric Capacity as a Percentage of Kilowatt Capacity	Gas Turbine Capacity as a Percentage of Kilowatt Capacity	Structure Miles Per 1,000 Customers
	(percent)			
	(1)	(2)	(3)	(4)
Blackstone Valley Electric Company	- %	- %	- %	0.6
Cambridge Electric Light Company	0.0	0.0	35.2	0.0
Commonwealth Edison Company of Indiana, Inc.	0.0	0.0	0.0	28,000.0
Consolidated Edison Company of New York	9.6	0.0	10.2	0.1
Holyoke Water Power Company	0.0	16.5	0.0	0.0
Jersey Central Power & Light Company	32.0	6.2	28.8	2.5
Narragansett Electric Company	0.0	0.0	0.0	1.1
Newport Electric Corp.	0.0	0.0	0.0	1.6
Public Service Electric & Gas Company	14.7	1.9	27.7	0.6
Rockland Electric Company	-	-	-	1.2
Safe Harbor Water Power Corp.	0.0	100.0	0.0	0.0
Sherrard Power System	-	-	-	4.0
South Beloit Water, Gas & Electric Company	0.0	100.0	0.0	1.9
Yankee Atomic Electric Company	100.0	0.0	0.0	0.0
Statistics of Cluster				
Data Points Evaluated	11	11	11	14
Mean	14.2%	20.4%	9.3%	2,001.0
Standard Deviation	30.2	39.7	14.1	7,483.0
Range	100.0	100.0	35.2	28,000.0

Cluster Membership = 14 Companies

\- not available

[1] Clusters of fewer than ten members, as defined by the clustering program, were grouped together to form larger clusters.

Source: NERA computer printout, "Comparison of Electric Utility Clusters," January 10, 1983.

While we have treated "cluster analysis" in the text of this comment as if it were a single and well-understood methodology, it is neither. A variety of statistical methods are available to create relatively homogenous groups from large and diverse populations. None of them is clearly superior by any objective statistical test.

Cluster analysis requires the use of a statistical program to measure the "distance" between members of the population (utilities). In layman's terms, each classifying factor (e.g., size, type of customers, tax burden) is transformed into an index with the same base. The "distance" between two members of the population is determined by combining the differences between them in all classifying factors. For our analysis, we used a method which joins the utilities into groups by combining those which are "nearest" to each other (in technical terms this is an "agglomerative hierarchical" method). We alternatively could have selected a "divisive" method which starts with the entire population in a single group and splits off segments which display the greatest differences. For either the agglomerative or divisive methodology, the factors used to make classifications can be unweighted (as in our example) or weighted. Distances between members of the population can be calculated by combining the differences in individual factors using the "Euclidian" method, which gives equal

* This appendix is intended as a general guide to the alternative clustering methods available and not as a detailed or precise technical description. For a more detailed technical description see: M.R. Anderberg, Cluster Analysis for Applications, New York: Academic Press, 1973, and J.A. Hartigan, Clustering Algorithms, New York: John Wiley, 1975.

weight to factors exhibiting large and small differences (this is the method we used), or the "Minkowski" method (which gives greater weight to factors which are very similar between utilities). Distances between clusters or between an individual member of the population and a cluster can be measured from the point in the cluster which is furthest away ("complete linkage"), closest ("single linkage"), or from the average of points in the cluster ("average linkage"). There are several alternative methods of averaging. We chose the "complete linkage" method.

All of the clustering procedures we have examined use step-by-step rules under which classifications, once made, are not reexamined. Once a member of the population is classified as part of a group (or removed from a group), it remains there throughout the subsequent stages of the analysis even if it is clear, after the fact, that moving it to another group would increase the homogeneity of both groups. Thus not only is there no uniform and agreed-upon method of measuring distances between members of the population or between clusters, but there is also no guarantee that the clusters produced by a given methodology will be the best that could be created using the measurement methods it employs.

It should be apparent from this brief discussion that the use of "cluster analysis" is far from completely objective and that the results frequently will fall short of producing the "most homogenous" groups. The exact methodology used to group utilities would doubtless be the focus of considerable controversy which could not be resolved by any purely objective statistical standard.

P. O. BOX 14000, JUNO BEACH, FL 33408

FLORIDA POWER & LIGHT COMPANY

February 25, 1983

Dr. Bernard Tenenbaum
Acting Chief
Economic Analysis Branch
Office of Regulatory Analysis
Federal Energy Regulatory Commission
Washington, D. C. 20426

Dear Dr. Tenenbaum:

I appreciate the opportunity to comment on the report by Resource Consulting Group, Inc. on an incentive regulation program for the electric utility industry.

After carefully reviewing their work we have concluded that it would not be beneficial for the customer nor the regulated utility industry. My reasons follow on the attached document.

I hope that some of the other companies I sent copies to have also responded to your request.

Sincerely,

B. L. Dady
Vice President
Management Control & Services

BLD:le
Attach.

OPINION OF INCENTIVE REGULATION PROGRAM
OF THE ELECTRIC UTILITY INDUSTRY

Benjamin L. Dady, Vice President
Florida Power & Light Company
February 25, 1983

The Incentive Regulation Plan in brief (as recommended).

Objective: To encourage the utilities to maintain the lowest possible rates to their customers and to reduce the growth and level of their electricity rates relative to those of other firms.

How: As a part of retail and wholesale rates, collect and place in escrow a sum equal to 35% of the base salaries of those executives in the top 0.5% of the firm. If a firm achieves an acceptable rate performance for the year, FERC would release a portion or all of the escrowed funds as a bonus payment incentive. If no bonus or only a partial bonus was due, the excess funds would be carried over to the next year and the rates would be reduced accordingly so as not to exceed the maximum needed in escrow for the next year.

PROBLEMS:

1. There are some unanswered questions that must have a positive response assured before this recommendation can work.

   As pointed out by the consultants, to be effective the state commissions would also have to adopt this procedure. If they did not, the FERC proportionate share generated bonus payment would not be large enough to create an incentive to managers. If FERC rates were increased a sufficient amount to cover the entire payment it would appear to be an undue penalty to wholesale customers when only a minor part of the anticipated benefit of the program would accrue to them.

   FERC needs to apply consistent policies and practices across all regulated electric utilities. The possibility is real that some states will object to this "adder" while some others might endorse it. If so, both the regulated companies and wholesale customers will feel unequal treatment under FERC depending in which state they are operating. As virtually all companies will be "grouped" and comparative results published, state commissions may rely on these relative rankings to establish new rates for the utilities. The hazard in this is that only the state commissions in their oversight role can determine adequate service levels, used and useful utility property, and special situations for the company they regulate. They will not nor should have access to detailed information available from utilities they do not regulate in other states. As a result they will draw inaccurate conclusions and possibly not carry out their responsibilities to either the regulated utilities or their customers.

2. The proposal seems to assume that a utility company's management is primarily motivated by financial reward and there is no conflict of interest if they are rewarded through this mechanism.

   I believe the propo~al ignores the management responsibility to maintain a solvent company and earn a return for its owners. The stockholders of a business rightfully expect the management to be good stewards of their investment. This could mean establishing subsidiaries, holding companies or taking such dramatic steps as American Telephone & Telegraph to earn a profit for those who have placed their savings at risk to capitalize the company. A bonus payment to management by any incentive mechanism of a regulatory agency strikes a conflict of interest in the minds of the owners. That is, is the management really making fair tradeoffs between the stockholders interest and the customers interest or is he/she now motivated by this incentive mechanism to line his/her own pockets at their expense?

3. The proposal does not consider the complexities of estabishing competitive salary levels.

   Competitive salary levels have traditionally and usually been set by a company based on its ability and need to attract, retain and reward its employees.
   The principles of an effective executive compensation program dictate that salary compensation be comprised of two parts, base salary and bonus, together equaling total cash compensation. The levels of the two components are set by determining what portion of the salary should be fixed (base pay) or in essence guaranteed, and what portion should be put at risk (bonus) dependent upon the attainment of individual, department or corporate goals. We question the ability of any industry-wide bonus program to be an accurate and fair measurement of the attainment of these types of goals. If the second dimension is regulated by a third party, it would create an impossible environment to effectively and appropriately regulate salary levels. If salary levels are not competitive or are restricted because of an inaccurate industry-wide performance measurement, it would create serious inequities with salary relationships for comparable positions. On the other hand, if a company were to continue to provide competitive levels of compensation without regard to this third party bonus program, then it would be extremely difficult to justify payment of a bonus that rewards an individual as much as 35 percent over

the competitive level. In other words, it is not possible for the company to control the base salary while a government agency regulates the bonus dimension of salary. The obvious results would be extremely bad. First, eventual government involvement in setting the level of base salary (which the report indicates is not the intent); and second, base salary and total compensation levels established with little or no regard for what comparable positions are paid in other industries.

We are concerned the outcome would be contradictory to what we need to recognize and achieve, and that is that utility executive skills are comparable to the executive skills in any industry and should be valued in a comparable labor market and by comparable methods. To do otherwise would syphon talent from this industry and prohibit the attraction of needed talent from other industries.

From a different point of view, we are not sure the FERC program is within the legal confines of the Anti-Trust Act.

4. The proposal seems to underestimate the complex tradeoff already being taken by utility managements.

To effectively manage a utility the leadership must conscientiously make the necessary tradeoffs. Adding a "regulatory imposed bonus system" would add another complex issue to the job. Consider a few of the choices now being made:

A. Between the quality of service a customer "desires" and what he/she and the stockholders can afford;
B. Between the desires of a Commission to have the lowest rates and the stockholders who would desire higher rates;
C. Between the desires for great financial flexibility on the market with an AAA rating and the cost to the common stockholder by dilution of common stock and/or the customers through poorer service to achieve that flexibility,
D. Between the long term capital solution and the short term O&M tradeoff.

Depending on the criteria chosen to award an incentive, a company's management may make some poor operating decisions. For example, they may see that they are near an award and by deferring tree trimming or needed maintenance they would be able to win the bonus.

5. Aggregate cost performance measurements over a five year period of time sounds reasonable but what do they really mean in our business.

Power plants have a 10 to 12 year planning horizon. The transmission line planning horizon is 3 to 12 years and the entire system reliability scheme is developed over the life of the utility.

One good decision to build a plant based on the facts available and reasonable estimates of the future may look foolish in the light of bountiful reserves 10 years later. Yet to have a plant when needed before OPEC and useful conservation measures took place, construction had to begin years ago. This situation can show a well managed company which used the state-of-the-art forecasting and decision making processes in a bad light for many "five year periods".

One bad decision to not build a plant by ignoring an obvious need and hoping that someone would bail them out could be hailed as "enlightened" management worthy of great incentive rewards 10 years later when neighbors really do have too much capacity. Yet which company really did their homework and attempted to meet the needs of their customers? Which shareholders took the risk?

The truth is, someone would have to play Solomon to go back in time and judge not just one but many decisions that currently affect performance, for good or ill, to determine in which "group" the utility should be placed.

The lowest possible rate growth in an inflationary environment can be achieved by minimum construction. Thus, by failing to plan and build for future need, rates would be kept low over the short to intermediate period (1 to 10 years).

6. Virtually all ratios have their pitfalls. Every utility has a situation beyond the management's control in the past that will make them look good or poor under certain indicators. I've looked at many and although they are helpful, I find it difficult to draw definitive conclusions from comparisons with other utilities unless I understand their accounting practices and historical background.

It is my opinion that for an incentive to be effective it must be easily understandable. I currently have access to much comparable data through the Dow-Jones Service, Compustat. I could read the numbers and see how we compared with other utilities in our "Incentive Group". If each utility had a series of special cases, and they should, that cause their numbers to be something different than published data, what incentive would that be to us? If one cannot clearly and easily understand the system, interest would be generated equivalent to a lottery. Win some, lose some, but we cannot control our fate.

In Conclusion

It is my recommendation that FERC recognize that however noble this proposal, to think that an incentive payment to managers would produce lower rates is not likely to happen. In practice it would be an administrative nightmare for FERC and State Commissions. It would take many personnel to track down the special considerations and it is unlikely that the ultimate customer would benefit from it. FERC should not make an attempt to usurp the responsibility the management has to its owners. FERC should recognize the complex issues public utility managers are already dealing with, and consider the decisions for utility rate base and operating costs on a case by case basis.

State of Florida

Joseph P. Cresse
Commissioner

FLETCHER BUILDING
101 EAST GAINES STREET
TALLAHASSEE 32301
(904) 488-2986

Public Service Commission

January 19, 1983

Dr. Bernard Tenenbaum
Acting Chief
Office of Regulatory Analysis
Federal Energy Regulatory Commission
Economic Analysis Branch
825 North Capitol Street, N.E.
Washington, D.C. 20426

Dear Dr. Tenenbaum:

Thank you for your letter of December 7, 1982, enclosing a draft of the report Incentive Regulation in the Electric Utility Industry and for inviting our comments. As you know, this Commission has had a continuing interest in incorporating incentives into the regulatory process.

Because this is your consultant's draft report and not the recommendation of the FERC staff my comments are fairly general. I would, however, very much appreciate being kept abreast of the report's progress and evolution and may wish to comment further when it approaches its final form.

The report is certainly comprehensive in suggesting that the best indicator of utility performance is simply total revenues from the sale of electricity divided by total wholesale and retail KWH sales plus losses. Such an all-encompassing measure reflects a utility's total electricity costs, including a return, as perceived by the ratepayers. The report is also rather novel in its premise that the most effective way to improve performance is to distribute any incentive award directly to the utility managers most responsible for that improvement. Under the recommended program the maximum incentive award available to a utility is set at 35% of the sum of the base salaries for those executives whose salaries are in the top 0.5% of all salaries paid by the company. The selection of key managers and distribution of that award among them is left to the utility's board of directors and executive compensation committee.

The actual measurement and evaluation of performance, however, may well be considerably more difficult than the authors make it sound. In the envisioned program a utility's performance, i.e., revenue per KWH, is evaluated in terms of both absolute level and rate of increase over time against the average performance of a selected group of like utilities. Given the hundreds of factors that can affect the price of electricity I have some reservations as to whether truly comparable groups can be selected and as to how meaningful the resultant comparisons would be. Further, the inevitable utility wrangling over whether a particular company ought to be included in a particular group would be a regulatory nuisance. Other aspects of the program that I have some question about are why participation should be voluntary and what the value of a given utility's improvement (relative to others in its group) is to its ratepayers compared to the size of the incentive award the managers receive.

Nevertheless, as anyone who has delved into this subject knows, there are no perfect answers. I think your effort in this area is laudable and I look forward to any further developments.

As you are aware, we currently have our own Generating Performance Incentive Factor which focuses on power plant availability and heat rate. While we can't be sure it was because of GPIF, we have noted improvements in both measures since the program was put in place. I would agree with the assessment of the report's authors, however, that a GPIF-type program is probably administratively infeasible for FERC.

If we can help you in any way please let us know.

Sincerely,

Joe Cresse

JOSEPH P. CRESSE
Commissioner

JPC/JH/cd

IOWA STATE COMMERCE COMMISSION

Commissioners
Andrew Varley
Christine A. Hansen
Paul Franzenburg

Executive Secreta .
Robert G. Holetz

June 14, 1983

Dr. Bernard Tenenbaum
Acting Chief
Economic Analysis Branch
Office of Regulatory Analysis
Federal Energy Regulatory Commission
Washington, DC 20426

Dear Dr. Tenenbaum:

I found the report on "Incentive Regulation in the Electric Utility Industry" interesting and useful. I agree with its goal, although I disagree with certain recommendations. Time does not permit a detailed response, however, I do wish to offer the following observations, comments, questions, etc.:

> The report appears to gloss over the most difficult aspect of the problem (i.e., performance measurement and inter-utility comparisons) and devotes much attention to the second aspect of the problem (i.e., incentives).
>
> I recommend that FERC devote its subsequent efforts in this area to only the steps 1 and 2 outlined on page 4.5 (i.e., clustering of utilities and calculating static performance measures) and subject the results to peer review before proceeding to the subsequent steps outlined by the author.
>
> It would appear that "incentives" are best left to state regulatory agencies. They have differing needs, philosophies, etc. But FERC could provide a useful service by providing data upon which to base state decisions.
>
> I agree on the use of aggregate measures of performance. These provide greater management flexibility and are most likely to lead to near optimum results. We have adopted a similar philosophy (see attached) in our new Operations Review Division. Of the four alternatives, I prefer Alternative B.

I agree on the use of incentive compensation plans to reward good performance. My understanding is that financial rewards to stockholders would not be permitted by our Commission, although penalties for poor performance are permissible.

Finally, these comments are offered in my capacity as Division Director. They may or may not reflect the views of the Commission. I look forward to your subsequent drafts of this report. Please call me on (515) 281-3771 if I may be of further assistance.

Sincerely,

Enver Masud

Enver Masud, Director
Operations Review Division

EM/sm
Attachment
cc: Chairman Varley
Section Chiefs, ORD

Incentives Proposed for Iowa Investor Owned Electric Utilities

Operations Review Division
Iowa State Commerce Commission

PRINCIPLES

Measure of Efficiency
The customer purchases kilowatthours of electric service, Btu's of gas service, or minute-miles of communications service.
The customer considers the utility efficient if service is purchased at the lowest reasonable cost.

Cost of Service
Utilities are reimbursed for cost of service.
Utilities are disallowed costs which are not reasonable or prudent.

Accountability
The customer holds the utility accountable for efficiency.
Utility's directors must hold their managers accountable for efficiency.

PENALTY

Penalty = kWh (A - B)/X

kWh = kilowatthours sold by company during last year.

X = 5 in year 1
4 in year 2
3 in year 3
2 in year 4
1 in year 5 and later years

Alternative A

A = company three year average revenues per kWh.

B = mean of three year averages (revenues per kWh) of all companies in the group.

Aom = company three year average operation and maintenance expenses per kWh.

Bom = mean of the three year averages (operation and maintenance expenses per kWh) of all companies in the group.

If A is less than B, and Aom is less than Bom, company performance is rated A or EXCELLENT.

If A is less than B, and Aom is greater than Bom, company performance is rated B or GOOD.

If A is greater than B, and Aom is less than Bom, company performance is rated C or FAIR.

If A is greater than B, and Aom is greater than Bom, company performance is rated D or POOR, and company is penalized.

Alternative B

A = company three year average revenues per kWh.

B = mean of three year averages (revenues per kWh) of all companies in the group.

Aom = company three year growth rate of operation and maintenance expenses per kWh.

Bom = mean of the three year growth rates (operation and maintenance expenses per kWh) of all companies in the group.

If A is less than B, and Aom is less than Bom, company performance is rated A or EXCELLENT.

If A is less than B, and Aom is greater than Bom, company performance is rated B or GOOD.

If A is greater than B, and Aom is less than Bom, company performance is rated C or FAIR.

If A is greater than B, and Aom is greater than Bom, company performance is rated D or POOR, and company is penalized.

Alternative C

A = company three year average revenues per kWh.

B = mean of the three year averages (revenues per kWh) of all companies in the group.

If A is greater than B, company is penalized.

Alternative D

A = company three year average revenues per kWh.

B = lowest of the three averages (revenues per kWh) of all companies in the group.

All companies other than the best (i.e., lowest three year average) are penalized.

REWARD

Companies not penalized may reward their officers provided that their incentive plan balances the stockholder's and consumer's interests. Commission may set equity return, within the range of reasonableness, to correspond to company performance rankings.

BIBLIOGRAPHY

1. Utility Management Compensation Strategies and Issues, Public Utilities Reports, Inc., The Management Exchange, Inc., June 1982.

2. Incentive Regulation in the Electric Utility Industry, Resource Consulting Group, October 15, 1982.

3. Measuring Productivity of Electric Utilities, National Economic Research Associates, Inc., May 1982.

4. Smith, Edward J., Jr., The Measurement of Electric Utility Cost Performance, February 6, 1976.

Merrill Lynch
Pierce
Fenner & Smith Inc.

January 13, 1983

Dr. Bernard Tenenbaum
Acting Chief
Economic Analysis Branch
Office of Regulatory Analysis
FEDERAL ENERGY REGULATORY COMMISSION
825 North Capitol Street
Washington, D.C. 20426

Dear Dr. Tenenbaum,

I read over Incentive Regulation in the Electric Utility Industry as requested. My comments are too numerous to deal with other than briefly. If you want more detail, please call me.

1) If you want to get the backing of the utilities for an experiment, I suggest a clear hold harmless provision, so that no company loses by participating. The goal in my view, is to find out how a plan would work by trying it.

2) The grouping on p. 2.17 may remove incentives to change company characteristics in a way to improve costs overall. I'd rather have no groupings and look for improvements or absolute levels of efficiency.

3) The reward could come from a pot into which all utilities contribute, and the penalty could be the contribution itself.

4) The reward scheme (p. 3.2) completely leaves out the owners of the business. I do not believe that it is warrented to dismiss the impact of outside directors or shareholders. Perhaps the incentive should come in the form of a bonus to shareholders, as proposed by Doris Kelley last year.

5) The analysis of benefits (p. 3.4) seems to ignore the possibility that continuous increases in efficiency could provide a significant percentage of a firms growth.

continue.........

6) The proposal to divorce management from ratemaking (p. 3.5) leaves much to be desired, in my view. That is one of managements most important functions.

7) Why is it politically saleable to give incentives but not have penatlies (p. 3.7).

8) Management worth its salt will want incentive compensacion (p. 3.7).

9) I am not certain that FERC controls enough revenues in most firms for them to care what FERC does in the incentive area. Nor do I believe that the large states will follow FERC, because most regulators in large states think, in my estimation that they are way ahead of FERC anyway.

10) If FERC sets a generic rate of return and limits rate adjustments to fixed intervals, this whole elaborate incentive scheme is unnecessary.

11) A good gameplayer will find a way to beat the scheme (p. 4.6).

12) What is a good weighting and why (p. 4.7)?

13) The utility may have its own incentive scheme which will be affected by profitability or efficiency. Why should you require a certain type of distribution (p.4.9)?

14) Comments on thousands of shareholders (p.4.10) ignore directors as the agents of the shareholders.

15) Regulators already do look at performance informally, or even formally (p.4.11).

17) Considering that the Alaskan pipeline may never get off the ground, why even dicuss those incentives(p. 5.2)?

18) The downgrading by Moody's (p. 5.6) deserves real exploration.

19) Is something wrong with the Davis-Besse dates (p. 5.9)?

20) I find no discussion of utilities that have made efficiency improvements without a formal efficiency program, and what happened and why?

continue..........

Aside from the nitpicking, an experiment in this field is a good idea, but I get the feeling that the proposed scheme is needlessly complicated, loses by leaving out the owners of the business, and may not have much impact because FERC regulation is not important enough to most utilities.

If I can be of more help, please call me.

Yours truly,

Leonard S. Hyman
Vice president

LSH/jm

The National Regulatory Research Institute

OSU The Ohio State University

2130 Neil Avenue
Columbus, Ohio 43210
614/422-9404

January 31, 1983

Dr. Bernard Tenenbaum
Acting Chief
Economic Analysis Branch
Office of Regulatory Analysis
Federal Energy Regulatory Commission
825 North Capitol Street
Washington, DC 20426

Dear Bernie:

We appreciated being among those who were asked to make some commentary on the RCG, Inc. draft report on incentives and utility performance. As you may recall, we have produced several reports ourselves on this difficult but tempting subject. (I'm enclosing three of them.)

As an efficient - if not the most graceful way of transmitting the comments of Institute professional staffers (two economists and a nuclear engineer) who have read the piece, I'm sending along the originals of their "internal" memos to me. I hope you will see them as constructive, in addition to candid.

Best regards,

Doug

Douglas N. Jones
Director, and Professor of
Regulatory Economics

es
Encls.

FROM: Steve Henderson *JHN*

TO: Kevin Kelly

DATE: January 26, 1983

SUBJECT: Draft Report: Incentive Regulation in the Electric Utility Industry

This report suggests an incentive scheme to improve overall electric utility performance by making certain incentive awards to top managers based upon static and dynamic comparisons of the utility's final average prices in relation to those of other utilities with similar characteristics.

Overall, the report has done a good job in considering the multitude of factors that can affect the operation of an incentive scheme such as this. The program is aimed at overall performance, and not one segment such as generation. As such, it should not induce management to inefficiently emphasize one production phase or process in favor of another.

The amount of money needed to elicit the same performance may be smaller if paid directly to management rather than to stockholders, as the report suggests. Although I suspect the report may be correct about this, such a result is by no means obvious. In particular, the report does not consider what may be the biggest drawback to such a management bonus scheme--the reaction of the stockholders. I wonder whether stockholders would stand by passively and continue to remunerate their managers in the same way after the regulator had adopted a bonus plan linked to price reductions. The stockholders' and regulator's interests are not the same in this matter. Supposing that stockholders are mostly interested in increasing profits, both the regulator and equity owners are interested in reducing costs so there is no conflict in this regard. Profit maximizing stockholders, however, are presumably in favor of raising prices (assuming that regulation has been successful in reducing prices to begin with) while the regulator's bonus plan would encourage managers to reduce prices. The report is aware of this conflict but addresses the issue only as it pertains to the management-regulator negotiations about the allowed rate of return. (The report suggests grouping utilities into risk classes with each rate of return set for each such class. This eliminates the incentive for managers to request a lower rate of return, hoping thereby to reduce prices and obtain a larger bonus from the regulator.) The emphasis on strategic behavior regarding the rate of return may be misplaced. A more important issue may be the potential strategic behavior of the stockholders to counter the regulator's bonus plan. That is, the regulator can induce managers to reduce prices with a bonus plan. Likewise, the self interest of the stockholders may lead them to pay their managers a bonus for better profit performance. The fact that relatively few electric utilities use such bonus plans currently is not a good indication that stockholders will remain passive in the future. In addition to using bonus plans, stockholders have the ultimate option, exercised infrequently to be sure, to fire managers. In the face of such strong interest, is it possible that the regulator's bonus plan could be effectively countered by stockholders—perhaps not immediately but in the long run? The answer to that question seems important and the report does not address it.

The clustering of firms into comparable groups is considered fairly carefully by the report. Statistical cluster analysis combined with expert judgment should provide comparable firms. I wonder if the sample sizes in each cluster will be large enough, however. The clustering will necessarily be imperfect. But, that imperfection is not in itself sufficient reason to discard the whole idea. Any type of regulatory substitute for competitive pressure is imperfect, including conventional rate-of-return regulation. The question is which type of regulation most closely mimics competition. It may be that the ability of stockholders to counter the regulator's bonus plan, for example, is imperfect and the suggested incentive plan is superior to conventional rate-of-return regulation with its imperfections. It is difficult to know in advance which might be better. The stockholders incentive to counter the plan, however, seems like an important consideration in weighing these two alternatives.

SH/me

The National Regulatory Research Institute

The Ohio State University

2130 Neil Avenue
Columbus, Ohio 43210
614/422-9404

MEMORANDUM

TO: Doug Jones

FROM: Kevin Kelly KK

DATE: January 27, 1983

SUBJECT: "Incentive Regulation in the Electric Utility Industry"

As you requested, two economists in the Electric and Gas Division, Dr. Stephen Henderson and Mr. William Pollard, have reviewed the report on incentive regulation in the electric utility industry. Recall that Steve was co-author of the NRRI report, Regulation as a System of Incentives, and that Bill was principal author of Rate Incentive Provisions: A Framework for Analysis and a Survey of Activities. So, each has some familiarity with the subject matter.

I have not read the report and the main purpose of this memo is to transmit Steve's and Bill's comments to you. However, I have "looked through" the report, and I'd like to suggest a context for thinking about it.

The regulatory incentive concept is of great interest to regulators and even to the regulated utilities, as we have seen from our own experiences. Besides interest in the two reports mentioned, there was a lot of good commentary on the incentives portion of our workshop on electric construction cost overruns and on our working group of commission staffers dealing with ways in which commissions could measure power plant productivity and give utilities an incentive to improve it.

Despite this interest, the problem of devising a set of regulatory incentives is a tough one. It involves being fair with regard to both the utility (avoiding unintended and undue penalties) and to the consumer (avoiding "excess" profits). It involves thinking through whether the incentive could lead to unintended and undesirable utility behavior. Importantly, it involves deciding whether the incentive mechanisms should be based on a comparison of similar companies or a comparison of one company's performance with its own performance in prior years. This report chooses the former approach, but perhaps the latter approach would be more appropriate during an implementation period for testing incentive regulation and for testing measures of performance. (Recall that our report, The Measurement of Electric Utility Performance, considers both approaches and discusses the difficulties associated with each.)

Because the problem is a tough one, any preliminary attempt to define an incentive mechanism will be imperfect and, hence, subject to proper criticism. Such will probably be the case with this draft report. I would hope that criticism does not deter the FERC from continuing to investigate the incentive regulation concept, whether with the specific incentive device proposed here or not.

The National Regulatory Research Institute

The Ohio State University

2130 Neil Avenue
Columbus, Ohio 43210
614/422-9404

MEMORANDUM

TO: Dr. Douglas Jones, and Dr. Kevin Kelly

FROM: William Pollard

DATE: January 27, 1983

I have given a cursory reading to the report, Incentive Regulation in the Electric Utility Industry. My initial reaction is essentially negative. Resource Consulting Group, Inc., by advocating their particular approach, fails to examine carefully all aspects of their approach. Furthermore, alternative approaches are not given a fair review. I will point out what I consider to be grave problems with the approach advocated by RCG, Inc.

The performance measure is based on an index of average revenues. RCG, Inc. fails to mention the fact that this measure introduces commission behavior into the performance measure. The consideration of comparable regulatory policies among state commissions must be added to the idea of comparable utilities. Treatment of expense and rate base items varies among the states. A utility's rates may be low or high relative to rates charged by other utilities simply because certain expense or rate base items may or may not enter the revenue requirement. RCG, Inc. does not discuss the role of state commissions in this regard.

RCG's lack of insight is not limited to just this analytical error. RCG realizes that a performance measure based on average revenues, when linked to executive compensation, could create a conflict between management and shareholders. They state: "...if an incentive bonus is awarded on the basis of average revenue performance, management may be encouraged to argue for an otherwise low rate of return on equity as a means of improving its average revenue per kWh performance. In general, we recommend the generic rate of return approach to eliminate this potential conflict between management and shareholders (pg. 3.5)." If the rate of return were the only factor determining the return to the stockholder, this solution might have merit. However, I doubt management would fail to recognize its financial interest simply due to separate hearing. The mistake in the analysis is more fundamental than this. Management may have an incentive to argue that certain items should not be included in the rate base and that certain expenses incurred may not be fully passed through to consumers. This could occur simply because a sufficiently strong case is not presented by management or they are excluded from the rate case. No matter how real this behavior, it is a possibility raised by the incentive program that RCG advocates. RCG fails to address this possibility.

Finally, beyond a short discussion of why the program should apply to both wholesale and retail sales, RCG, Inc. does not address the potential impact of the program on the composition of the utility's sales.

In summary, it is hard to find merit with the RCG's report. The analysis is incomplete and sometimes inadequate.

WP/sam

Office of the
Consumers' Counsel

William A. Spratley, Consumers' Counsel (614) 466-8574

137 East State Street
Columbus, Ohio 43215

March 4, 1983

Joan Simmons, Director
Intergovernmental Affairs
Federal Energy Regulatory Commission
825 N. Capital Street
Washington, D.C. 20426

RE: Incentive Regulation Report

Dear Ms. Simmons:

Pursuant to our conversation several weeks ago concerning the Incentive Regulation draft report prepared by Resource Consulting Group, the Ohio Consumers' Counsel presents the following comments:

1. The award system fails to identify either specific management actions or specific customer benefits for which awards would be warranted.
2. The absence of negative awards fails to reflect the competitive market wherein both positive and negative awards assure optimum service at minimum cost.
3. The award system is focused more upon an existing condition rather than upon influencing management decisions at the margin.
4. Line loss inclusion in the sales component does not serve to minimize line loss.
5. Insufficient criteria have been developed to identify "comparable" companies.
6. An effective system of positive and negative awards would require uniform application in the regulatory process.

Thus, Consumers' Counsel recommends against the adoption and implementation of the draft report as presented. Incentive regulation does have merit and it should be pursued on a more rigorous basis. Please keep our office advised on any further developments as we wish to participate in this effort.

Sincerely,

Timothy C. Jochim

Timothy C. Jochim
Associate Consumers' Counsel

TCJ:SAC

Southern Company Services Inc
Perimeter Center East
Post Office Box 720071
Atlanta, Georgia 30346
Telephone 404 393-0650

Donald R. Wells
Manager
Compensation and Benefits Department

Southern Company Services
the southern electric system

January 27, 1983

Dr. Bernard Tenenbaum
Acting Chief
Economic Analysis Branch
Office of Regulatory Analysis
Federal Energy Regulatory Commission
825 North Capitol Street
Washington, DC 20426

Dear Bernie:

Enclosed are marked up pages which reflect the revisions we discussed by telephone. Please call me if you have any questions.

Yours very truly,

Don

bl

enclosure

After the potential CFPC bonus awards for participants are established, they are adjusted to reflect Utility C's financial performance relative to an absolute ROCE target established by the company's Board of Directors for that four-year period. For example, the company's initial PIP plan specifies that the potential CFPC bonus award (as determined by the job evaluation rating system described above) for the 1982-1985 plan period should be multiplied by the adjustment factors shown below in computing the CFPC bonus award for each participant. Under this adjustment scheme, a participant's potential CFPC bonus award will be adjusted upward by a factor of 1.25 if Utility C earns an average ROCE of 18 percent during the 1982-1985 plan period. Similarly, if Utility C earns an average 13 percent ROCE during this plan period, each participant's potential CFPC bonus award will be adjusted downward by a factor of 0.75. Adjustment factors for ROCE levels between those shown in the table are essentially determined by linear interpolation.

ADJUSTMENTS TO POTENTIAL CFPC BONUS AWARDS

ROCE Achieved (%)	18.00	14.50	14.00	13.50	13.00	12.50
Adjustment Factor (%)	125	100	75	50	25	0

The actual CFP bonus award that a participant receives is finally determined by Utility C's relative ROCE performance. Specifically, if Utility C's four-year average ROCE is not equal to or greater than the four-year average ROCE earned by the four utilities with the highest four-year average ROCE in the 16-utility peer group, ~~a PIP participant cannot receive more than 75 percent of his adjusted potential CFPC bonus award~~ (see table on following page). Also, a participant will receive no CFPC bonus award, regardless of the degree to which the company's ROCE goals are achieved, unless Utility C's four-year average ROCE is greater than the average ROCE of the eight utilities with the lowest four-year average ROCE in the

the Adjustment Factor (%) applied to a participant's Potential CFPC Bonus Award is limited to a maximum of 75%.

16-utility peer group.* A new four-year measuring period begins each year to recognize the need to link objectives over longer periods of time, to recognize changes in the operating environment, and to encourage participants to make optimal long-term decisions.

RELATIVE ROCE RANK AND ACTUAL CFPC BONUS AWARDS

Relative Rank of Four-Year Average ROCE for Utility C	Actual CFPC Bonus Award as Percentage of Adjusted Potential CFPC Bonus Award
4th Quartile of Peer Group Utilities	~~100~~ No Limit
3rd Quartile of Peer Group Utilities	75
2nd Quartile of Peer Group Utilities	0
1st Quartile of Peer Group Utilities	0

Program Administration

An individual PIP participant's performance is evaluated under the program by a formal annual evaluation procedure. At the start of each year, the participant, his immediate supervisor, and the next level supervisor agree on three to five written objectives. These objectives are linked to strategic and business plans, relevant financial and operating objectives, departmental plans, and individual accountability. During the year, a participant's performance may be informally reviewed periodically. The participant's performance is reviewed formally in writing at the end of the year. Bonus award recommendations are then

* In a manner consistent with the IPC bonus awards, no CFPC bonus awards will be made if Utility C is unable to fund its current dividend out of current earnings.

VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

WILLIAM W. BERRY
PRESIDENT
AND
CHIEF EXECUTIVE OFFICER

February 25, 1´ 3

Dr. Bernard Tenenbaum
Acting Chief
Economic Analysis Branch
Office of Regulatory Analysis
Federal Energy Regulatory Commission
Washington, D. C. 20426

Dear Dr. Tenenbaum:

In accordance with your request, Vepco has reviewed the draft report, Incentive Regulation in the Electric Utility Industry, prepared by Resource Consulting Group for the FERC.

You will note from the enclosed comments that while Vepco agrees in principle with the idea of incentive regulation, we have some concerns over certain aspects of the RCG proposal. However, Vepco does feel that even in view of these concerns, RCG should be commended for their attempt to provide an unbiased program for incentive regulation.

We hope these comments will prove useful to the FERC and RCG as you continue to examine the issue of incentive regulation.

Sincerely,

William W. Berry

Enclosures

Comments on
Incentive Regulation in the Electric Utility Industry
by
Virginia Electric and Power Company

Virginia Electric and Power Company (VEPCO) has reviewed the Draft Report entitled "Incentive Regulation in the Electric Utility Industry" prepared by Resource Consulting Group, Inc. (RCG) for the Federal Energy Regulatory Commission (FERC). The Company's thoughts and comments on the draft report follow.

In Vepco's opinion, RCG should be commended for its objective analysis of the issue of incentive programs in the regulated electric utility industry. The recommended program of incentive regulation as detailed in Chapter 4 of the draft report is, in theory, a well balanced approach to a sharing of benefits between the utility and its customers.

Vepco is an advocate of management incentive programs and the objectives they are designed to obtain. In fact, a management incentive program has been in operation at Vepco for approximately two years.

Although Vepco does support management incentive programs, certain aspects of the program recommended by RCG are troublesome. Even though the theory and objectives of such programs are laudible, the practicability and applicability of such proposals must be considered. The implementation of a management incentive program requires an effective comparison and evaluation of the utilities that satisfies all concerned parties (i.e. utilities, customers, stockholders and regulators). This is an extremely difficult and complex problem. Generally speaking, the measurement and grouping methodology as proposed by RCG seems to be inadequate in meeting this requirement. Additionally, some of the proposed methods are apparently arbitrary and difficult to communicate.

The comments that follow will delineate some of our concerns. These comments are structured as follows: (1) General comments on the proposal, (2) Comments related to the Measurement of Performance, and (3) Comments on the Additional Incentive Program Possibilities. There are also two appendices attached. Appendix A is a summary of the Vepco Management Incentive Plan, and Appendix B is the settlement agreement of a recently filed incentive plan negotiated by the FERC Staff, Vepco and its customers pursuant to an order of the Commission in Docket Nos. ER81-388-000, ER78-522, IN80-14, EL80-9, and EL80-16.

In Vepco's management incentive plan, there are two corporate performance measures; earnings per share, and a dynamic measure of average revenues per kilowatt hour. Vepco's internal plan takes into account the interest of the stockholder and ratepayer. The utility executive strives to provide the best return to the stockholder consistent with least costs to the ratepayer. In comparison, the ratemaking process requires the establishment of the fair and reasonable return on equity in setting the proper revenue requirement. Once the revenue requirement and associated price per KWH are set, the process of cost minimization, and possibly its attendant increased earnings per share are directly related.

There are also important differences between Vepco's use of a dynamic measure of average revenues per kilowatt hour and the RCG proposal. In Vepco's plan, this measure is used to determine whether or not any monies should be distributed. Also, it determines if Vepco did better or worse than an average. Vepco strives to achieve this goal but failure does <u>not</u> necessarily indicate inadequate performance.

Vepco is committed to the use of internal management incentive programs. Because of this committment, no program adopted by a regulatory agency should preclude the utility from developing and administering incentive plans internally. No such suggestions appear in the RCG proposal but it is an important point that deserves emphasis.

Several aspects of the FERC Performance Incentive Program deserve comment with respect to the difference between it and the RCG proposal.
The order of the Commission States:

> "The Commission believes it necessary that there be an incentive for VEPCO to continue to improve its performance in the future. Commission staff and the parties will negotiate a sliding rate of return tied to generating unit performance based on indices such as equivalent availability and heat rate to be applied in Docket No., ER82-423-000 and future rate proceedings. All parties, including staff, are also urged to consider the use of a maintenance cost tracking provision".

It is important to note that by Commission order, the focus of the program was limited to generating unit performance, and that the target of the program was to be rate of return. As is obvious from Appendix B, the program as developed focused on overall cost performance as best as possible within the confines of the Commission order. It is also important to note that the program ultimately developed was the result of negotiations among the parties and thus reflects a balance of differing views of each party to the negotiations and cannot be construed as solely the views of Vepco.

The above comments concerning the FERC Performance Incentive Program must be considered in any attempt to relate Vepco's comments on RCG's proposal to the FERC Performance Incentive Plan under which Vepco is currently operating.

General Comments

Vepco finds itself in agreement on a number of issues raised by RCG in its draft report. An incentive program aimed at cost minimization should focus on aggregate cost rather than on a selected subset of costs. Any incentive program should also consider both long run and short run considerations. Vepco also agrees that Total Factor Productivity measures are "conceptually" attractive, but the practical issues involved in adopting this approach would be almost impossible.

While agreeing in principle with the use of aggregate total cost minimization measures, the idea that aggregate unit cost is a logical extension does not necessarily follow. Furthermore, the actual "cost" measure proposed by RCG is revenues per KWH plus losses, which may well deviate from cost per KWH.

Vepco agrees that the incentive program should not focus on an adjustment to the rate of return in the incentive plan. As discussed in the draft report, the cost of capital may rise due to the increased uncertainty surrounding returns, and this may ultimately result in factor input substitutions. In addition, the utility should be exempt from incentive payments and/or penalties resulting from the occurrence of events beyond the utility's control. Also, there is a need for a "game" proof program. Finally, Vepco considers the idea of a "deferred penalty dollar" system a crucial element when performance is based on a relative comparison among utilities, rather than individual utilities meeting absolute standards.

We interpret the underlying "invisible hand" mechanism that insures utilities positive response to the RCG incentive program to be a simulation of competitive cost minimizing responses from utilities relative to one another. This would be accomplished by constructing an index of performance being constructed for each utility vis a' vis other "comparable" utilities. In the competitive market model, socially optimal results are obtained by the "forces of the market". A key element in the attainment of these desired end results rests upon (among other things) competition among firms in the same market, selling of a homogeneous product, and the direct interaction of consumers and producers, with consumers acting so as to maximize their satisfaction, and producers acting so as to maximize profits.

In the regulated sector of the economy, regulators are a wedge between consumers and producers, and firms do not compete in the same market. This proposal, by forcing firms to compete across markets, may therefore have the undesireable affect of reducing the cooperation and communication between firms since they would now be competing for incentives. Due to these differences, it is not clear to Vepco that competition among firms in segmented markets, on the basis of ex-post revenues per unit of output, will produce socially desirable results.

Comments on the Measurement of Performance

In their proposal RCG has recommended the use of revenues per kilowatt hour as the basic measure of firm performance. This basic measure will then be utilized to construct two additional measures, a static performance measure, and a dynamic performance measure. The static measure would direct attention to the <u>level</u> of revenues per KWH, while the dynamic measure would focus on the change in the level of revenues per KWH over time. A weighted combination of these measures would be constructed relative to other comparable utilities to ultimately derive the incentive dollars or penalty points that accrue to the utility. This approach raises the following issues of concern to Vepco:

1) Should <u>average</u> revenues/costs be the focus of performance measurement?
2) Is revenue per KWH a viable proxy for costs per KWH?
3) Can a "reasonable" definition of comparable firms be developed in the context of the proposed program?

As indicated previously Vepco concurs with the notion of focusing on aggregate cost given the objective of providing incentives for cost minimizing behavior. However, the use of average cost may indicate a deterioration in performance, even though the utility responded to an exogenous change in a least cost manner. For example, assume two firms were identical in all respects except that one firm realized a sudden increase in load due to weather extremes. If both firms had been operating at the minimum point on their short run average cost curves, the one experiencing the increase in load would be pushed to the increasing segment of its short run average cost curve. This would be true even though the firm responded in a manner to meet the increase in a least cost way. If a monthly automatic fuel clause existed, the firm experiencing the load increase would then raise the fuel portion of its rate to recoup the shortfall accrued under the old rate, thus showing an increase in cents per KWH. The basic point is that a least cost response for a short period of time may give rise to increasing average costs <u>given</u> that plant (and purchases) are fixed in the short run. Furthermore, differences in the <u>timing</u> of rate relief can cause distortions among utilities.

Since average costs may vary with realized load, the use of an unadjusted average may be misleading. It may be possible to "normalize" for these effects across "comparable" firms, however, Vepco has not developed such a procedure at this time.

The central problem appears to be the choice of focusing not on the <u>cost of the utility to produce</u>, but on the <u>cost to the customer to acquire</u> electricity. In competitive markets where all costs are accounted for, these two costs are equal at the margin. However, under regulation, the lack of direct competition between firms in the market places the burden of ensuring this equality on the regulators. However, regulators focus not on market clearing price regulation per se, but on total revenue regulation.

In theory, the rates allowed by regulators already reflect the reasonable cost of production. Those costs that are deemed excessive or inapproriate will not be passed on to consumers, and will not be reflected in rates.

To a very large degree, changes in individual average revenue per KWH can vary drastically among "comparable" firms due to regulatory practices while having little or no impact on the average for the group. Some regulatory commissions will allow construction work in progress (CWIP) in rate base, while others will not. The treatment of CWIP can give rise to large differences in individual average revenues all other things being <u>equal</u>. This is also true with respect to the ratemaking treatment of other items such as cancelled plant, as well as the allowed return on equity. For these reasons comparisons of revenues per KWH are not solely comparisons of <u>firm</u> performance, but of <u>regulatory philosophy</u>, and changes in this philosophy as well.

Also of concern to Vepco is the ability to control for the differences cited above in the context of RCG's recommended program. The answer to these concerns would appear to be to place firms into "comparable" groups. The comparable groups would be delineated "with regard to their pertinent business environment characteristics." The problem with delineating comparable or similar groups of firms centers on defining the factors that make firms similar, as well as the context of similarity. Characteristics which would make firms similar with respect to investment risk in a portfolio, and those characteristics that make firms similar in a potential operating mode would, in general, differ. What is needed is a list of characteristics that when used to form similar groups will give rise to similar performance within a group and dissimilar performance among groups, not a list that could cause such differences.

Due to the above discussion these characteristics must include some measure of regulatory environment. Furthermore, past management decisions must be accounted for as these past decisions condition current and future responses. The consideration of past decisions is important because the movement to a future position in an optimal manner depends upon the starting point, which is a function of past decisions.

The position of RCG on this issue is that "previous poor or good decisions by management are reflected in a utility's performance measurement, which is consistent with designing an incentive program to promote good long term cost performance". RCG also states that accounting for past decisions would not affect a firms performance measurement either positively or negatively, and would lessen the potential for utilities to improve these performance characteristics that reflect their long term strategic decisions.

An incentive plan should be designed to reward or penalize a firm for its adjustments from the time the program was put into place, and should not reward or penalize a firm for decisions that were made in the past. There should be no ex-post considerations of past performance. Furthermore, it is not obvious how accounting for past decisions would lessen the incentive for future performance since firms must perform well relative to the other firms in its group.

As stated, of vital concern is the question of how the comparable groups will be formed. Once a list of characteristics has been drawn up, some mechanism of determining the boundary points of the groups based on these characteristics must be devised. RCG has stated that factor analysis, principal components, and cluster analysis could be used.

Factor analysis could be used to determine the relative importance of the characteristics but it does not determine where the boundary points between groups should be. Principal component analysis offers less promise since the principal components in general have no intuitive interpretation. Cluster analysis is sensitive to the norm chosen as well as the judgement of the analysts as to the meaning of resulting clusters. These techniques do not eliminate the need for subjective judgements.

The use of regression analysis fares no better since the comparison of actual to predicted performance is no more than a check on the explanatory power of the regression model. It should also be noted that if the regression model assumes normally distributed errors, then the ratio of actual to normalized performance has a Cauchy distribution, not a normal distribution as implied in the report.

If the comparable groups could be specified, RCG recommends computing two performance measures, a static measure and a dynamic measure. These are then transformed to the interval -1 to +1 and combined to produce the overall performance index denoted Relative Performance Index. The static index is a weighted average of past levels of revenue cents per KWH, while the dynamic index is the percentage change from year to year in the static index.

The weights used in the construction of the static index are a function of the consumers' discount rate. Putting aside the problems with actually measuring the value of what this discount rate is, it is not clear whether the <u>same</u> discount rate is used to calculate the weights in all years, or if the rate differs from year to year. If a <u>current</u> discount rate is used it would not seem appropriate to discount <u>past</u> values at a <u>current</u> rate since the current rate reflects the value of current and expected future opportunities lost due to today's decisions. Perhaps in forming the weights, the discount rate measured at the beginning of the time period over which the static measure is constructed should be used. This would give rise to the possibility that the dynamic measure may incorporate two distinct discount rates. Any possible anomalies this may cause are unknown at present.

The derivation of the weighting factors for the dynamic and static indexes, i.e. the values .667, .333, and the equation .5 + (Static Index Value/6) is unclear. On the surface these quantities appear arbitrary.

Once again it is necessary to reiterate a prior point; the plan must be cautious and aware of changes in regulatory practices. If firm A had the lowest static measure in period t, it could well have the highest measure in period t+1 due to a change in regulatory treatment such as being allowed CWIP in rate base. This sudden jump in its static measure could have nothing at all to do with its performance, but the jump in rates could alter the weights attached to both its static as well as dynamic index. This type of regulatory change is not uncommon.

An argument could be made for eliminating the static index altogether. This argument would be based on eliminating past management decisions as much as possible by relying totally on the dynamic measure. However, this places a large burden on the dynamic measure since equal absolute changes from an exogenous source do not translate into necessarily equal percentage changes. The possibility of these measures serving to give meaningful relative comparisons of utilities serving markets with different geographic and demographic characteristics is doubtful.

Several problems would seem to effect the possible implementation of the proposed plan. The static measure is based on a five year weighted moving average. If the proposal were to be implemented and the static index calculated based on the prior five years, then the utility would have its static index values influenced by management decisions for the next five years. In actuality, longer affects exist considering the long life of capital assets. Furthermore, the collection of the incentive dollars prior to the determination of any actual incentive payment would seem to be an injustice to the ratepayer. It deprives him of the use of his money for the period in question without proof that these collections are warranted.

In the implementation of the incentive plan, several concerns also need to be addressed regarding the eligibility of employees and the incentive payment. The funding would be determined based upon the top 1/2% of the utility's employees. Many companies implement incentive plans further down into their organizations and in Vepco's plan 1.3% of employees are eligible. Although the RCG proposal provides for the board of directors of the utility to determine participation, any increased participation above the 1/2% of employees used for the funding determination would require a lesser distribution per employee. In addition, the payout maximum of 35% of base salaries for the top 1/2% of employees and the example for Consolidated Edison appear on the surface to be adequate. However, this maximum payout is very unlikely since a utility would need both the highest static and dynamic measure and the incentive payout occurs only when the average performance of the comparable utility group is exceeded. Given these circumstances, the average annual incentive payment could be considerably below incentives paid the top executives in general industry as well as utilities. These concerns should be addressed especially considering the already low level of utility executive pay as a percent of general industry executive pay.

Comments On Additional Incentive Programs

Vepco agrees with RCG that the Automatic Rate Adjustment Mechanism is plagued with a number of problems that the Management Incentive Program was designed to circumvent (e.g. the input factor substitution problem), making it an undesirable alternative. Vepco also concurs with the argument that the Construction Cost Control Incentive Program has the undesirable attribute of affecting the return on equity which may give rise to more uncertainty, and hence, higher equity costs. Vepco also has some additional comments with respect to the Construction Cost Control Incentive Program (CCIP).

To implement the CCIP it is necessary to obtain an estimate of project specific rates of return. Given the problems of reaching a concensus of how a firms overall cost of equity should be determined, it seems doubtful that project specific returns could be calculated and agreed upon.

Another problem arises as to the definition of a legitimate change in scope. The triggering events listed in the footnote as they applied to the Alaska Natural Gas Transportation System case are very restrictive. It would seem that no matter how extensive a list of legitimate causes for a change in scope is, there will always be contested incidents which may well require litigation before FERC in order to resolve them.

Finally, Vepco would like to make five other comments with respect to the CCIP:

(1) The abandonment recovery percentage should be a lower bound on the recoverable expenses during the preliminary approval stage. There is no reason why all prudent expenditures should not be recovered.

(2) The formula for computing the actual capital costs (eq. (2) pg. 5.11) does not appear to allow for the compounding of AFUDC. Is this intentional?

(3) The equation for the one time rate base adjustment appears to be in error (eq. (6) pg 5.16).

(4) The plan focuses only on the cost of the project but does not consider scheduling changes based upon the need for the generation facility.

(5). Engineering is not always complete at the beginning of a project. Therefore, fine tuned cost estimates may not be available until the project is considerably underway.

****

MANAGEMENT INCENTIVE COMPENSATION PROGRAM

SUMMARY

1982

MANAGEMENT INCENTIVE COMPENSATION PROGRAM

I. OBJECTIVES

The program is designed to:

1. Place major emphasis on improving corporate performance.

2. Stimulate both individual and overall corporate performance in a manner that benefits both customers and stockholders.

3. Encourage individuals to set demanding and challenging goals and reward individuals for the risk assumed in setting such goals.

4. Provide individual rewards for outstanding contributions to supplement the rewards provided by the company's salary merit program.

5. Provide compensation rewards necessary to attract and retain highly competent and dedicated employees in the existing job market.

6. Provide compensation rewards for high performance without establishing the perpetual fixed corporate costs associated with salary increases and increases in fringe benefits.

II. ELIGIBILITY

Eligibility is initially limited to officers and managers who have established cost centers as of January 1, 1982.

An officer or manager newly included in the program should receive a thorough explanation by senior management of the performance goals established for his area of responsibility as outlined by the Incentive Compensation Performance Evaluation.

Incentive compensation will be prorated to reflect that portion of the performance year for which the new manager is responsible.

When a manager who is currently participating in the program is transferred or promoted both areas of responsibility should determine the individual's performance at the end of the program year.

III. OVERVIEW OF THE INCENTIVE COMPENSATION PROGRAM

The 1982 Management Incentive Compensation Program will be based upon goal accomplishments between January 1, and December 31, 1982. It is anticipated that the evaluation and subsequent decision as to whether compensation is rewarded under the 1982 program will occur approximately the beginning of the second quarter of 1983 (April). The Board of Directors will review and approve the 1982 program.

The Management Incentive Compensation will be based upon goal performance in two areas. These are shown below with their appropriate weight.

1. Corporate goals - 60%

2. Individual goals - 40%

The two components utilized to measure corporate goal accomplishment are common stock earnings per share and comparative customer cost per kwh. Individual goal performance percentage awarded will directly affect amount awarded under corporate goals.

Individual manager goals will be established through their senior executive and will be supportive and consistent with previously established corporate goals and their senior executive group goals. Management should emphasize setting a limited number of individual goals which have a significant impact on improving the performance of the company at each manager or executive level.

A Corporate Goal Committee has been appointed consisting of Messrs. S. C. Brown, Jr., J. I. Oatts, W. L. Proffitt, B. D. Johnson, J. T. Rhodes, and R. F. Hill, as Chairman. The function of this committee will be to review senior executive group goals to ensure that they are consistent with and supportive of both corporate goals and other senior executive group goals.

The maximum incentive compensation that will be paid under this program is twenty-five (25) percent of the executive's or manager's 1982 salary grade midpoint.

The calculation of an executive's or manager's incentive compensation will be based on an incentive percentage established by the President. This incentive percentage will be utilized in calculating the total incentive compensation percentage and will be applied to the executive's or manager's 1982 salary grade midpoint to determine the total dollar compensation.

This incentive percentage will vary based upon the individual's responsibilities within the company. The assumption is that the higher the individual's level of responsibility, the greater the impact his decisions have on corporate results, and the greater his reward should be under the Incentive Compensation Program.

The applicable incentive percentage will be finalized by the President during the goal evaluation process.

The Management Incentive Compensation Program is in addition to the existing salary merit program. Payment under this program will not be considered as earnings for the purpose of benefit programs other than the Employee Stock Ownership Plan (ESOP).

SDP/sl:0631C-14

IV. CORPORATE GOAL SETTING PROCEDURE AND PERFORMANCE EVALUATION METHODOLOGY

Early in the first quarter (January/February) of each year, the Board of Directors will review and approve annual corporate goals. There will be no payout under any portion of the plan if earnings per share are below $1.77.

Common stock earnings per share and customer cost per kwh goals within the corporate goals will be part of the Management Incentive Program and each will carry an equal thirty (30) percent weight. Corporate incentive awards will also directly depend on individual goal performance accomplishment.

1. Common stock earnings per share

   Incentive performance is evaluated by comparing the common stock earnings per share to the Incentive Compensation goal that was approved by the Board of Directors. For each one (1) percent that the actual earnings per share is higher than the Incentive Compensation goal, the Incentive Compensation will be increased one quarter (1/4) percent. For each one (1) percent that the actual earnings per share exceeds the corporate goal, the Incentive Compensation will be (1/3) percent. If the Incentive Compensation earnings goals is not achieved, then no compensation will be paid from this portion of the plan.

2. Customer cost per kwh

   Incentive performance is evaluated by determining the company's customer cost per kwh increase or decrease compared to the average increase or decrease of other comparable electric utility companies in 1982.

   For each one (1) percent that the company is below the comparable company average increase or above the decrease, the incentive compensation will be increased one quarter (1/4) percent. If the company's increase is greater than or decrease is less than that of the comparable company average, then there will be no compensation for this thirty (30) percent portion.

Performance Incentive Provision
Sample Calculation

Below is a sample calculation of the Performance Incentive Provision methodology. It is very important to note that this calculation is for expository purposes only. The data used do not match the time periods and some of the data are estimates. The rate base, common stock and retained earning figures were taken from the Settlement Agreement in Docket No. ER82-423-000 dated November 15, 1982. The sales figures for the municipalities and cooperatives were based on internal projections for 1982 as were the total system fuel expenses. The PROMOD run serving as the actual or PA was PROMOD study PS2DE700, a simulation of actual performance for the 12 months ended June 30, 1982 with level monthly forced outage rates. The PROMOD run representing the standard or PS was PROMOD study PS2DE701. Both of these PROMOD studies had been furnished to the staff and customers to indicate some level of sensitivity in the use of PROMOD.

In the actual application of the methodology, the factors would be based either on actual experience or be consistent with rates in effect. The sales figures and system fuel expense will be based on actual experience for the evaluation period. The two PROMOD runs will also use actual data, including, in the run to generate PA, actual generating unit performance for the appropriate periods. The rate base, common stock and retained earnings figures and the retention factors will be consistent with the rates in effect as of January 1 of the year during which the credit or charge will be effective. Absent final rates at that time, either by approved settlement or final order, the procedure specified on page 6 of the preceding document will be followed to determine the factors to be used in these formulas.

1. $PI = \dfrac{PA - PS}{PS}$

where PA = System fuel expense level for the PROMOD run using actual performance values.

PS = System fuel expense level for the PROMOD run using standard performance values.

PA = \$768,000,000 from PROMOD Study PS2DE700 (actual simulation, 12 months ended 6/30/82) with level forced outage rates.

PS = \$816,000,000 from PROMOD Study PS2DE701 (standard simulation)

$$PI = \frac{786,000,000 - 816,000,000}{816,000,000} = -.0588$$

2. $FC = \left(\frac{1}{1 + PI'} - 1\right) AF$

where FC = Change (savings or additional expense) in actual wholesale jurisdictional fuel expenses due to actual operation as opposed to operation at the standards.

PI' = Portion of PI (expressed as decimal) in excess of the dead band (.05) (expressed to four significant figures).

AF = Actual total wholesale jurisdictional fuel expenses for the period.

$PI' = -.05880 + .05 = -.00880$

$AF = \text{System fuel expense} \times \frac{\text{Jurisdictional sales}}{\text{System sales}}$

$= 630{,}800{,}682 \times \frac{4{,}794{,}242}{40{,}024{,}105}$

$= \$75{,}559{,}744$

$FC = \left(\frac{1}{1+(-.00880)} - 1\right) 75{,}559{,}744$

FC = \$670,829

3. $ROE^{*} = \frac{FC}{2} \times \frac{RF}{(e)RB} (10{,}000)$

where ROE^{*} = Change in the rate of return on equity (expressed in basis points).

FC = Change (savings or additional expense) in actual wholesale jurisdictional fuel expenses due to actual operation as opposed to operation at the standards.

RF = Wholesale jurisdictional retention factor (expressed as decimal).*

e = Common stock equity and retained earnings portion of the capital structure (expressed as a decimal).

RB = Wholesale jurisdictional rate base.

$$ROE^{*} = \frac{670,829}{2} \times \frac{.513582}{(.337)\ 403,183,000} (10,000)$$

12.68 basis points

*The retention factor used here is the average of the municipalities' retention factor (.496709) and the cooperatives' retention factor (.519932) weighted by their respective proportionate share of total wholesale jurisdictional rate base.

4. Allocation of FC* among classes

Municipalities allocation

$$= \frac{FC}{2} \times \frac{\text{Municipal Sales}}{\text{Jurisdictional Sales}}$$

$$= \frac{670,829}{2} \times \frac{1,290,017}{4,794,242}$$

$$= \$90,252$$

Cooperatives allocation

$$= \frac{FC}{2} \times \frac{\text{Cooperative Sales}}{\text{Jurisdictional Sales}}$$

$$= \frac{670,829}{2} \times \frac{3,504,225}{4,794,242}$$

$$= \$245,162$$

*FC within the 100 basis point maximum

Virginia Electric and Power Company
Docket No. ER82-423-000
Performance Incentive Provision

I. Scope

The Performance Incentive Provision will be implemented for a trial period of three years beginning in 1983. It is designed to compare the actual performance of the four nuclear generating units and twelve coal-fired generating units of Virginia Electric and Power Company (Vepco) against performance standards. Two runs of Vepco's production simulation model (PROMOD) will be used to conduct this comparison. The comparison will be expressed as the percent change (increase or decrease) in the fuel expense level due to the deviation of actual performance from the standards. Any deviation resulting in a change in the fuel expense level outside an accepted range (a dead band) will result in a charge or credit to the wholesale customers based on the proportionate change that would have been realized in actual fuel expenses.

The adjustment, either a credit or charge to the customers, will be translated into an equivalent change in the rate of return on equity that would have resulted at the time the adjustment was calculated. The maximum credit or charge will be limited to the value of 100 basis points equivalent change in the rate of return on equity.

The following paragraphs describe the method for comparing the standards and the actual performance, the application of the dead band, the method for translating the comparison into a charge or credit to the customers, the development of the standards and the schedule for implementation.

II. Methodology

A. Comparison of Actual Performance to Standards

The comparison of actual performance to the standards will be expressed as an index of relative performance. This comparison will reflect, as closely as possible, the change in the fuel expense level due to the deviation of actual performance of the subject generating units from their standards. PROMOD will be used to calculate this comparison. PROMOD utilizes inputs for each unit (e.g. fossil-fired units--forced, planned and scheduled outage rates, heat rate curves; nuclear units--run-time capacity factors) which can also be expressed in terms of the performance measures outlined in Section III.

On an annual basis, the fuel expense level based on actual performance will be compared to the fuel expense level based on performance at the standards. To compare the actual and standard performance, two runs of PROMOD will be made keeping all factors (load, fuel prices, etc.) the same, with the exception of the performance of the generating units specified in Section III. One run will set all performance measures at the actual values experienced during the applicable period. This run will simulate, as closely as practicable, the actual operations and fuel expenses for the evaluation period. The other run will set all performance measures at the standard values.

Both the actual and standard PROMOD runs will simulate a twelve-month period. The performance measures (both actual and standard values) will be the same for each month (with the exception of scheduled outages) and will be derived as follows:

Nuclear units:

<u>Actual value</u> - The average of twenty-four months of actual performance.

<u>Standard value</u> - The appropriate industry average based on twenty-four months of data, as described below in Section III.A.

Coal-fired units:

<u>Actual value</u> - The average of twelve months of actual performance.

<u>Standard value</u> - The appropriate twelve month standard, as described below in Section III.B.

The percentage difference between the two PROMOD runs will produce a "Performance Index" (PI) that represents the percent increase or decrease in the fuel expense level due to the deviation of actual performance from standard performance. The PI is defined as follows:

$$PI = \frac{PA - PS}{PS}$$

where PA = System fuel expense level for the PROMOD run using actual performance values.

PS = System fuel expense level for the PROMOD run using standard performance values.

A positive PI is indicative of additional fuel expenses relative to the standards. A negative PI is indicative of fuel savings relative to the standards.

B. Dead Band

The deviation of actual performance from the standards must produce an overall PI greater than +/- 5 percent or there will be no credit or charge to the customers. In other words, the PI derived using the formula on page 3 must indicate that PA was 5 percent greater than PS or 5 percent less than PS before a credit or charge will result.

C. Credit or Charge to the Customers

If the deviation of actual performance from the standards results in a PI in excess of the dead band, a credit or charge to the customers, in terms of actual fuel expenses, will be calculated. The relative effect the performance deviation would have had on the fuel expenses realized for the period will be calculated algebraically as follows:

$$FC = \left(\frac{1}{1 + PI'} - 1\right) AF$$

where FC = Change (savings or additional expense outside the dead band) in actual wholesale jurisdictional fuel expenses due to actual operation as opposed to operation at the standards.

PI' = Portion of PI (expressed as decimal) in excess of the dead band (+/-.05).

AF = Actual total wholesale jurisdictional fuel expenses for the period.

If the overall actual performance were better than the standards, the change in fuel expenses (FC) will be a positive value indicating a fuel savings. In other words, realized fuel expenses were lower than they would have been at the standard performance. If the overall actual performance is worse than the standards, FC will be a negative value representing the additional fuel expenses incurred because of the deviation of the actual performance from standard performance.

Vepco and the customers will share equally the change, either increase or decrease, in fuel expenses in excess of the dead band. Therefore, one-half of the savings or additional fuel expenses in excess of the dead band will either be credited or charged to Vepco's customers except that such credit or charge may not exceed (on an equivalent basis) the rate of return on equity limit described below. The credit or charge will be allocated to the municipalities and the cooperatives based on kilowatthour sales.

To determine the maximum total credit or charge that can be implemented and the equivalent change in the rate of return on equity, the change in actual fuel expenses due to a deviation of actual from standard performance (FC) will be translated to an adjustment to the rate of return on equity for the wholesale customers. The maximum credit or charge to the customers cannot exceed the value of 100 basis points as calculated below.

The formula for translating the change in actual fuel expenses to a change in the rate of return on equity, expressed in basis points, is as follows:

$$ROE^{*} = \frac{FC}{2} \quad x \quad \frac{RF}{(e)RB} \qquad (10,000)$$

where ROE^{*} = Change in the rate of return on equity (expressed in basis points).

FC = Change (savings or additional expense outside the dead band) in actual wholesale jurisdictional fuel expenses due to actual operation as opposed to operation at the standards (see page 4 for formulaic definition).

RF = Wholesale jurisdictional retention factor (expressed as decimal).

e = Common stock equity and retained earnings portion of the capital structure (expressed as a decimal).

RB = Wholesale jurisdictional rate base.

The formula for ROE^{*} above and the formula for FC on page 4 will be calculated based on the factors, including the methods for determining the wholesale jurisdictional allocations, consistent with the rates in effect as of January 1 of the year during which the credit or charge will be effective. If the rates have not been finalized at that time, either by approved settlement or final order, the staff, customers and Vepco will agree upon the factors to be used in these formulas. In the absence of approval or agreement by February 1, Vepco will use the relevant factors resulting in the rates then in effect subject to refund.

A sample calculation applying the Performance Incentive Provision methodology is found in Appendix A.

III. Standards

A. Nuclear

The nuclear standards will be derived from the most recent twenty-four month data, which are available at the time the standard is compared to actual performance, for all Westinghouse pressurized water reactors (except Yankee Rowe) reported in the Nuclear Regulatory Commission (NRC) Gray Book (NuReg-0020). As of November 15, 1982, there were twenty-eight units in this reference population.

From the NRC Gray Book data, the capacity factor (CF) standard for Vepco's two North Anna nuclear units will be computed as follows:

CF Standard = Sum of the net generation (kilowatt-hours) for each of the units in the population divided by the sum of the products of the maximum dependable capacity and the period hours* for each of the units in the population

*The period hours of those units entering commercial operation during the twenty-four months will be computed starting with the date of commercial operation.

The capacity factor standard for Vepco's two Surry nuclear units will be computed using the basic formula stated above with two modifications. The modifications are attempts to recognize the improved reliability from the replacement of the steam generators at the Surry units. First, the period hours for each unit in the NRC Gray Book population experiencing a steam generator replacement outage will be modified by subtracting the outage or equivalent outage hours due to that replacement minus 1,080 hours (45 days). Second, the adjusted national average capacity factor will then be further modified by adding 1 percentage point.

B. Coal-fired Units

The standards for each coal-fired unit will be the equivalent availability factor and heat rate derived for each unit considering its historical performance, inherent limitations, fuel supply, potential improvement and planned maintenance. The performance standards for the coal-fired units will be set for each twelve month period using this general approach. Vepco will submit the proposed standards to the Commission's staff and the customers no later than November 1 of the year preceding the one during which the standards will be applied. By the following April 30th the staff, customers and Vepco will agree upon the coal-fired standards for that year. As provided in Section IV below, absent agreement the standards issue and any other issue unresolved will be set for hearing.

The performance standards for 1983 are as follows:

Unit	Operating Heat Rate*	Equivalent Availability
Bremo 3	12,379 Btu/kWh	72.3%
Bremo 4	9,944	77.5
Chesterfield 4	10,648	80.2
Portsmouth 3	10,745	77.4
Portsmouth 4	10,500	75.2
Possum Pt. 3	11,294	72.4
Possum Pt. 4	10,577	77.2
Chesterfield 5	10,210	72.8
Chesterfield 6	10,300	50.4
Mt. Storm 1	10,210	60.3
Mt. Storm 2	10,210	61.5
Mt. Storm 3	10,962	67.4

*The performance standard used in the PROMOD runs to determine PI will actually be the heat rate curves based on this list of operating heat rates. These operating heat rates are based on certain load factors for each unit. If the load factors resulting from the dispatch of the units change, another operating heat rate value will result. That operating heat rate, however, will be considered consistent with the performance standard if it is on the standard heat rate curve based on the operating heat rates listed for each unit.

C. Modifying Events

On a case-by-case basis, Vepco may request consideration of an adjustment to the actual performance because of a major outage or deration (a modifying event). In order for an outage or deration to qualify as a modifying event, Vepco must meet the burden of showing that such outage or deration was not caused by its failure, at the time of the outage or prior thereto, to exercise prudent utility practices, which will be defined as follows:

> Any of the practices, methods, and acts engaged in or accepted by a significant portion of the electric utility industry at the time the decision was made, or any of the practices, methods, and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, would have been expected to accomplish the desired result at a reasonable cost consistent with reasonable reliability, safety, expedition and protection of the environment. A prudent utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes a number of possible practices, methods, or acts.

Vepco may request consideration of an outage or continuous deration which is at least the equivalent of 2,920 unit outage hours (4 months) on the nuclear units or 1,460 unit outage hours (2 months) on the coal-fired units. As soon as Vepco has determined that it has experienced a possible modifying event, it will notify the staff and customers.

After all parties have agreed or, absent an agreement, the Commission has concluded that Vepco has experienced a modifying event, an adjustment for the period during which the modifying event occurs will be made as follows:

1. Nuclear units - The capacity factor for the Vepco unit(s) experiencing a modifying event (the affected unit(s)) will be adjusted by subtracting from the period hours the outage or equivalent outage hours due to the modifying event(s). The period hours for any of the units used to compute the standard for the affected unit will also be adjusted by subtracting outage or equivalent outage hours attributable to essentially the same kind of modifying event(s). In addition, the staff or the customers may request consideration of an adjustment to the actual performance of the units used to compute the standard for the affected unit because of a modifying event. To qualify, each outage or continuous deration must be at least the equivalent of 2,920 unit outage hours (4 months) and the staff and/or the customers must meet the burden of showing that such outage or deration was not caused by the failure of the utility, at the time of the outage or prior thereto, to exercise prudent utility practices, as defined above. After all parties have agreed or, absent an agreement, the Commission has concluded that any unit used to compute the standard for the affected unit has experienced a modifying event, the period hours for any of the units used to

compute the standard for the affected unit will be adjusted by subtracting outage or equivalent outage hours attributable to each modifying event. In addition, both of these adjustments will continue for the evaluation period during which Vepco's actual performance was affected by its modifying event. By agreement of the parties or, absent agreement, by order of the Commission, it shall be determined whether it is appropriate to reduce the length of the modifying event for both Vepco's unit and the standard unit(s) to reflect other work done during the course of the modifying event outage.

2. Coal-fired units - The actual forced outage rate experienced by the affected unit will be modified by decreasing the outage or equivalent outage hours by those attributable to the modifying event. As stated above, by agreement of the parties or, absent agreement, by order of the Commission, it shall be determined whether it is appropriate to reduce the length of the modifying event to reflect other work done during the course of the modifying event outage. The actual heat rate for the affected unit will be decreased by the amount of the deviation attributable to the modifying event.

All parties and staff shall make every reasonable effort to resolve disputes concerning modifying events through negotiations.

IV. Implementation

The Performance Incentive Provision will be implemented for a trial period of three years beginning on January 1,1983. Unless the staff, the customers and Vepco all agree, no modifications to the program can become effective until January 1, 1984 or thereafter.

The first period of actual performance to be compared to the standards will be the twelve month period ending December 31, 1983 for the coal-fired units and the twenty-four month period ending December 31, 1983 for the nuclear units. Every year thereafter the preceding twelve month period for the coal- fired units and the preceding twenty-four month period for the nuclear units will be compared to the appropriate standards.

The implementation schedule for the provision will be the same each year. By February 28, Vepco will submit to the staff and customers information concerning the previous twelve or twenty-four month period of performance of the units and the proposed credit or charge. For example, Vepco will submit this information on February 28, 1984 for the twelve month period ending December 31, 1983 for the coal-fired units and for the twenty-four month period ending December 31, 1983 for the nuclear units.

The information submitted by Vepco before February 28 will include:

1. The actual performance statistics for the applicable year.

2. The standards for that year.
3. The realized total system and jurisdictional fuel expenses for that year.
4. The workpapers setting forth the formulas and the application of the formulas to the actual data to derive the credit or charge.
5. Vepco's showing that it has experienced a modifying event and the appropriate adjustment derived therefrom.
6. A description of any changes in the PROMOD model including a change in relative fuel prices or PROMOD coding.

Upon request, the staff or customers will also be furnished with the inputs to PROMOD used to generate PA and PS and any other relevant data requested.

By April 30, the staff, customers and Vepco will resolve any issues regarding all information previously submitted by Vepco (including the applicable coal-fired standards for the year) and will agree to any appropriate credit or charge. If necessary, any unresolved issues will be set for hearing.

On July 1 a credit or charge, either as agreed upon or, absent agreement, as proposed by Vepco and filed with the Commission, will take effect. The credit or charge will be reflected as an adjustment charge to base rates and will be collected or refunded over the succeeding twelve months based on projected sales. In the event that the staff, customers and Vepco have not agreed to the credit or charge, it will be collected for the period subject to adjustment. When the parties agree or the Commission orders a credit or charge, the credit or charge for the year immediately following the agreement or order will be made to reflect any under or overcollections.

The rider will be terminated at any time during the twelve months when the full credit or charge has been refunded or collected. At the end of the twelve months, if the full credit or charge has not been refunded or collected due to differences in projected sales and actual sales, that amount of short fall in the credit or undercollection in the charge will carry over to the next period. A customer who ceases to be a Vepco customer any time during the twelve month period will be refunded or assessed its share of the outstanding credit or charge for the year.

A detailed account will be kept of all under and overcollections due to any cause. At the end of the three-year implementation period, a detailed review of the Performance Incentive Provision shall be conducted. Even if the Performance Incentive Provision should terminate, there will continue to be a credit or charge to the customers until all under or overcollected amounts have been reconciled.

Wisconsin Electric POWER COMPANY
231 W. MICHIGAN, P.O. BOX 2046 MILWAUKEE, WI 53201

April 11, 1983

Dr. Bernard Tenenbaum
Acting Chief
Economic Analysis Branch
Office of Regulatory Analysis
Federal Energy Regulatory Commission
Washington, D.C. 20416

Dear Bernie:

Recently you provided me a copy of the Resource Consulting Group report concerning Incentive Regulation in the Electric Utility Industry. I appreciate that and again would like to express my gratitude to you.

We have reviewed this report extensively within the Company and have prepared a summary and evaluation of it for our senior management. I have attached a copy of it for your information.

I have read both the NERA report and the one prepared by Joe Schaefer of our company. Frankly, I like ours better. It seems to us that perhaps more value should be given to the RCG report than NERA is prepared to give. Although I agree with the NERA findings pertaining to the comparison groupings, we should not lose sight of the key element of their proposal: to place into the regulatory process an incentive system which will motivate and reward those who can bring about significant productivity improvements. This practical recognition is a breath of fresh air in what heretofore has been an emphasis on mechanistic approaches to mandating improvement rather than motivating it. There is no question that pursuing such a program, regardless of the form of measurement, will take much additional effort; however, it is worth pursuing.

I trust you will conclude that overall the report is positive in regard to making the effort to develop acceptable, meaningful, and practical incentive schemes toward achieving our mutual objectives.

Sincerely,

Dick

Richard A. Abdoo/cmt
Vice President
Corporate Planning

Attachment

February 10, 1983

Productivity Policy
Committee:

Review of
"Incentive Regulation in
the Electric Utility Industry"
The Resource Consulting Group (RCG)
October 15, 1982

By memo of December 20, 1982, Mr. Ricci requested my review of this proposal to FERC by the RCG.

This study was conducted under contract to FERC by the Resources Consulting Group (RCG) in response to the general concern about utility performance and the proliferation of programs being proposed to improve it. RCG proposes an incentive regulation system based on aggregate cost performance (revenue per KWH). Acceptable performance would be determined by comparison of individual company performance against the performance of a group of utilities with similar characteristics. Better than average performance would be rewarded by rate-payer funded bonuses to management. The program would be administered by state regulatory commissions in cooperation with FERC. The RCG recommends this program because it concludes it will more effectively promote cost minimization than does the traditional regulatory process.

This review and summary addresses the following questions considered by RCG in proposing to FERC there be an incentive regulation process for investor-owned electric utilities.

The proposal made by RCG would operate in the following environment:

- Participation by utilities would be voluntary. If a utility chose not to participate, it would still be required to submit reports and other data required to administer the system that would apply to voluntary participants.

- Participation and administration of the system by state PSC's would be necessary because it would be too burdensome at the federal level and because application to FERC - only jurisdiction would have only minimal impact.

- The required rate of return would be established generically by FERC.

In developing this summary, I have studied the following:

- Incentive Regulation in the Electric Utility Industry, Resource Consulting Group, October 15, 1982.

- FERC Study on Incentive Regulation, EEI (Rate Research Committee), January 7, 1983.

- Draft Comments of ERG Productivity Subcommittee, January 1-, 1983.

- Proposed Comments to FERC by ERG, January 20, 1983.

- "Price Index Components for Utility Rate Adjustments", William A. Gale, PUF, April 15, 1982.

- "Productivity Incentive Clauses and Rate Adjustments for Inflation", William F. Baumol, PUF, July 22, 1982.

The RCG asks five basic questions. My summary will state the question, provide the RCG response, and provide my evaluation;

- "Which aspect of utility operations should a program be directed at improving?" RCG recommends that the target is the firm's aggregate cost performance. Cost is defined as all expenses required for the generation, transmission and distribution of electricity; the cost of fixed capital inputs; and the cost to consumers for lost electrical service. In this definition we encounter the first problem with the RCG proposal: determining the cost of lost service. The RCG recognizes this problem in the following statement:

> "Because of the complexity of the adjustment described above (determining the quantity of lost service) FERC may choose to implement an unadjusted cost measure...A relatively simple reporting format could be developed to provide these data on an annual basis."

I do not believe the "simple format" will do the job. If the problems were easily solved, they would have been by now. More importantly, the dollar/cost impact, except in the case of a major emergency, would be negligible and not worth "chasing". Therefore, I would propose annual stipulation, annual customer survey data, or the like to dispose of this issue.

- "How should performance be measured?" RCG recommends an aggregate cost model defined as follows:

$$\frac{\text{Total Revenues from Electricity Sales}}{\text{Total KWH Sales to Wholesale and Retail Customers + Losses.}}$$

In effect, the measure is equivalent to total expenses including return on capital and income taxes. Their key point here is that the aggregate cost measure must include capital effects so as to not motivate capital substitution for other inputs. RCG recommends this measure over TFP, with which I agree. You may recall in our prefiled testimony for the Prehearing Conference on ER-16, May 21, 1982, we had proposed a total revenue per KWH sales performance indicator.

As a part of the measurement question, there is the matter of the length of the measurement period. RCG recommends a period of not less than three years or more than five, with a weighting process which gives the most recent year a 25% weight. The length and weighting recommendation are both subjective. We have tended to use a ten year period wherever possible. I believe this desirable because of the influence of capital additions on costs. As you are aware capital additions, most significantly power plant additions, have had:

a) a definite cycle
b) the greatest influence on costs and productivity.

Therefore, to use a short period would tend to unduly reward and penalize just prior to or right after, respectively, a major plant addition. These aberrations in rewards and penalties would not necessarily be relatable to managerial performance. They would unnecessarily destabilize the incentive program which would be self-defeating.

-- "How should performance be evaluated?" RCG recommends a system to relate individual utility performance versus a group with similar characteristics:

- Total generating capacity
- Average load factor
- Historical and forecast load growth
- Percent sales to commercial and residential customers
- Stringency of environmental requirements
- State and local tax burdens

RCG suggests using automated regression analysis to assist in the grouping process together with a panel of experts. My evaluation of this proposal is that it has been demonstrated sufficiently now that inter-company comparisons are not valid for rate setting purposes, e.g., the Red Flag studies. The inter-company performance comparison aspect in my judgment is the single most deficient aspect of the RCG proposal and is sufficient grounds for going no further. The deficiencies of the grouping process are explored in depth in the NERA paper of January 20, 1983.

The RGC proposes, as a less preferred alternate, an indexing process. This process uses an automatic rate adjustment mechanism linked to price changes in the utilities production inputs, as measured by external price indexes. The external price indexes would cover fuel, labor, other materials and supplies, and purchased power. Capital costs are not included. Such indexes would be, respectively: average of spot prices for the coal districts supplying the utilities in a region, regional labor cost index, producer price index, and the average price per KWH paid by a group of utilities for purchased power on a monthly or quarterly basis. It suffers from four shortcomings:

- there is no all-inclusive index for utility operations
- interactivity of inputs is ignored
- productivity in the base year is assumed to be acceptable
- lack of acceptable method for indexing capital costs

I believe this approach could be pursued with a greater probability of success than the grouping technique because it is not dependent on the performance of other firms. The Fortnightly articles give some aid in this, but not much. In Gale's article the testing process is quite extensive. In Baumol's paper, the framework is theoretically sound; but practically of little value.

- "How should the incentive program operate?" RCG recommends the focus of the incentive mechanism should be on management compensation. The source of funds would be revenues based on the firm's superior performance. The rationale is three-fold:

- The firm's management will be the group to implement any performance improvements. The incentive effect on earnings will not have the same impact.

- The program would be less expensive than an earnings-directed program. The customers would be able to reap greater benefit at lower cost.

- An incentive program that affects management compensation will have a negligible effect on the cost of capital.

The amount of incentive compensation would be set at 35% of the sum of the base salaries for the top 1/2% of all employes in the firm. For Wisconsin Electric, this would cover all officers and 11 additional executives, for a total of 27 executive employes. Thirty-five percent of these salaries would be in excess of $500 thousand. The average amount would be at least $18,825.

The form of these rewards would be in direct payments through systems of "long-term performance attainment awards" which are tied to the performance of the company, not to its stock. The plans tend to be long run in nature as a means to encourage executives to focus on what is best for the company in the long-run. Performance measurement periods of most of these programs vary between three to five years. Participation is limited because only employes with fairly high positions in the company are assumed to have a major impact on corporate performance.

I believe the focus recommended by RCG is preferable for the reasons given above. RCG recommends the following administrative guidelines which are also proper and reasonable:

- Structure it so there is reasonable probability of achieving a reward.

- The incentive reward should not exceed the gain in performance.

- The system should encourage a firm to undertake improvements.

- Increase the share of economic benefits to management for performance improvements at the margin (over time).

- Do not include prospective dollar penalties other than failure to earn a reward.

- The distribution of rewards would be the sole prerogative of the firm.

- "How should the incentive program account for events beyond management's control?" RCG recommends under these conditions there be no reward or penalty for such occurrences. It also recommends regulators may have to make "special discretionary adjustments" in administering the program. This is perhaps the only method; however, it is possible such issues could generate lengthy public hearings and could erode the program.

Conclusions and Recommendations

- The proposal by RCG has two aspects which are supportable;

  1) The use of an aggregate cost measure by which to measure utility performance.

  2) The use of rewards directed at management compensation to provide the incentives for improved future performance.

- The RCG proposal has several drawbacks which are significant;

  1) It recommends a quality measurement which is illusive and potentially not worth the cost to administer.

  2) The proposal uses a grouping technique which calls for intercompany comparisons based on factors previously considered by NARUC, NRRI, and NERA. The grouping technique and the factors used have been discredited. To my knowledge this approach is not being seriously proposed at this time.

- The RCG study made mention of an incentive system using aggregate cost measures being developed by the Utah Power and Light Co. and the Utah

Public Service Commission. Since Utah Power and Light is virtually the only electric utility in Utah, I believe this is worth pursuing. Further information is anticipated. This will be pursued as a possible contribution to any system which may be appropriate to develop.

- The overall program could be politically unacceptable, no matter how cost-effective.

J L Schaefer

JLS/jmu

cc: Mr. R. G. Chase

State of Wisconsin \ PUBLIC SERVICE COMMISSION

February 4, 1983

STANLEY YORK, CHAIRM
WILLIE J. NUNNERY, COMMISSION
BRANKO TERZIC, COMMISSION
4802 SHEBOYGAN AVE
P.O. BOX 7
MADISON, WISCONSIN 53
(608) 266-2

Dr. Bernard Tenenbaum, Acting Chief
Economic Analysis Branch
Office of Regulatory Analysis
Federal Energy Regulatory Commission
Washington, D. C. 20426

File No.

Re: Comments on Report of the Resources Consulting Group

Dear Dr. Tenenbaum:

The RCG report on productivity measurement and incentive ratemaking is, in my opinion, a responsible effort, and a valuable addition to existing literature on the subject. A sincere effort was obviously made to develop a practical measurement tool and a practical means for utilizing it while at the same time making accommodations for some of its basic weaknesses.

The RCG approach is to use a simple ratio (total revenues from electricity sales)/(total kWh sales to retail and wholesale customers plus losses). The report indicates that comparisons would then be made among utilities in "homogeneous groups." This approach is indeed straightforward and it does provide a "number" to be used for comparing utilities' performance and productivity.

I do have serious reservations about the ratio being used as <u>the</u> indicator rather than <u>an</u> indicator, particularly for inter-utility comparisons. The following are some of these concerns:

1. As with the total factor productivity ratio, the relationship would be expected to vary considerably from year to year and hence the regulatory interest should be in the trended result over a period of years rather than the specific result for a given year. This may create problems when the ratio is used for incentive ratemaking. The RCG report discusses this problem and suggests a method for resolving it. Whether the solution adequately addresses this problem is not yet apparent.

2. The report addresses certain factors which may have an important impact on the RCG ratio or its application but which are largely beyond the control of utility management. Some of these are the following:

    a. The impact of fluctuations in the nation's economy on the operating results of the specific utility.

This will vary from region to region, both inter-state and intra-state, both as to the extent and duration of the impact. For example, because of the heavy industrial load in eastern Wisconsin our state is expected to lag the nation as a whole in recovery from the present recession. This will similarly impact the utilities serving this area.

b. The differing effects of economic regulation under the different regulatory agencies involved.

c. Past decisions by utility management having long-term results. This includes a host of decisions and actions dealing, for example, with existing generation mix and reserve level. RCG recognizes that this problem exists and must be considered.

d. The cost of fuel (including transportation costs) for generation which in turn is related to the proximity of generation to fuel sources and the alternative transportation means available.

e. System load characteristics as determined by the specific composition of customer loads.

f. Shared ownership of major generating plants.

The consultant suggests that the ratio would be used for comparative purposes within "homogeneous groups" of utilities. The foregoing paragraph deals with only a few of the differences in characteristics and conditions under which utilities operate, pointing to the difficulty of achieving such homogenous groups.

Use of the ratio for incentive ratemaking has the potential for giving counterproductive signals with respect to the consumers' best interests. For example, application of the ratio would seem to encourage short-term benefits at the expense of longer-term benefits which may be more advantageous to the utility's customers. For example, this would tend to discourage providing additional hydroelectric capacity since the fixed costs associated with such projects would be relatively high, and only over the very long term would the effects of the lower variable costs operate to produce net present worth benefits when compared with other generation supply alternatives. Similarly, incentive-type ratemaking could encourage delaying needed additional generation, transmission and distribution capacity thus potentially leading to eventual reductions in service reliability. The impacts of such actions may not be felt until years leter. Current measurements of service adequacy as suggested by RCG would not be particularly significant because the impacts might not occur until much later. Risks involving potential consumer costs from service outages may be taken by the utility to achieve interim benefits offered by incentive ratemaking.

Further, implementation of incentive ratemaking utilizing the suggested ratio would be a disincentive to participating in regulatory efforts designed to encourage energy conservation (reduced kilowatt hour sales). This range of issues is being addressed in our Advance Plan proceeding which is scheduled for Commission decision in mid to late February. If the determination sheds any light on this problem, we will send you some information on it.

It is for all of the above reasons that I feel the RCG ratio should not be the only indicator used in looking at utility performance but that much more comprehensive reviews are required. This Commission is in the process of studying development of a system or systems of performance indicators, which material would be tabulated and presented during each rate proceeding for the benefit of the Commission. Such ratios would be expected to "red-flag" situations where the performance of a given utility appears to be abnormal, thus pointing to the need for further study and evaluation to determine whether the particular situation does or does not reflect poor performance or productivity. Any such system of indicators should, of course, include an appraisal of generating plant performance and efficiency since the costs associated with power production represent such a large part of each utility's revenue requirement.

Utilities in Wisconsin and probably in most jurisdictions have generally been unsuccessful in actually realizing the authorized return on equity. This suggests that there already is a major economic incentive for utilities to operate efficiently.

The RCG proposal for using the incentive earned under the plan as incentive compensation for utility managers is interesting. I have two concerns here. First, precautions would have to be provided so that management would not be rewarded for an improvement in the ratio which resulted, for example, from an improvement in general economic conditions or more favorable tax treatment without any special actions by management. Second, precautions would also be necessary to prevent the situation occurring where management would abuse the system such as by simply deferring certain expenditures for one or several years to achieve a one-time incentive reward. This could involve taking risks with service reliability such as by operating with lower generating reserves than otherwise considered necessary. This would be more likely to occur in a situation where no actual penalties would be assessed.

My comments have generally been critical of the RCG proposal and should rightly be considered so if it is intended that the RCG method would simply be applied to statistical data taken from filed utility reports without further in-depth analysis. The proposal represents an interesting approach and perhaps with some trial experience and careful analysis the proposed method or some variation thereof could be developed for use as an effective tool. At this point the major problem would seem to be that of developing the homogeneous groups of utilities because of the many significant differences between utilities and the conditions under which they operate.

I trust the foregoing comments will be helpful. Thank you for sharing it with us.

Sincerely,

Stanley York
Chairman

SY:CFR:kjn