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INCENTIVE REGULATION IN THE ELECTRIC UTILITY INDUSTRY: VOLUME I

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Introduction

The U.S. electric utility industry operates in a business environment that provides fewer incentives for efficient (i.e., cost-minimizing) performance than non-regulated, competitive markets. Several factors contribute to this situation. First, as a result of the regulatory process, firms are limited to earning a "reasonable" rate of return. Thus, even when firms increase their production efficiency (i.e., reduce their short- and long-run costs of meeting demand by combining production inputs in a more optimal manner), they are prevented from receiving the additional profits that would be earned in a non-regulated, competitive market. At the same time, regulation will likely allow less-efficient firms price increases that could not be obtained in a competitive market. Also, at least in the short run, electric utility firms have a relatively fixed market and their customers have limited ability to reduce or increase electricity consumption in response to price changes; this further shields these firms from the economic gains or losses that could be associated with improvements or deteriorations in their efficiency.

In this business environment, regulators have traditionally relied on regulatory lag* and a scrutiny of costs and management procedures to encourage the efficient management of utility firms. However, in recent years, high inflation in essentially all inputs to utilities' operations has led to considerably briefer intervals between rate cases,

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* Regulatory lag refers to the period between rate adjustments; during this period, a utility's prices (at least for some components of its cost of service) remain fixed. An improvement or deterioration in production performance during this period translates into changes in utility profits, which may exceed or fall below the return level embedded in the firm's rates. Because the firm's earnings are placed at risk during the period of regulatory lag, it is generally assumed that regulatory lag creates an incentive for utilities to operate efficiently.

thus reducing the potential effectiveness of regulatory lag as an incentive for efficient operations. In addition, the general trend of increasing costs has made it difficult for regulators to monitor and evaluate the cost performance of utilities. Indeed, the introduction of automatic rate adjustment programs (for example, fuel cost adjustment clauses) has further weakened the potential incentive effect of regulatory lag. The problems attendant to the rapidly increasing costs faced by utilities in recent years, coupled with the deteriorating financial condition of many firms in the industry, have increased regulators' and other observers' concern that utilities may not be achieving the desired levels of production efficiency.

Faced with these circumstances, innovative regulators have begun efforts to improve production efficiency in the utility industry. Overall, these efforts are directed at reducing the rate of increases in utility rates and encouraging the provision of electrical service at the lowest possible cost. These performance improvement programs have taken widely-varying forms. For example, several state utility commissions have adopted programs aimed at increasing generating unit operating efficiency and availability, or at controlling one or more expense accounts. In addition, several state commissions have implemented incentive programs to control the cost of generating plant construction. Each of these programs includes some procedure for rewarding and, in some instances, penalizing a firm for superior and inferior performance, respectively.

At the same time, utilities have also begun to implement programs designed to improve their performance. Typically, these programs take the form of incentive compensation plans that provide rewards for selected managers on the basis of their performance with respect to corporate and individual performance targets. These programs have been implemented from within the firms and center on improving the utility's performance with regard to one or more measures that are important to both shareholders and utility customers. For example, some firms have initiated programs that are based on the achievement of rate-of-return on equity or earnings targets. Other incentive programs are geared toward improving generating unit performance or reducing electricity rates relative to those of other firms.

Although both regulators and utility managers have taken steps to strengthen the electric utility industry's incentives for superior production performance, there is no concensus over what form a program should take to enhance performance and minimize utilities' overall cost of service. Indeed, it is possible that some programs which are focused on improving performance with regard to a narrowly defined measure of operating efficiency (e.g., generating unit availability) may actually lead to increases in a utility's overall cost of service.

In response to the general concern about utility production performance and faced with a proliferation of programs for improving performance, the Federal Energy Regulatory Commission (FERC) has undertaken an examination of incentive regulation programs designed to encourage improved production performance in the electric utility industry. However it is achieved, 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 firms.

To assist in this effort, FERC retained Resource Consulting Group, Inc. (RCG), to conduct a comprehensive analysis of the issues involved in formulating an incentive regulation program and to develop and evaluate an incentive regulation program to be considered for implementation by FERC.* In this report, RCG presents its findings regarding these areas of inquiry.

In conducting this study, we structured our analysis with the primary objective of designing an incentive regulation program that would encourage the provision of electrical service to customers at the lowest possible price, consistent with a satisfactory level of service quality. To facilitate structuring such a program, we identified and analyzed a set of fundamental issues that must be considered in designing and implementing an incentive regulation program. These issues include:

- At what aspect of utility performance should an incentive regulation program be focused?

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* We were assisted by our sub-contractors, Drs. Ronald Ehrenberg, Jerome Hass, and Robert Smiley of Cornell University.

- How should performance be measured and evaluated in the context of an incentive regulation program?

- How should the economic outcomes (i.e., reductions or increases in the firm's cost of service) or the performance results achieved under an incentive program be shared between a utility and its ratepayers?

- Should the sharing mechanism in an incentive program include both a reward and a penalty?

- How should an incentive mechanism be structured to reward or penalize a firm for superior or inferior performance (e.g., should a reward affect allowed return, rate levels, or management compensation)?

- How should rewards or penalties to a firm be distributed between management and shareholders?

- How should the incentive regulation program adjust for factors or events that are beyond a firm's control in rendering rewards or penalties for superior or inferior performance?

An additional issue that underlies the design of an incentive regulation program is whether the program is suitable for implementation only by FERC or, if the program is to be effective, must it be implemented by both FERC and state commissions? In general, because FERC regulates only a rather small fraction of a firm's revenues, an incentive program will need to be applied under a cooperative effort by both FERC and state commissions to be effective in promoting the minimization of utility costs in providing electric service to ratepayers.

To analyze these issues and provide a basis for formulating an incentive regulation program that would most effectively promote utility cost minimization, we conducted reviews and evaluations of the following:

- A number of incentive regulation programs that have been implemented by regulators in the electric utility industry and other regulated industries,

- Several management incentive compensation programs that have been implemented by electric utilities to encourage better performance in their firms,

- Incentive programs that utility industry analysts and other persons concerned with the industry's performance have proposed, but that have not been implemented,

- Alternative approaches for measuring and evaluating an electric utility's performance as a basis for incentive regulation; this analysis included a detailed review and evaluation of total factor productivity indexes and other aggregate performance measures, and

- Other performance measures and incentive mechanisms which are potential options for constructing a comprehensive incentive regulation program; these were analyzed on both a qualitative and quantitative basis.

On the basis of our analysis, we have formulated, and recommend to FERC, a comprehensive incentive regulation program designed to encourage utilities to maintain the lowest possible rates to their consumers. Specifically, this program is aimed at encouraging a utility to reduce the growth and level of its electricity rates relative to those of other firms. The incentive reward mechanism is designed to affect management compensation, and thus directly affects the agents of the firm who must ultimately accomplish any improvements in its performance. The concept underlying this program is to simulate a sense of price competition among comparable firms, as though the firms operated in a competitive, non-regulated market. At the same time, the sense of price competition is achieved without placing the firms' earnings at risk, thus preserving a principal advantage of the regulated, protected monopoly environment in which utilities operate: low cost of capital. We support this program because it will:

- More strongly promote cost minimization than does the traditional regulatory process

- Promote cost minimization without distorting signals to the firm to combine its productive resources efficiently in both the short- and long-run

- Transfer to ratepayers the greatest possible share of the economic benefits associated with performance improvements.

To be most effective, this program will require cooperation by both the FERC and state regulatory commissions. Moreover, utility managers and boards of directors must be receptive to the use of ratepayer-funded incentive compensation programs.

In addition to our recommended incentive program, we delineate two incentive programs that may be substituted for, or be complementary to, our recommended program.

Although we strongly support our recommended program, these two additional programs have substantial merit and, on the basis of our analysis of them, we recommend that these programs be considered for implementation. The first program is a construction cost control incentive program. It links both an incentive rate-of-return mechanism and an incentive compensation plan for construction program managers to a utility's cost performance in constructing major projects. This program could be implemented in conjunction with our preferred program. The second program incorporates an automatic rate adjustment mechanism linked to price changes in a utility's production inputs, as measured by external price indexes. This program could be implemented as a substitute for our preferred program.

In Chapters 1, 2, and 3, we present our analyses of the issues that should be addressed in formulating an incentive regulation program. We describe our recommended program in Chapter 4. In addition, in Chapter 5, we describe and evaluate the two additional programs which FERC might consider for implementation. Finally, in the appendixes, we present analyses supporting our recommended programs and critical reviews of existing or proposed incentive regulation programs.

1 A FRAMEWORK FOR DESIGNING AN INCENTIVE REGULATION PROGRAM

Designing an incentive regulation program requires consideration of a complex set of issues and alternative approaches to resolving these issues. These issues deal with specific design features of a program and broadly include such questions as:

- Which aspect of utility operations should a program be directed at improving?
- How should performance with respect to this aspect of operations be measured?
- How should individual firm performance be evaluated as a basis for granting incentive rewards or penalties?
- How should incentive rewards or penalties be granted to a firm?
- What should be the amount of rewards of penalties that a firm receives as a result of its performance?

These issues may be resolved in a variety of different ways. The different possible resolutions of these issues can lead to very different incentive programs that, as a result, can have markedly different effects on firm operations and the eventual benefit to consumers from an incentive program. As a simple illustration, consider the first question. An incentive program may be focused at improving overall cost performance for the firm or at improving any of several subaggregate aspects of firm performance such as generating unit availability, management of operating and maintenance expense, or management of fuel and purchased power expense. Depending upon the selection of a program focus from among such options, the overall design and ultimate effectiveness of an incentive program may vary widely. For example, the selection of aggregate cost performance as a program focus would imply different procedures for measuring and evaluating performance from those implied for a subaggregate focus such as generating unit availability.

To assist in analyzing these issues, and evaluating and choosing among the various approaches for resolving the issues, a sound conceptual basis, or analytic framework, is necessary. To develop this framework, we specified a set of objectives for an incentive regulation program and the criteria that should be used in designing and evaluating such a program. Then, we identified issues or considerations that must be addressed in defining a comprehensive program.

PROGRAM OBJECTIVES AND CRITERIA

The primary objective of utility regulation and, hence, an incentive regulation program, should be to ensure that electrical service is provided to customers at the lowest possible price consistent with a satisfactory level of service quality. In addition, in designing a program to promote this fundamental objective, we believe that four secondary objectives should be considered and, to the extent possible, reflected in the incentive regulation program. Under these secondary objectives, an incentive regulation program should:

- Provide a utility with a reasonable opportunity to earn a fair return on its investment.
- Provide signals to utility management to plan and operate efficiently, both in the long-run and the short-run.
- Distribute to utilities a share of the benefits or losses resulting from changes in their performance. Ideally, this share should equal the financial reward or penalty required to encourage companies to improve or avoid deterioration in performance.
- Be applied in a fair and objective manner so as not to penalize or reward firms arbitrarily for performance results that are beyond the company management's control.

With these objectives in mind, we specified eight criteria that should be used to guide the design and evaluation of incentive regulation programs. Such programs should:

1. Promote long- and short-run production efficiency. An incentive program should encourage a company management to make decisions regarding the expansion or modification of the firm's capital stock and other long-term planning and operations activities (e.g., load management programs) that will minimize the present value of total cost of service, while maintaining acceptable reliability and service quality. For example, an incentive program should not cause a firm to forego long-term, cost-reducing investment opportunities (e.g., converting a generating unit from oil to coal combustion) because the investment would increase its costs in the short run. In addition, an incentive program should provide signals for efficiently combining factor inputs (the materials, labor, etc. in a firm's production process that are used to produce output) in the short run to produce electricity. For example, an incentive program should not be addressed at a narrow component of utility operations (e.g., fuel cost per unit of output) in such a way that it will encourage an inefficient substitution of other factor inputs (e.g., operating and maintenance) for the input on which the incentive program is based. In general, to accomplish these results in both the long- and short-run, an incentive program should be allocatively neutral; that is, it should not distort the firm's perception of the market price and associated marginal value of the factor inputs in the production process.

2. Encourage improvements in performance. To encourage performance improvements, an incentive program should be structured so that a firm has a reasonable opportunity to incur rewards and/or penalties when its performance deviates from selected standards or measures. In addition, these rewards or penalties must be of sufficient magnitude to make the firm respond to the incentive program. Inasmuch as possible, a program should be structured so that management is directly affected by the rewards or penalties incurred by a firm, because it is management who must accomplish any improvements in performance. Thus, the more directly management is affected by a program, the more likely the program will achieve its desired results.

3. Encourage management to bargain aggressively in purchasing the firm's factor inputs. Although pecuniary improvements (e.g., reductions in the price paid for an input as a result of bargaining) do not represent improve-

ments in economic efficiency or productivity, they may lead to reductions in the cost of service to ratepayers. Accordingly, an incentive mechanism should encourage utility managers to bargain strenuously and obtain the best price for factor inputs in markets that are not purely competitive.

4. Eliminate opportunities for management to manipulate the program to earn rewards that are not based on benefits to ratepayers. Firms should not be able to create the appearance of performance improvement (and, in conjunction, earn a reward) by actions or manipulation of accounting that result in no real benefit to consumers. For example, the rules of an incentive program should not permit management to reduce its performance in a one time period without incurring a penalty and then later regain its previous performance level while earning a reward for the supposed improvement.

5. Be structured so that the distribution of benefits or losses between a company and its ratepayers can be controlled. The incentive program should provide some means of transferring to ratepayers a share of the economic benefits or costs that result from a company's performance under an incentive program. To the extent possible, this sharing device should be able to be controlled externally, objectively, and consistently. In keeping with our general rule that an incentive program should benefit ratepayers, a firm should receive only that share of benefits that is sufficient to encourage it to achieve improvements, so long as the net value of improvements to ratepayers remains positive.

6. Incorporate performance evaluation measures and reward/penalty provisions that are fair and reasonable, and that are applied in an objective and non-arbitrary fashion. Insofar as possible, the means by which a utility's performance is measured and evaluated (whether implicitly or explicitly) should not involve subjective judgment. In addition, the performance evaluation component of an incentive mechanism should stress fairness by controlling for factors or events that may affect a company's apparent performance, but are beyond management's control. Finally, the penalty or reward associated with a level of performance should not be open to subjective manipulation by regulators or the firm. For example, it serves little benefit

to design a complex incentive rate-of-return mechanism if the base rate of return to which incremental adjustments are made can be manipulated by regulators or the firm.

7. Have expected cost-savings that exceed any increase in revenue requirements associated with potential increases in the firm's cost of capital. In implementing an incentive program, regulators must take prospective increases in investor risk into account. Specifically, programs that encourage performance improvements by placing the level of a firm's revenues or income at greater risk (e.g., an incentive rate-of-return program will increase uncertainty about the level of future earnings) will likely increase both the variance of a firm's earnings before interest and taxes, and the covariance of this value relative to that of other uncertain capital assets. As a result, a firm may receive a lower bond rating and commensurately higher debt costs. In addition, its cost of equity capital may increase as investors will require a higher risk premium (above an alternative riskless return) in order to hold the equity of the firm. These increases in cost-of-capital will lead to higher revenue requirements if the firm is to remain in business. Accordingly, it is important that any increase in the cost-of-capital associated with an incentive program not outweigh the expected dollar savings to ratepayers associated with implementing the mechanism.

8. Be administratively practical. The administration of an incentive program should not impose an unreasonable burden on regulators or utilities Inasmuch as possible, the incentive mechanism should not require an effort beyond that required in the conventional regulatory process. Also, the data that are required in measuring and evaluating performance in an incentive program should be readily available.

PROGRAM ISSUES

To assist in defining a comprehensive incentive regulation program, we have identified six issues that relate to various program components which may be specified in different ways. Once specified, these components define the program and provide the basis for evaluating its effectiveness in promoting performance improvements and, ultimately, reducing costs to ratepayers. These issues are delineated in the remainder of this chapter. In subsequent chapters, we discuss each issue and recommend approaches for specifying the components of an incentive program which are consistent with our evaluation criteria.

1. At what aspect of utility performance should an incentive program be targeted? This question is perhaps the most fundamental consideration in defining an incentive program. Once this aspect is selected, appropriate measures of performance can be targeted; it will also be important in specifying the terms of sharing losses and gains between the company and its ratepayers. An incentive program may be focused on:

- Aggregate performance for the entire company,
- Performance in a functional subset of the firm's activities (e.g., generation, transmission, or distribution),
- Performance in the service of a market subset or subsets of the firm's activities (e.g., retail operations or residential sales),
- Performance in the use of a subset of the firm's factor inputs, and/or
- Performance at a subfirm level of operations (e.g., specific generating units).

2. How should performance be measured? Utility performance measures should correspond to the aspect of performance at which the incentive program is focused. Examples of performance measures include total factor productivity indexes, aggregate cost measures, disaggregated unit cost measures, and disaggregated measures of physical production efficiency.

3. How should performance be evaluated? A firm's performance may be evaluated by comparing it with the historical performance of the company or an aggregate of similar companies, the projected performance of the company, the contemporary performance of other similar companies, the contemporary performance of some cost or price index, or a defined standard of productivity. In evaluating performance, measurement and comparisons may be made on a static basis (i.e., what is a firm's performance at an instant in time?) or on a cumulative basis (e.g., over a given period of years). Another

consideration in measuring and evaluating performance is the length of time over which performance should be measured in order to dampen extraneous fluctuations in utility operating circumstances that are beyond management's control but affect its apparent performance.

4. How should the incentive mechanism operate? An incentive program will contain a mechanism for transferring rewards and/or penalties to the firm. This mechanism may affect the company's allowed rate-of-return, the allowability and timing of cost recovery or general rate levels (and thus, implicitly, earned return, or management compensation). The method by which the incentive mechanism rewards or penalizes the firm will affect the effectiveness of the program in promoting improvements and the share of benefits that may be retained by consumers.

5. How should the incentive's sharing mechanism be structured? In an incentive program, the incentive mechanism will include a provision for sharing the gains or losses in performance between a company and its ratepayers. For a firm, the sharing mechanism may include a reward, a penalty, or both. Also, we must consider the share of gains or losses that is retained by the firm, whether the distribution operates symetrically for rewards and penalties, and whether the distribution pattern is uniform over all values of gain or loss that may accrue to a firm. Another element of an incentive program's structure that must be addressed is whether the sharing mechanism operates uniformly over time. For example, does the firm receive a share of the gains or losses associated with a level of performance that declines over time as an increasing share of the benefit or loss is transferred to ratepayers?

6. How should the incentive program control for factors and events that are beyond management's control? To operate fairly and objectively, an incentive program should not reward or penalize firms for performance results that are largely attributable to factors or events beyond management's influence. For example, adjustments for factors such as basic differences among utilities' characteristics may be explicitly included in the performance evaluation/incentive mechanism components of an incentive program. In some instances, if a comparison among firms provides the basis for performance evaluation, adjustments for external

factors may not be required to the extent that a factor (e.g., input price inflation) more or less affects all firms uniformly. However, there may remain other, less systematic factors or events that may be difficult to control by a simple adjustment procedure. These factors (e.g., lengthy plant shutdown because of the discovery of design flaws in a specific type of nuclear generating unit) may require special, discretionary adjustments by regulators in administering a program.

2 FOCUS OF AN INCENTIVE REGULATION PROGRAM AND ASSOCIATED PROCEDURES FOR MEASURING AND EVALUATING PERFORMANCE

The issues involved in designing an incentive regulation program can be grouped into two broad categories:

1. The issues associated with the aspect(s) of utility performance that a program will be designed to improve. These issues include selecting the aspect of performance on which the program will be focused, and designing the procedures for measuring and evaluating the firm's performance as a basis for granting it rewards or penalties under the program.

2. The issues associated with the design of the program's incentive mechanism. Designing a system for encouraging a firm to improve its operations with respect to the program's selected performance focus involves several issues; these include specifying how a firm will receive rewards or penalties for its performance and structuring the reward/penalty framework of the program.

In this chapter, we discuss the issues in the first category. Consistent with the program objectives listed in Chapter 1, we recommend that an incentive regulation program be focused on a firm's aggregate cost performance. This focus encourages the firm to meet the major objective of an incentive regulation program: minimizing both the short- and long-run costs of electricity to consumers at an acceptable level of service quality. We first present arguments in support of this recommended program focus and then discuss procedures for measuring and evaluating the firm's performance relative to this focus. The second category, the issues involved in designing a program's incentive mechanism, is addressed in Chapter 3.

SELECTING THE FOCUS OF AN INCENTIVE PROGRAM

The first issue that must be addressed in designing an incentive regulation program is deciding on which aspect of a utility's operations the program should focus. The choice of program focus will directly affect the specification of procedures for measuring and evaluating a firm's performance as a basis for granting rewards or penalties to it. The focus of the program should relate to the aspect of utility operations that regulators desire to improve and could include:

- The aggregate cost performance of a utility in providing electrical service,
- The firm's performance in a functional subset of its activities (i.e., generation, transmission, distribution, or plant construction)
- The firm's cost performance in serving a specific market subset(s) (i.e., retail and wholesale operations or residential, commercial, and industrial sales),
- The firm's cost performance in the use of a subset(s) of its factor inputs (e.g., fuel, labor, operations, and maintenance, or generating unit performance and availability), or
- The aggregate cost performance at the subfirm level (e.g., performance of a specific generating station).

On balance, we recommend that an incentive regulation program be focused on the first aspect, the aggregate cost performance of the firm in providing electrical service to its customers, as might be indicated by some gross measure of the utility's cost. We define cost in this case to cover all supplies and services required for the generation, transmission, and distribution of electricity. This category includes the cost of short-term variable inputs to the production process (i.e., fuel, labor, purchased power, and other materials and supplies), the currently attributable cost of fixed capital inputs (which include both return of, and a reasonable allowance for return on, capital), and the cost to consumers associated with losses of electrical service.

Four arguments support our recommended focus. First, an aggregate cost performance focus is consistent with the primary objective of an incentive regulation program: minimizing cost-of-service to ratepayers at an acceptable quality of service level. By embodying this objective in the program's design, a program is more likely to realize this desired result than a program which focuses on only one or a few aspects of a utility's costs.

Second, an aggregate cost performance focus should not affect the firm's perception of the market prices of its factor inputs.

In this way, the program should be allocatively neutral and thus avoid giving potentially inefficient price signals to a firm that could be created when a program focuses on only a subset of a firm's factor inputs or operations. A program with a subset focus will very likely distort the firm's decisions regarding the combination of inputs which yield the smallest cost of production and, in general, may lead to an inefficient substitution of inputs for the input that is the focus of the program. For example, if a program is specifically focused on fuel use, the firm could perceive a different marginal value in production from using this input than would be indicated by the market price for the input. Specifically, if an incentive program is based on fossil fuel use efficiency (as indicated by the fossil fuel cost per kWh of net generation), then the firm will perceive fuel prices to be higher than indicated by the market. As a result, the firm will be encouraged to substitute, perhaps inefficiently, lower-quality, lower-price fuels for higher-quality, higher-price fuels. While this substitution may lower the utility's fossil fuel costs per kWh of net generation, it would also increase maintenance costs and outage rates for its fossil-steam generating units. Thus, the cost of delivered energy to consumers may not decrease, and may actually increase, because of the fuel substitution induced by the incentive program.

Similar distortions may be induced by emphasizing the performance of a subset of a firm's functional operations (e.g., generation, transmission, and distribution) or its service to a market subset (e.g., the cost of serving residential customers). In these cases, a firm will be encouraged to exert special effort in improving only one aspect of its operations (e.g., generating unit availability) to the potential detriment of other areas. For example, a program oriented at managing retail rates in one regulatory jurisdiction may encourage a firm to adopt accounting and cost allocation procedures that will shift these costs to other jurisdictions. Specifically, in developing rates, a firm may be encouraged to allocate its costs in a manner that artificially understates its costs in the focal area of the program. Such a program may give a firm both the incentive and the opportunity to improve its apparent performance (and not necessarily its actual operating performance) through accounting methods.

Third, an aggregate performance focus should eliminate problems that could result if the administrators of an incentive regulation program attempted to second-guess utility management on the specific aspects of a firm's operations. Because of their general lack of direct involvement in a firm's operations, utility regulators will not be better able than utility management to make detailed decisions concerning the least-cost provision of electrical service. Specifically, to be effective, an incentive program oriented at a subaggregate level of a firm's operations would require that regulators be aware of specific operating conditions and circumstances of each utility in their jurisdiction. Using this information, regulators would, in effect, decide how a firm's current planning and operations should be modified to reduce its cost-of-service to ratepayers (e.g., a firm should increase generating unit availability). These decisions would then be embodied in the performance measures and incentive mechanisms of the programs applied to specific firms. In our judgment, regulators cannot be expected to become sufficiently involved in a firm's operations to function effectively as shadow managers of a utility. In fact, if regulators focused incentive programs on a subaggregate measure of performance and remained their usual distance from a firm's operations, the result could actually be increases in the total cost-of-service.

Fourth, a program oriented at improving aggregate performance should impose less administrative burden than the other options. As outlined in the preceding paragraph, administering a program that is focused at a subaggregate level of a firm's operations would impose a substantial and costly administrative burden on regulators. State commissions with only a few firms in their jurisdictions might be able to accommodate the expense and administrative burden of becoming intimately involved in a utility's operations.* However, for FERC, with its much larger number of regulated firms, such an involvement would be highly impractical.

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* See Appendix A for a detailed review and critique of state-implemented utility incentive programs focused at a subaggregate level of firm operations.

DEVELOPING PROCEDURES FOR MEASURING A FIRM'S PERFORMANCE

The measurement of a utility's performance is an integral component of an incentive regulation program. In conjunction with a performance evaluation procedure, performance measurement provides the basis for tracking a firm's performance relative to the objectives of an incentive program and deciding whether the firm ought to be rewarded or penalized under the terms of the program's incentive mechanism. It logically follows that, inasmuch as possible, the performance measure should encompass the selected objectives and focus of the incentive program. Keeping this criterion in mind, we considered three major issues in developing a performance measure:

1. What should be the basic measure or characteristic of a firm's performance upon which a measurement procedure is based?

2. What should be the length of time over which performance is measured?

3. Should the measurement of a firm's performance be static or dynamic?

We discuss each issue in the remainder of this section.

The Basic Measure of Performance

Consistent with our recommendation to focus an incentive program on improving the aggregate cost performance of utilities, we directed our attention to aggregate measures in developing a recommended measure of utility performance.*

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* We did not consider disaggregated cost or performance measures as a basis for an incentive regulation program; as discussed above, using such measures in an incentive program is likely to distort utility management's perception of the relative prices and marginal value of the factor inputs consumed in the production of electricity. This does not mean that disaggregated measures cannot be useful. Indeed, a firm should benefit by using disaggregated cost or performance measures to understand how its performance may deviate from that of other similar firms or from its own historical performance. Such analyses may assist a firm's management in judging if it is performing well or could undertake improvements in certain areas of its business.

These measures include total factor productivity (TFP) measures and various measures of gross revenues or gross costs per unit of electrical service (aggregate unit cost measures).

Total Factor Productivity Measures

Total factor productivity (TFP) analyses meas re the aggregate change in a firm's productivity over time for all of the firm's factor inputs (i.e., labor, fuel, capital, purchased power, and other materials).* However, we do not recommend the use of TFP measures as the basis for an incentive regulation program for four reasons. First, compared to aggregate unit cost measures, while TFP measures provide a complex view of changes in productivity, they do not focus as directly on minimizing the cost-of-service to ratepayers. Second, as a corollary, because TFP analyses focus only on productivity changes over time, they provide no information on the performance of a firm at a given point in time. (As we discuss in a later section, it is important to reflect both the level of, and change in, performance in an incentive program). Third, TFP measures are theoretically complex and involve subjective judgments in defining a calculation procedure for them. Indeed, the apparent productivity performance of a firm (both absolute and relative to other firms) may vary considerably depending upon the specific TFP analytic methodology used. These methodologies' potential vagaries in analyzing a productivity change limit the level of confidence that could be placed in TFP analyses as a practical basis for an incentive regulation program. Fourth, because of their complexity, TFP measures lack intuitive appeal and thus are less likely than aggregate unit cost measures to be accepted by utilities and their regulators.

Aggregate Unit Cost Measures

We recommend that an aggregate unit cost measure be the basic characteristic of firm performance that is encompassed in a performance measurement procedure. Aggregate unit cost measures are direct indicators of a firm's

* See Appendix B for a detailed discussion and evaluation of the use of TFP measures as a basis for an incentive regulation program.

performance with respect to its total cost of serving customers. They reflect the outcome of interrelated utility activities in producing and delivering electricity to customers and in planning to meet future electricity demand. Moreover, if they are properly designed, these measures may be appropriate for determining company cost performance across groups of comparable utilities.

To determine which measure of aggregate unit cost would be the most appropriate for an incentive regulation program, we reviewed and evaluated a number of such measures that were defined using various combinations of total expenses or revenues per kWh sold or generated. Our evaluation focused on the degree to which each measure:

- Reflects a utility's total cost of service as perceived by customers,
- Can be easily developed from data that are collected on a regular basis and made available to the public, and
- Would encourage firms to operate efficiently if it were included in an incentive regulation program.

On the basis of our evaluation, we recommend that an aggregate unit cost measure, defined as total revenues from the sale of electricity, divided by total kWh sales to retail and wholesale customers plus losses, be used. This definition directly coincides with the major focus of an incentive regulation program: minimizing the aggregate cost of providing electrical service to ratepayers at an acceptable quality of service level.*

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* In the limit, the definition of our recommended revenue-based performance measure is equivalent to an expense-based measure of a firm's total cost of doing business, including return on capital and income taxes. As an alternative to these equivalent measures, we considered an expense-based measure that excluded return on capital and income taxes. However, this type of performance measure creates an incentive to substitute capital for other factor inputs. Thus, we decided that the recommended aggregate cost measure should reflect both return on capital and income taxes to eliminate this input substitution bias.

In addition to meeting the primary goal of incentive regulation, the use of this measure shows several other advantages. First, it reflects the utility's total electricity costs as perceived by ratepayers, including a return on capital to the utility's investors. Second, the data required to compute this measure are readily available to FERC and state regulators. Third, an incentive program tied to this comprehensive cost measure will encourage firms to minimize their costs (and, in turn, their rates) with respect to their current operations, long-term capital expansion, and financial structure. The recommended unit cost measure will not disturb the firm's perception of the market prices for its inputs.* Accordingly, using revenues per kWh as the basis for measuring and evaluating performance should lead to economically efficient decisions by firms as they seek to minimize both the short- and long-run costs of providing electrical service. Moreover, centering the performance measure on revenues per kWh will give firms the incentive to bargain aggressively in the purchase of factor inputs (e.g., selected types of labor) for which the firm is not purely a price taker.

As we noted above, the data required to develop our recommended performance measures are publicly available. Following the nomenclature of the FERC system of accounts for Class A and Class B electric utilities, the revenue and kWh sales data** necessary to estimate this measure are accounted for in accounts:

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* By including return on capital, however, the recommended measure may create a conflict of interest between management and shareholders in an incentive regulation program that links management compensation to aggregate cost performance. This potential conflict, in our opinion, is less important than the input substitution bias that would be created by a performance measure that excluded return on capital (see footnote on page 2.7).

** Because they are unrelated to the prices paid by customers for delivered electricity, we excluded the following revenue accounts from the definition: 450 (forfeited discounts), 451 (miscellaneous service revenue), 453 (sales of water and water power), 454 (rent from electric property), 455 (interdepartmental rents), and 456 (other electric revenues).

- 440 (residential sales)
- 442 (commercial and industrial sales)
- 444 (sales for public street and highway lighting)
- 445 (other sales to public authorities)
- 447 (sales for resale), excluding revenues from, and the quantity of, opportunity sales
- 448 (interdepartmental sales).

The inclusion of kWh losses in the denominator reflects the requirement that utilities with large service areas and, accordingly, large transmission/distribution systems, must provide more generation to service a given level of retail and wholesale sales. Data on kWh losses can be found in the Electric Energy Account (page 401) of FERC Form No. 1 for Class A and Class B electric utilities.

In defining our recommended cost measure, we have excluded revenues from, and quantity of (in kWh) opportunity sales,* which are booked in FERC Account 447 (sales for resale). This exclusion eliminates a problem encountered by analysts in trying to define an aggregate cost measure using the FERC system of accounts.** Specifically, opportunity sales (e.g., economy interchange transactions) are typically served by a firm from its marginal generating capacity at any point in time. As a result, the cost of this generation activity and its associated average revenues may often be higher than the average revenues per kWh that are generally realized by a utility. Thus, including revenues from, and the quantity of, opportunity sales could lead to a false perception that the utility's average cost (price) per kWh of delivered energy is higher than is actually the case. A high level of opportunity sales might indicate a utility's aggressiveness in

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* An opportunity sale is a short-term, non-firm sale made by a utility over some time period using generating capacity that is not needed to meet the utility's normally expected load in that time period.

** For example, see: Tenenbaum, B. W. The Measurement of Relative Productive Efficiency Among Privately Owned Electric Utilities. Unpublished Ph.D. dissertation, University of California at Berkley, October 1980, pp. 62 and 250.

maximizing the use of its existing generating equipment (and, thereby, a reduction in costs perceived by customers if some or all of the profits from the sales are flowed through to customers). However, without the adjustment we have described, this aggressiveness in reducing costs paid by customers would be misinterpreted as an increase in the utility's costs.*

If data were available, we would propose an additional adjustment to our recommended cost measure to reflect quality of service. In developing an incentive program to encourage firms to minimize the price of their electrical service, a performance measure must ensure that firms do not sacrifice their service quality to cut costs. A reduction in service quality, for example, could be indicated by an increase in the number of full or partial outages (a partial outage could be a voltage reduction).

To protect against this possibility, a performance measure should reflect the quality of service provided by a firm. One approach to this adjustment would be to increase the numerator of our recommended cost performance measure by an amount equal to the estimated cost to consumers from electrical service that is demanded by customers, but not provided to them by the utility. To make this adjustment, we would need an estimate of the amount of energy not served during a time period (e.g., a year) because of generation, transmission, or distribution system failures and voltage reductions, and an estimate of the cost per kWh to consumers from not receiving this energy.

In recent years, a number of analysts have attempted to estimate the costs incurred by various customer classes as a result of full outages of varying duration (e.g., day, time of day, time of year) and circumstances (e.g.,

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* In a previous footnote, we argued that our recommended revenue-based cost measure is equivalent to an expense-based measure that includes a utility's total costs. If an expense-based measure were developed, we would recommend reducing the utility's production-related expenses by revenues from opportunity sales booked in Account 447 to reflect the costs of making these sales as well as the flow-through to customers of profits from the sales.

with and without notice).* The results of these analyses could provide a basis for attaching a cost to consumers for the energy not served by a firm due to a full loss of electrical service. However, to our knowledge, no estimates have been developed for the cost of voltage reductions associated with "partial outages." These costs are often assumed to be insignificant so long as voltage is sustained at a level sufficient to prevent damage to electrical motors. Although there are probably some minor costs associated with voltage reductions, it may not be unreasonable either to ignore these costs or assign them a very low value.

The remaining information required to adjust the measure to account for losses of service is to determine the quantity of energy not served in full or partial outages. Unfortunately, we are not aware that any electric utility reports such data to its regulatory commission. If such data were available, multiplying the assigned cost per kWh of lost service times the quantity of energy not served would yield an estimate of the cost to customers from lost service. This cost would be added to the numerator of the measure of average cost to consumers per kWh of electrical service and, accordingly, would provide an incentive to firms not to sacrifice quality of service as a means of reducing apparent consumer cost.

Because of the complexity of the adjustment described above, FERC may choose to implement an unadjusted cost measure. In this case, FERC would have to exercise care to ensure that firms did not let service quality slip as a means of reducing their costs. To meet this requirement, FERC would have to obtain data from utilities on changes in their service quality over time. A relatively simple reporting format could be developed to provide these data on an annual basis.

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* For example, see: Ontario Hydro. Estimating the Costs of Power Outages. Unpublished working paper, April 1979; and Resource Consulting Group, Inc. The Cost of Electrical Supply Interruptions: Report prepared for the Boston Edison Company and the Electric Power Research Institute, April 1981.

Length of Performance Measurement

In measuring average revenues per kWh for utilities, the basic measurement period for which data are now available is one year. However, we recommend that the measure be computed over a longer period to dampen the effect of year-to-year random variations in a utility's operating conditions (e.g., climatically induced fluctuations in load levels) and to broaden the time horizon over which an incentive program rewards or penalizes a firm's performance. That is, management should be encouraged to minimize costs both in the short- and long-run. By measuring cost performance over a period of several years, utility management will be encouraged to consider longer-term approaches to controlling costs, even though such approaches may lead to temporarily higher rate levels than might otherwise be attained (but in return for lower rates in the future).

The selection of an appropriate measurement period is somewhat subjective. We recommend that cost performance be averaged over at least a five-year period (in a subsequent, more detailed discussion of an incentive program in Chapter 4, we use five years as the averaging period). In addition, we recommend that a non-uniform weight structure be used in cumulating the annual data. Specifically, greater importance should be attached to cost performance in the more recent years of the measurement period. To achieve this result, declining weights (that sum to one) should be used to sum the annual data in calculating the five-year averages.

One approach to developing the declining weights would be to discount prior years' performance using a consumers' discount rate. For example, if a 10-percent discount rate were used, then the weights would decline exponentially as follows:*

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* The weights are determined mathematically by the formula:

$$\text{weight}_t = e^{-rt} \div \sum_{t=0}^{4} e^{-rt},$$

where r is the consumers' discount rate and t = 0 represents the current year, t = 1 represents the current year less one, etc.

WEIGHT STRUCTURE FOR CUMULATING ANNUAL PERFORMANCE DATA

Year	Weight
Current	0.242
Current-1	0.219
Current-2	0.198
Current-3	0.179
Current-4	0.162

As an example of how such an averaging procedure would work, consider a firm with the following average revenues per kWh over a period of five years:

AVERAGE REVENUES PER kWh

Year	Average Revenues per kWh
Current	$0.63
Current-1	$0.61
Current-2	$0.54
Current-3	$0.52
Current-4	$0.46

The five-year average revenue level for this firm would be computed as follows:

FIVE-YEAR AVERAGE REVENUE LEVEL

Year	Average Revenue per kWh	x	Weight	Weighted Annual Average Components
Current	$0.63		0.242	$0.152
Current-1	$0.61		0.219	$0.134
Current-2	$0.54		0.198	$0.107
Current-3	$0.52		0.179	$0.093
Current-4	$0.46		0.162	$0.075

Five-Year Average Revenue per kWh = $0.561

As may be seen, this five-year-average ($0.561) is higher than the simple arithmetic ($0.552), indicating the greater weight attached to performance in the more recent years, which, in the example, have relatively higher annual average revenues per kWh.

Static vs. Dynamic Measurement

In measuring aggregate cost performance as part of an incentive program, we must consider whether the measurement should be made on the level of average revenues (static measurement), the change in average revenues (dynamic measurement), or both. On balance, we recommend that an incentive program and, in conjunction, the measurement of performance, be structured to encompass both static and dynamic performance. In this way, a program can be structured to encourage firms to strive for both low rates at any instant in time and low growth in rates over time. Specifically, an incentive program should:

- Encourage a firm that has high rates at the beginning of an incentive program to reduce the growth in its rate levels.
- Encourage a firm that has low rates at the beginning of an incentive program to maintain its low rates. For a firm with low rates, further reductions (relative to a target) may be difficult.

In measuring dynamic performance, we recommend that a five-year average of rate levels (calculated as described in the preceding section) be used as the base against which change is measured. For example, change might be measured by comparing the average revenue level for the most revent year with the average of revenues per kWh for the five years immediately prior to the most recent year.*

If both dynamic and static performance are encompassed in a performance measurement and evaluation procedure, it will be necessary to develop some scoring index for both components of the performance measure. The scoring index will typically be a part of the evaluation procedure, which we discuss in the next section. These scores may then be combined using weights. The specification of weights for combining the measures of dynamic and static performance is somewhat subjective and need not be uniform across all the firms participating in an incentive program. For example, it may be desirable to use weights that vary depending upon the static position of a firm's average revenues relative to those of other firms or some other standard of evaluation. A variable weighting scheme may prove especially effective in rewarding firms with low relative rates for maintaining their low rates, even though the rate of growth in their rates could be higher than either that for other firms or a general performance target. We describe such a weighting procedure in detail in Chapter 4, in conjunction with our discussion of a recommended comprehensive incentive program.

SPECIFYING A BASIS FOR EVALUATING PERFORMANCE

Linking performance measurement to an incentive mechanism requires that some evaluation procedure be used for judging whether a utility's observed performance is sufficiently

* For a discussion of a utility-sponsored incentive program that incorporates a similar type of rate change measure, see the discussion of Utility B in Appendix G.

good (or poor) to warrant a reward (or penalty). A utility's performance could be evaluated relative to:

- The contemporary performance of other utilities,
- The utility's own historical performance,
- The historical performance of other utilities,
- A standard or index defined on the basis of cost or performance data from a non-utility industry that are assumed to be reasonable indicators of the performance of utilities.

Of these five alternatives, our first preference is for evaluating a utility's static and dynamic performance relative to the performance of other utilities during the same time periods. In addition, as a second choice, we recommend the use of an index of the cost of utility production inputs as a basis for evaluating the dynamic cost performance of a utility.

Current measures of a utility's performance, either static or dynamic, relative to its own historical performance or that of other utilities are inappropriate because the conditions affecting a utility's current performance may diverge considerably from the circumstances prevailing in previous periods. Accordingly, unless it is possible to control for intertemporal variations in operating circumstances, there is no strong basis for expecting that historical performance should presage or set a standard for future performance. Last, because of comparability problems, we also do not favor evaluating utilities relative to non-utility indicators of performance (e.g., evaluating a utility by comparing its rate of change in average revenues to the rate of inflation as measured by the Consumer Price Index).

In the following sections, we discuss our two preferred approaches to evaluating utility performance.

Evaluation Relative to the Contemporary Performance of Other Utilities

Comparing a utility's static and dynamic performance in managing its total costs to the contemporary performance of other utilities does not require controlling for intertemporal changes in the business circumstances confronting firms. For example, to a large degree, at any instant in time, utilities face similar circumstances with regard to general economic conditions (e.g., input price inflation, condition of capital markets). Using a contemporary comparison will eliminate the need to control for changes in these conditions over time.

However, in using this evaluation procedure, the comparison among firms should account for differences in the contemporary business environment of firms that are beyond management's control and that affect the cost of service of each. Controlling for these differences across firms may be accomplished by forming groups of firms that are similar with regard to their pertinent business environment characteristics. The characteristics that should be accounted for in forming comparable samples of utilities should include, to the extent possible, such factors as:

- Total generating capacity
- Average load factor
- Historical and forecast load growth
- Percent of sales to residential and commercial customers
- Stringency of environmental requirements
- State and local tax burdens.*

One issue that must be confronted in specifying the characteristics for forming groups of firms is whether or not to account for past, long-term decisions by a firm's management that may affect its apparent performance in the future. Our suggested list of pertinent characteristics that could

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* In a proposed rulemaking concerning the determination of generic rates of return for the utilities it regulates, the FERC indicated that it would examine procedures for grouping utilities into three risk classes. During this rulemaking, the Commission might also address potential procedures for grouping utilities on the basis of some of the factors discussed above. See: Federal Energy Regulatory Commission. "Generic Determination of Rate of Return on Common Equity for Electric Utilities." <u>Federal Register</u>, Vol. 47, No. 169, August 31, 1982, pp. 38332-38346.

be used to form groups of comparable utilities excludes utility-specific characteristics that result from previous management decisions (e.g., reserve margin or capacity mix) which may not be modified easily in the short-run, but will affect the firm's current and future performance. The exclusion of such characteristics ensures 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. Therefore, we do not favor controlling for previous management decisions in forming the base period comparison groups.

However, we recognize this important and difficult issue must be addressed in designing a performance evaluation program. Accordingly, the administrators of an incentive program might decide to use a firm's characteristics that depend on past management decisions in grouping firms. If such characteristics were used in developing groupings at the outset of an incentive program, the measure of a firm's performance would not be affected (either positively or negatively) by the results of its past long-term strategic decisions as it began operating under an incentive program. Later, groupings might be revised based on changes in selected business environment characteristics that are relatively independent of management decisions (e.g., increasing industrial load as a percentage of total load). However, groupings on the basis of base period characteristics that result from past management decisions would never be changed. That is, with regard to capacity mix and reserve margin, the firm would remain in the same classification that it had at the beginning of the program, despite any changes that may have occurred in these characteristics. Although this approach to "handicapping" firms may have merit, its adoption as part of a performance measurement and evaluation program would lessen the potential incentive for utilities to improve those performance characteristics that reflect their long-term strategic decisions.

The selection of groups of comparable firms using the hypothesized set of business environment characteristics could be facilitated by statistical analysis. Specifically, working with data for the full set of Class A and B utilities regulated by FERC, procedures such as factor analysis or principal components could be used to collapse the hypothesized characteristics into a smaller and more practical set of characteristics or explanatory variables. Factor analysis and principal components are statistical techniques for reducing large sets of hypothesized explanatory variables into smaller sets of explanatory variables that are linear combinations of the original variables. These techniques would also assist in discarding variables that provide redundant information in explaining differences among firms' performance.*

Once a set of explanatory variables has been selected, cluster analysis could be used to group firms. Cluster analysis is an analytic technique for grouping multi-attribute observations (in this case, firms) into groups that are similar with respect to their designated attributes.** These statistical analytic techniques are well known and widely used for such problems; standardized computer programs are available for conducting these analyses.+

In addition to using these statistical techniques for grouping firms, a panel of "experts" could be used to identify sets of similar firms. These experts' groupings could then be used to judge or modify the statistical groupings. In addition, the experts' groupings could be analyzed by discriminant analysis to identify the implicit weightings on business environment characteristics that may explain the experts' classifications. This information could then be used in conducting the cluster analysis.

In forming the similar groups of firms, it will be important to maintain a sufficient sample size within each group to permit a practical inter-firm comparison and evaluation of the performance within the group. Accordingly, we recommend that comparison groups contain at least 10 firms.

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* See, for example, Johnston, J. Econometric Methods. New York: McGraw-Hill Book Company, 1972, pp. 322-331.

** Green, Paul E. and Tull, Donald S. Research for Marketing Decisions. Englewood Cliffs, N.N.: Prentice-Hall, Inc., 1978. Another useful reference is: Hartigan, John A. Clustering Algorithms. New York: John Wiley & Sons, 1975.

\+ SAS Institute, Inc. SAS User's Guide, Cary, N.C., 1979.

Once the comparison groups have been formed, the evaluation of a firm may be undertaken by considering its performance rank relative to other firms (e.g., rank of average revenues per kWh), its deviation from the average performance for the firms in the group, or some other method or ordinal or cardinal comparison and evaluation. In general, we recommend that the scaling technique for evaluating static and dynamic performance not be purely ordinal, since cardinal information on performance (e.g., revenues per kWh) is already available. In Chapter 4, we provide a detailed illustration of how a cardinal scaling technique may be employed.

As an alternative to forming groups of similar firms, it would be possible to use regression analysis to develop a normalized estimate of firm performance based on the selected explanatory variables. In this way, a firm would, in effect, be compared with all other firms regarding the set of observations on which the regression analysis is based. To apply this procedure in any year, the actual operating results of the firms would be analyzed by regression to develop an explanatory model of average revenues per kWh. This model would be used to predict a particular firm's average revenues per kWh based on its actual operating characteristics.

In that year, similar analyses would be undertaken for previous years to develop normalized estimates of the firm's average revenues in those years. In evaluating a firm's performance by this procedure, a firm's actual cost performance would be compared with its normalized performance. The normalized performance represents an average or expected performance for the specific firm, given the regression model over all firms. Accordingly, using actual and normalized results for current and previous years, the static and dynamic measures of a firm's performance can be calculated for the firm and its phantom, "expected value" competitor. As a basis for a reward/penalty index, cardinal scaling could be accomplished by taking the ratio of each firm's actual performance to its normalized or expected performance. This would result in an index of firm performance that would be distributed normally (or lognormally, depending upon the form of the regression model) with a mean of one. Values of the index that are less than one would imply better than average performance and vice versa.

Evaluation Relative to a Cost Index

Although our preferred method of evaluating a firm's performance to compare it to the performance of other similar firms (or an econometrically predicted, expected performance for the specific firm), in some incentive programs, it may be practical or desirable to use an input cost index. Specifically, in an automatic rate adjustment program (which we discuss in Chapter 5 as an alternative to our recommended incentive program), an input cost index may prove to be a practical basis for evaluating a firm's performance.

There are two reasons for not giving first preference to this method. First, the cost index probably cannot be all-inclusive. That is, the index will likely exclude most capital-related costs and, thus, as an evaluation device, impart a bias to the firm's planning and operating decisions, favoring the substitution of capital for other inputs. Second, as a comparison tool, the index assumes constant productivity and that no improvements in production efficiency result from altering the mix of factor inputs. Accordingly, unless comparisons against the index are adjusted for some expected change in production efficiency, they may give erroneous information regarding a firm's performance.

To use an input cost index as a basis for evaluating a firm's performance, it would be necessary to identify the composition of its short-term variable factor inputs (i.e., fuel, labor, purchased power, and other supplies and materials) on a unit output basis and the share of its current costs or rates that corresponds to the cost of consuming these inputs. Also, current prices would have to be specified for these factor inputs and an external means of tracking changes in these prices would have to be identified. Given the firm's mix of factor inputs, tracking these prices over time would provide the basis for developing an input price index for the firm.* Subsequently, the component of the firm's costs per kWh

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* See Appendix E for a discussion of how such an index was developed for the rail industry and Chapter 5 for a more detailed discussion of how such an index could be developed for an electric utility.

that corresponds to the consumption of inputs covered by the index could be compared with the input cost index as a basis for evaluating the firm's cost performance over time. Alternatively, changes in the input cost index could be used as a basis for adjusting the firm's rates over time. In the latter case, an evaluation of the firm's performance would be implicitly embodied in the rate adjustment procedure and performance results would be manifested in the firm's earnings performance. The input mix reflected in the cost index might be periodically recalibrated to reflect changes in the firm's input mix.

3 STRUCTURING THE INCENTIVE MECHANISM IN AN INCENTIVE REGULATION PROGRAM

In addition to providing a procedure for measuring and evaluating performance, an incentive regulation program must contain a mechanism for encouraging firms to strive for superior performance. The incentive mechanism at once sets both the reward/penalty provisions of an incentive program and the terms for sharing, between a firm and its ratepayers, the economic outcomes of improvements or deterioration in performance, as indicated by the performance measurement and evaluation procedure. Accordingly, the incentive mechanism is a critical component of an incentive regulation program because it will influence both the efficacy of the program in improving performance and the extent to which consumers benefit from the improvement.

In formulating an incentive mechanism, two issues must be considered:

1. What should be the focus of the incentive mechanism?
2. How should the sharing mechanism be structured?

We discuss these issues in the following sections.

SELECTING THE FOCUS OF THE MECHANISM

To encourage improvements in a firm's performance, an incentive program must provide a mechanism for rewarding or penalizing a firm for superior or inferior performance. To accomplish this, a mechanism could be chosen which affects: the allowed return on equity that is embodied in a firm's rates, general rate levels (both of the foregoing measures will implicitly affect earned return), or the level of management compensation.

On the basis of our review and analyses of alternative formulations of incentive mechanisms, we recommend that an incentive mechanism be structured to affect management compensation as the means by which a firm's superior or inferior performance is recognized. In structuring an incentive regulation program in this manner, regulators will not be able to direct the payment of incentive awards to specific members of a utility's management, because individual compensation is ultimately the prerogative of a firm's board of directors and shareholders. That is, a firm's management is the agent of and works on behalf of the firm's shareholders, who own the firm. However, as we will discuss more fully in Chapter 4, regulators may structure an incentive program that provides for ratepayer funding of an incentive compensation program, depending upon the evaluated performance of the firm. In this way, the firm would not have to fund incentive bonuses out of its pre-tax earnings; rather, bonuses would be contributed as an increase in revenue based on the firm's superior performance.

Three arguments support this management compensation focus. First, because a firm's management ultimately will have to implement any performance improvements in response to an incentive program, linking management compensation to the rewards/penalties associated with the incentive mechanism should increase the effectiveness of the program. In contrast, the alternative formulations of an incentive mechanism will affect the level of a firm's earnings and, accordingly, the firm's shareholders will be the initial recipients of any incentive award under an incentive program. To the extent that management owns a substantial component of the firm, then increases or decreases in a firm's earnings could substantially affect the current income or net worth of its management. However, because the utility industry can be characterized as having relatively low insider ownership, this link between earnings performance and management income will be relatively weak. For example, of the 102 electric utilities reported on by the Value Line Investment Survey, only five are listed as having more than a one percent inside ownership. In contrast, in other industries, even large capitalization firms may have substantial insider ownership (e.g., 10 to 15 percent).*

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* See: Arnold Bernhardt, Inc. The Value Line Investment Survey, various weekly issues, 1982.

Alternatively, in taking account of an incentive program's potential effect on a company's earnings, a firm's shareholders or board of directors may act to encourage management to compete for the potential earnings rewards. For example, the board of directors may institute an incentive program that links management compensation to the performance measures embodied in the incentive regulation program or to the firm's earnings performance. Although this action may increase the likely effectiveness of an incentive program which is not oriented directly at management compensation, it is certainly a more circuitous route to influence management than structuring the incentive program at the outset to focus on management compensation. In addition, there may not be a high likelihood that shareholders or a board of directors will act to implement such a plan unless, as we discuss more fully in the second argument, the incentive regulation program provides a relatively substantial reward or penalty through its potential effect on earnings.

Second, by directly focusing the reward/penalty structure of an incentive program on management compensation, ratepayers should be able to retain a greater share of the expected economic benefits from a firm's performance improvements. Put simply, ratepayers should be able to "buy" performance improvements at a lower cost through a program oriented at management compensation than one which affects earnings. More specifically, the prospective incentive compensation award or penalty will likely be less than the prospective increase or decrease in earnings required to induce shareholders to exert pressure on management to improve the company's performance. The argument is relatively straightforward: if a gross award of fixed value is distributed over a large body of shareholders (e.g., through a dividend increase), it will have a greatly diluted impact on any individual shareholder relative to the impact on individual managers if the award were distributed to management. Moreover, if a reward is received as an increase in earnings, the amount received by shareholders will be reduced by corporate income taxes (i.e., the government may receive up to 50 percent of the reward before it is perceived as an increase in personal income).

The magnitude of this dilution can be illustrated by a simple example. Assume that regulators are willing to implement an incentive program that will increase a firm's gross revenues by one-half percent and that the revenue increase may either be distributed uniformly among five percent of the firm's employees, or distributed to shareholders, after-tax, as an increased dividend payment. Using Southwestern Public Service Co. as the basis for the numerical example, an increase in revenues of 0.5 percent in the firm's 1981 fiscal year would have equaled approximately \$2.7 million. If this \$2.7 million were distributed over five percent of the firm's employees, or 114 persons, the average compensation bonus would have been about \$23,600, a bonus that most managers would be anxious to earn. In contrast, if the \$2.7 million had been distributed as an increased dividend, the value per share or per shareholder would have been considerably reduced. Specifically, assuming a marginal tax rate of 50 percent, \$1.35 million would have been available for distribution. With 32.1 million shares outstanding, the increased dividend per share would be 4.2¢. In fiscal 1981, Southwestern paid \$1.41 per share in dividends; accordingly, the percentage increase in dividends would be about three percent. For the average shareholder of Southwestern, the increased dividend in 1981 of 4.2¢ would have resulted in an additional income of \$32.58, based on 41,432 common shareholders. (However, since many shares may be held in a street name or by an institutional investor, the effective number of individual shareholders may be much larger and the dividend per share smaller.) In short, if shareholders (instead of management) are the primary recipients of an award of a given value and must be relied on to spur management to strive for improved performance, the incentive will likely have less impact on encouraging the firm's management to improve performance. As a corollary, to encourage a desired level of performance improvement, the share of expected cost reductions that may be retained by ratepayers will also probably be less under earnings-related programs than under a compensation-related program.

Third, an incentive program that affects management compensation should have a negligible effect on a firm's cost of capital. A key concern in designing an incentive regulation program is to avoid increases in a firm's cost of capital and their associated increased revenue requirements, because they will reduce or conceivably offset the reduction in revenue requirements that result from cost-saving improvements undertaken in response to the program. In general, incentive programs that affect the firm through potential increases or decreases in its operating income (e.g., earnings before interest and taxes) may lead to a higher cost of capital for the firm, because lenders and investors require higher risk premiums for holding the firm's securities. An incentive program that affects management compensation should have no effect on investors' and lenders' perception of the riskiness of a firm's operating income stream and should avoid altogether the potential problem of increased cost of capital. Indeed, if management gains better control of its operations and increases its earnings stability as a result of an incentive program oriented at compensation, it is even possible that the program could lead to reduced cost of capital.

As a final point concerning our recommendation that an incentive program reward or penalize the firm by affecting management compensation, we must recognize that a conflict of interest may develop between management and shareholders if performance is evaluated on the basis of average revenues per kWh. Specifically, management is responsible for arguing for an allowed rate of return on equity on behalf of its shareholders. At the same time, if an incentive bonus is awarded on the basis of average revenue performance, management may be encouraged to adopt ratemaking positions that improve its average revenue per kWh performance (e.g., argue for an otherwise low rate of return on equity). thus, in designing a program that affects management compensation and uses average revenues as a basis for performance evaluation, it will be necessary to include some procedure to offset this conflict of interest. Some potential means of resolving the problem include letting a committee of shareholders or the board of directors formally review ratemaking positions on critical issues adopted by management in major rate cases or excluding a firm's chief executive officer (CEO) and chief financial officer from the ratepayer-funded incentive compensation programs. In general, we recommend the latter approach to eliminate this potential conflict between management and shareholders.

STRUCTURING THE SHARING MECHANISM

The second major issue which must be addressed in the design of an incentive mechanism is the process by which the firm and its ratepayers will share the economic benefits or losses associated with changes in the firm's performance. In structuring the sharing mechanism, we must consider three questions:

- Should the incentive mechanism include a reward, a penalty, or both?
- How should the economic results of changes in performance be distributed between a firm and its ratepayers?
- How should the rewards or penalties received by a firm be distributed between a firm's shareholders and management?

The resolution of these issues will materially influence the effectiveness of an incentive program in promoting performance improvements for the benefit of ratepayers.

Specifying Rewards and Penalties

Inherent in the concept of an incentive mechanism is that a firm should be rewarded and/or penalized if its performance exceeds or falls below some standard indicated by the performance measure and evaluation procedure. An incentive mechanism could include a reward component, a penalty component, or both.

The decision to include a reward component in an incentive mechanism is not contentious: assuming that neither the pre-program base revenues of the firm nor the income of individual program participants will be adjusted downward by the program, the inclusion of a reward in an incentive program, on a probabilistic basis, will only make the entity better off. Thus, it should be acceptable to participating firms. To the extent that it offers the potential for improved firm performance in providing electrical service to ratepayers, the inclusion of a reward in an incentive program should also be acceptable to ratepayers

However, the decision to include a penalty component in a program is not so simple. The potential assessment of dollar penalties for so-called inferior performance may be impracticable and counterproductive to the goals of a program. Moreover, the assessment of dollar penalties may cause an incentive program to be politically unsaleable. Next, we discuss this issue with respect to programs that affect compensation and those that affect revenues or earnings.

Programs Affecting
Management Compensation

In this type of program, the potential assessment of a dollar penalty against the participants' income may be simply unacceptable to the firm's management. Given the consequences of personal bankruptcy or sudden decreases in personal income (e.g., risking foreclosure on a residential mortgage), individuals may reasonably behave in a risk-averse manner when confronted with the option of participating in such a program. That is, even if the program offers equal or greater opportunity for increases in their income, individual managers may effectively refuse to participate in the program unless their base salaries are increased enough to effectively offset their potential income losses. As a result, the prospective penalties may lead managers to leave firms that participate in such a program, even though they may have to accept lower, but presumably more certain, salaries in other positions. Ultimately, assuming the existence of efficient labor markets, in order for a participating firm to retain managers of equal quality to those who originally occupied the affected positions, it would have to bid up salaries to levels that offset the personal and diversifiable risk associated with accepting the positions.

In this light, we recommend that an incentive program that affects management compensation include only prospective dollar rewards in the incentive mechanism. However, depending upon the procedure for evaluating performance, it will probably be necessary to recognize poor performance and tally implicit dollar penalties against future dollar awards for superior performance. Unless there is some such procedure for penalizing poor performance, there may be an incentive for managers to game the incentive program.

Specifically, managers may be encouraged to achieve intentionally poor performance or use accounting maneuvers to achieve the appearance of poor performance if a subsequent improvement from the poor performance level will earn a reward. One way to avoid this problem would be to set a scale of negative points or dollar penalties for poor performance that may be accrued against future rewards. After a firm had earned "negative" points, it would have to work off the negative position with positive points before being eligible for dollar awards. Of course, if the firm had no negative points, the positive points would have resulted in dollar awards. Even with such an approach, there may still be a problem: if a firm accrues a large number of negative points that it must work off before receiving dollar awards, management may not perceive any reasonable opportunity for earning a reward and the incentive program may cease to be effective in promoting performance improvements. To avoid this problem, a negative account may occasionally have to be written to zero or must decay over time in some way. We discuss the resolution of this problem in greater detail in the next chapter.

Programs Affecting Revenues and Earnings

A potentially serious problem arises when dollar penalties are explicitly assessed for poor performance in a program that affects the firm's revenues or earnings. Specifically, the dollar penalties may lead to a progressive deterioration in a firm's performance if the penalty is assessed in one time period, which prevents the firm from taking steps to improve its performance in subsequent time periods. In such a scenario, the performance gap between firms exhibiting superior performance and those exhibiting inferior performance would widen over time.

In addition to this problem created by explicit dollar penalties, another problem may arise through the implicit penalties that investors may perceive in earnings-related programs that offer only potential rewards for good performance and no explicit penalties for poor performance. Specifically, the prospect of implicit dollar penalties against earnings may exaggerate the potential adverse effect on a firm's cost of capital. Though not perfectly rational, if investors and lenders behave in a risk-averse manner in valuing the firm's securities, then the prospect of a perceived deterioration in earnings or interest coverage as a result of implicit dollar penalties may increase a firm's cost of capital. The reason that the concern over a dollar penalty may not be perfectly rational is that, even with only dollar rewards, astute investors will reappraise upwards the expected earnings of a firm. Subsequently, whenever the firm fails to earn the expected incentive reward, in effect, it will have been assessed with a dollar penalty against its expected earnings. Nevertheless, there may be a sufficient psychological aversion to dollar penalties to warrant avoiding their use because of their prospective effect on a firm's cost of capital.

In view of these arguments, we recommend great care be taken in including a dollar penalty in an incentive program that would affect a firm's earnings. Again, as with the management compensation-oriented programs, it may be possible to accrue negative points against future dollar rewards as a means of assessing penalties under this type of program.

Sharing the Economic Results of an Incentive Program

Whether an incentive program includes dollar rewards, penalties or both, the method of determining the amount of reward or penalty relative to an evaluated level of performance (or said another way, the share of gains or losses retained by the firm) will crucially affect the program's ability to promote performance improvements and the extent to which ratepayers receive benefits from the improvements. Designing the incentive sharing component of a program will require selecting a general framework for sharing the economic results from improvement or deterioration in performance, and the specific numerical parameters (e.g., the fractional share of gains retained by the firm) for that general sharing framework. In the course of our analyses in this area, we have reviewed several studies that purport to prove a particular sharing framework is superior to others and that lay out rules for setting numerical percentage parameters. However, these analyses are often highly theoretical and it is difficult in real world circumstances to assess the validity of their findings and apply the theoretical prescriptions for establishing an incentive program's numerical parameters.* Ultimately, the selection of both the framework and, in particular, its numerical parameters, will involve subjective judgments by regulators concerning, for example, the amount of reward that is sufficient to induce some potential level of performance.

With regard to establishing the sharing framework and its parameters in an incentive program, we delineate the following general guidelines.

1. In linking an incentive mechanism to performance measurement and evaluation procedures, the sharing framework should be structured so that a firm's management will perceive a reasonable probability of achieving the performance improvements required to earn a reward. Similarly, management should perceive that their actions could reasonably lead to the incurrence of penalties for poor performance. The sharing mechanism should not specify an unduly wide range of performance which might be described as neutral, that is, warranting neither reward nor penalty.

2. An incentive sharing framework should never permit more than 100 percent of the economic value of a performance improvement to be retained by the firm. Otherwise, ratepayers may expect to be worse off as a result of implementing the program.

3. An incentive sharing framework should provide rewards and/or penalties that are large enough to encourage a firm's management to undertake improvements to earn a reward or avoid penalties. However, given that the fundamental objective of an incentive regulation program is to reduce costs to ratepayers, the amount of any incentive reward to a firm (or the share of the economic benefits from an improvement retained by the firm) should be just sufficient to encourage the firm, on an expected value basis, to undertake the improvement. That is, the ratepayer should realize the maximum possible share of the benefits from an improvement.

4. A sharing mechanism should probably transfer to the firm an increasing share of the economic benefits

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* For example, see: Sinden, Frank W., "Inflation Adjustment Formulas and Efficiency Incentives." Challenges for Public Utility Regulators in the 1980s. East Lansing: MSU Press, 1981, pp. 377-396.

associated with performance improvements on the margin. We may intuitively expect that, in any time period, the incentive effect required to achieve performance improvements will increase on the margin. That is, each additional performance improvement will be more difficult to achieve than previous improvements. Therefore, as the assessed dollar value of the improvements increases, the marginal and average shares retained by the firm should increase. In practice, it is probably impossible to develop prespecified numerical estimates of any firm's incentive response functions. Therefore, a weaker and perhaps more practical conclusion of this argument is that a sharing mechanism should at least provide a constant, non-decreasing share of gains to the firm.

With these points in mind, we discuss three general frameworks for distributing the economic outcomes of an incentive program between a firm and its ratepayers. As we have already indicated, selecting among these frameworks and setting numerical parameters to the frameworks will require regulators' subjective judgment based on a balancing of theoretical arguments and practical considerations.

1. Gains or losses may be shared on a constant fractional basis in any time period. In this incentive framework, a firm's actual performance (e.g., actual costs per kWh) in a given time period will be measured against some standard (e.g., a composite derived from a sample of firms). The firm will typically be rewarded (or penalized) for its performance by allowing it to retain a constant share of the difference between its actual performance and the target or standard performance (this difference is the gross gain or loss under the program). For example, the incentive mechanism proposed by Cross* essentially falls in this framework. On a less precise basis, incentive rate of return type mechanisms also typically fall within this framework. For example, the mechanism discussed in Appendix F would be set up to distribute, between a firm and its ratepayers, an approximately constant share of the gains or losses in operating cost performance. The firm would receive its share of the performance reward or penalty through incremental adjustments to its allowed return.

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* Cross, J. G. "Incentive Pricing and Public Utility Regulation." Quarterly Journal of Economics, May 1970, pp. 236-253.

A variation of this type of program would be one in which there is a variable rate of sharing that is based on the extent of deviation in actual from standard performance. Such a program could be formulated to provide an increasing marginal share of improvement benefits to the firm, thus matching the guideline that the firm's incentive sharing rate ought to increase on the margin. An advantage of fractional sharing arrangements is that they provide for explicit control of the share of gains or losses retained by the firm, as indicated by the performance measurement and evaluation procedure.

2. Gains or losses may be shared variably over time, with a firm typically receiving all of the economic gains or losses from its performance changes for a number of time periods following a performance change. Subsequently, a share, or perhaps all, of the gains or losses may be transferred to ratepayers through rate adjustments that reflect the prior change in performance. For example, the automatic rate adjustment mechanism discussed in Chapter 5 follows this framework. One advantage of this type of arrangement is that a firm has a high incentive to achieve performance improvements. For example, the firm may appropriate the full value of improved performance as an increase in earnings or a discretionary increase in management compensation, at least for some period of time.

3. Gains or losses in a time period may be shared on a variable basis in which the firm has a target rate of performance improvement that must be achieved in order for it to "break even." Under this arrangement, ratepayers receive a fixed level of the assumed improvements based on this target, while the firm bears the full share of shortfalls to the target and receives the full share of benefits above the budget. As a result, the fractional share of gains or losses that is received by the firm will vary considerably, depending upon the actual performance level achieved by the firm. For example, future test year rate regulations which assume a productivity improvement over the previous year would fall within this framework. The firm must then achieve the assumed productivity improvement in order to "break even." Concurrently, ratepayers receive the value of the target productivity improvement whether or not the firm achieves it. If the firm falls short of the target productivity improvement, ratepayers will receive more than 100 percent of the improvement. If the firm scores higher than the target improvement, ratepayers will receive less than

100 percent and the share received by the firm will increase with increases in its performance.

Sharing Incentive Awards Within the Firm

Ultimately, the distribution of rewards or penalties within a firm is the prerogative of the firm's shareholders, board of directors, and management. In this light, regulators cannot, and should not attempt to, directly control the distribution of incentive awards within the firm. However, an incentive regulation program will be most effective in promoting performance improvements and in transferring to ratepayers the maximum share of the economic benefits associated with those improvements if the program is designed to affect management compensation. In Chapter 4 and Appendix G, we present detailed information and guidelines on our recommended approach to structuring a management compensation incentive program. Although regulators should not specify the precise distribution of incentive awards within the firm, regulators may wish to have some sense of how an incentive compensation program might be structured to best promote performance improvements. As a result, we recommend that an incentive program be structured to affect management compensation indirectly by, for example, providing incentive awards as ratepayer-funded contributions to an incentive compensation pool which may be distributed at the discretion of the firm. We describe this type of incentive program in the next chapter.

4 RECOMMENDED INCENTIVE REGULATION PROGRAM

Using the analytic frame work and analyses described in the preceding chapters, we considered a number of comprehensive incentive regulation programs that might be implemented by FERC. In general, these programs focus on improving a firm's performance through explicit or implicit financial incentives directed at either shareholders or utility managers. For example, these programs range from automatic rate adjustment mechanisms (similar to the fuel adjustment clauses currently regulated by FERC) to rate of return adjustment mechanisms linked to the earnings or rate performance of electric utilities.

On the basis of our evaluation of the potential effectiveness of the different programs in improving performance, we recommend that FERC initiate steps to implement a comprehensive incentive regulation program designed to encourage utilities to maintain the lowest possible rates to consumers. Specifically, the primary objective of this rate control incentive program (RCIP) is to encourage each utility regulated by FERC to reduce the level of and growth in its electricity rates relative to that of other comparable utilities. Such reductions should be consistent with service to customers at an acceptable quality level. The mechanism by which utilities will be encouraged to achieve this objective is the payment of incentive awards, funded by ratepayers, to those utilities that reduce the level of and growth in their rates relative to comparable firms. Each utility that receives an incentive payment award under the RCIP will be required to distribute the awards to key managers in the firm, although the selection of these managers and the distribution of the firm's incentive payment awards among them will be determined by the firm's board of directors and executive compensation committee. The strength of this incentive mechanism is that it focuses on the agents of the firm who must ultimately effect any improvements in the firm's performance.

The concept underlying this recommended RCIP is to simulate a sense of price (i.e., rate) competition among comparable firms as though the firms operated in a competitive, non-regulated market. However, at the same time, the sense of price competition is achieved without placing the firms' earnings at risk, thus preserving a principal advantage of the regulated monopoly environment in which utilities operate: their low cost-of-capital relative to the cost-of-capital for firms that operate in competitive markets. We support this program because it:

- Promotes cost minimization more strongly than does the traditional regulatory process
- Creates incentives for firms to minimize their costs by efficiently combining their production resources in both the short- and long-run
- Transfers to ratepayers a major share of the economic benefits associated with performance improvements.

We recommend that FERC, working with state regulatory commissions, implement such a program.

We also recommend that FERC consider two other incentive regulation programs that may be substituted for or complementary to our recommended program. The first is a construction cost control incentive program. This program links both an incentive rate-of-return mechanism and an incentive compensation plan for a construction program's managers to a utility's cost performance in constructing major projects. The second program incorporates an automatic rate adjustment mechanism which is linked to price changes in a utility's production inputs, as measured by external price indexes. These two alternative programs are described in Chapter 5.

In the sections below, we first present a detailed description of our recommended RCIP and then delineate how selected elements of the program should be developed. Last, we discuss several difficult issues related to the implementation and administration of the program and recommend steps that FERC can take to resolve these issues.

STRUCTURE OF THE RECOMMENDED PROGRAM

In structuring the RCIP to meet its primary objective of minimizing electricity rates at an acceptable quality of service level, we addressed four major issues:

1. What should be the program's focus?

2. How should performance be measured and evaluated?

3. What type of incentive mechanism should be incorporated in the program?

4. How should the incentive mechanism be linked to performance?

In the sections below, we discuss our recommended approach for resolving these program issues.

Focus of the RCIP

An incentive regulation program for electric utilities should be structured to ensure that these regulated monopolies perform in a manner that is in the best interests of the firm's customers. Specifically, the program should encourage a utility to reduce its electricity rates relative to the rates of comparable utilities or, in the cases where the firm's rates are already relatively low, for maintaining its rate position. While it would also be desirable to create incentives for the firm to take cost-effective steps to improve or, at a minimum, maintain its quality of electrical service (as measured, for example, by such variables as frequency of complete and partial outages, average time to make repairs, and indexes of consumer satisfaction), it is difficult both to measure these variables on a regular comparative basis and to translate quality improvements into dollar benefits for consumers and utilities. Therefore, we recommend that the primary focus of the RCIP be the utility's relative rate performance, consistent with a service quality level specified by FERC (or perhaps by state regulatory commissions.

From the above discussion, it may appear that the focus of the recommended RCIP ignores the interests of shareholders and creates a conflict of interest between management and shareholders by encouraging firms to take actions to reduce their relative electricity rates. For example, managers might request and passively accept relatively low allowed returns on equity in their efforts to attain bonuses. However, as we noted in Chapter 3, several options are available to avoid this potential conflict between management and shareholders.

Such a procedure would eliminate the potential conflict between management and shareholders that might arise from an incentive program that focuses on relative rate levels as the primary measure of a utility's performance.

Performance Measurement and Evaluation Under the RCIP

The basic performance measure in the RCIP is the Rate Performance Index (RPI). This index reflects both a utility's current rate levels relative to the current rates of the other firms in its comparison group, and changes in the utility's rates over time relative to rate changes in the comparison group. In this way, the RPI combines measures of a firm's static (current) and dynamic (changing over time) performance. By reflecting these two types of performance by a firm, the RPI is a useful indicator of a utility's performance relative to a peer group of firms. In addition, the RPI may also be considered an indicator of the performance a firm might achieve if it operated in a non-regulated, competitive market. If the RPI is formulated in the manner described below, it will indicate good performance, not only by a utility that lowers its relative rate levels over a five-year time period, but also by a utility that currently has and continues to have low rates relative to comparable firms.

In Chapter 3 we recommend that a utility's performance be measured using an aggregate unit cost measure, which is basically defined as total electricity sales revenues divided by kWh sales. Consistent with this recommendation, we have attempted to formulate the RPI to reflect both static and dynamic measures of a utility's aggregate unit costs. In addition, to ensure maximum effectiveness in encouraging both low relative rates and low relative growth in rates, we designed the RPI to address three potential constraints on performance improvements. These are:

1. Firms with relatively low rates (i.e., a good static performance measure) will have more difficulty in improving their dynamic performance relative to firms with relatively high rates (i.e., a poor static performance measure). Therefore, the RPI should be structured so that it continues to indicate good overall performance for a firm that maintains its good static performance.

2. Conversely, firms with currently high rates will have more difficulty in achieving a good static performance measure than firms with currently low rates. Therefore, the RPI should be structured to reflect the benefits of gradual, but continual, improvements in firms' rate levels that may result in good dynamic performance measures but poor static performance measures.

3. Past management decisions will affect the initial static measure of a utility's performance under the RCIP. To dampen the effects of these past decisions on a firm's static performance measure, the RPI should be structured to emphasize the contributions of current management to a utility's performance.

With these constraints in mind, we developed an eight-step procedure for calculating the RPI for each firm covered by the RCIP.

<u>Step 1</u>: Assign each utility to a group of comparable utilities using the grouping procedures and techniques recommended in Chapter 3.

<u>Step 2</u>: Calculate a static performance measure for each firm in a group. This measure, in time period T for the ith firm in the group, is defined by:

$$R_{i,T} = \frac{\sum_{t=(T-4)}^{T} R_{i,t} \cdot e^{r(t-T)}}{\sum_{t=(T-4)}^{T} e^{r(t-T)}}$$

where $R_{i,t}$ is the firm's aggregate unit costs (i.e., average revenues per kWh) in time period t. (t = T-4, T-3,..., T). As we pointed out in Chapter 3, this definition reflects the greater importance to consumers of current rate levels relative to historic rate levels. In addition, the definition reflects the decreasing importance over time of past management decisions in current rate levels.

<u>Step 3</u>: Calculate a dynamic performance measure for each firm. The measure in time period T for the ith firm in the group is defined by:

$$\Delta R_i = \frac{R_{i,T} - R_{i,T-1}}{R_{i,T-1}} \times 100,$$

which represents the percentage change in the firm's current rates relative to its rates in the preceding year (i.e., ΔR, reflects rates over a six-year period).

Step 4: For each group of utilities, calculate the means of the distributions of $R_{i,T}$ and ΔR_i. The means can be denoted as $\bar{R}$ and $\Delta\bar{R}$. Then, calculate the deviations from the means of the highest and lowest values of $R_{i,T}$ and ΔR_i. Let the deviations of the highest values be represented by $\bar{D}_{max}$ and $\Delta\bar{D}_{max}$. In a similar fashion, let the deviations of the lowest values be denoted as $\bar{D}_{min}$ and $\Delta\bar{D}_{min}$. The values of $\bar{D}_{max}$ and $\Delta\bar{D}_{max}$ are negative, while the values of $\bar{D}_{min}$ and $\Delta\bar{D}_{min}$ are positive.

Step 5: Within each group, assign a value of +1 to the lowest values of $R_{i,T}$ and ΔR_i, and a value of -1 to the highest values of these performance measures. In this way, the utility with the best static performance measure (i.e., lowest rates) is assigned a static index value of +1, and the utility with the worst static performance measure (i.e., highest rates) is assigned a static index value of -1. Similarly, the utility with the best dynamic performance measure (the largest percentage reduction in rates over a five-year period) receives a dynamic index value of +1, while the utility with the worst dynamic performance measure receives a dynamic index value of -1. (It is unlikely that one utility will have the best static as well as best dynamic performance measures or the worst of both performance measures.)

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* A potential deficiency of cost-based performance measures is that they may provide utility managers with an incentive to manipulate the performance measures. This manipulation could occur by using production inputs inefficiently in the short-term to reduce costs and thereby earn a bonus for "good" performance. This short-term perspective may exist even if such actions will increase the firm's costs in the future, especially if managers expect to terminate their employment in the near future. However, the structure of the static and dynamic performance measures ensures that overall utility performance can only be significantly affected by consistent performance over relatively long time periods. Therefore, any attempt by managers to manipulate a firm's measured performance in the very short term will be ineffective under the recommended performance measures.

Step 6: For each firm in a group whose performance measure values $R_{i,T}$ and ΔR_i fall between the lowest and highest values of these performance measures for the group, assign it static and dynamic index values using one of two equations. For a firm whose performance measure values $R_{i,T}$ and ΔR_i are less than the calculated values of $\bar{R}$ and $\Delta\bar{R}$ for the group, the firm's static and dynamic index values are defined by:

$$\text{Static Index Value} = \frac{\bar{R} - R_{i,T}}{\bar{D}_{min}}$$

$$\text{Dynamic Index Value} = \frac{\Delta\bar{R} - \Delta R_i}{\Delta\bar{D}_{min}}.$$

Similarly, for a firm whose static and dynamic performance measure values are greater than $\bar{R}$ and $\Delta\bar{R}$ for the group, the firm's static and dynamic index values are defined by:

$$\text{Static Index Value} = \frac{R_{i,T} - \bar{R}}{\bar{D}_{max}}$$

$$\text{Dynamic Index Value} = \frac{\Delta R_i - \Delta\bar{R}}{\Delta\bar{D}_{max}}.$$

The reversal of the numerator is necessary to ensure that firms with below-average performance measures are assigned negative static and dynamic index values.

Step 7: Assign weights to each firm's static and dynamic index values using the following procedure. First, for the firm with the highest static index value (i.e., lowest rates), assign a weight of 0.667 to its static index value (i.e., +1) and a weight of 0.333 (i.e., 1 - 0.667) to the firm's dynamic index value. This weighting recognizes the first and third performance improvement constraints discussed earlier. Second, for the firm with the lowest static index value (i.e., highest rates), assign a value of 0.333 to its static index value (i.e., -1) and a weight of 0.667

(i.e., 1 - 0.333) to the firm's dynamic index value. This weighting recognizes the second and third performance improvement constraints discussed earlier. Third, assign equal weights (i.e., 0.5) to the static and dynamic index values for a firm that has a static index value equal to zero. For each of the remaining firms in the group, the weight assigned to the static index value is determined by the linear transformation:

$$\text{Static Weight} = 0.5 + \frac{\text{Static Index Value}}{6}.$$

The weight for each firm's dynamic index value is then given by the formula:

Dynamic Weight = 1 - Static Weight.

<u>Step 8</u>: Determine the RPI for each firm using the formula:

RPI = (Static Weight)(Static Index Value) + (Dynamic Weight)(Dynamic Index Value)

A firm's RPI value can range between -1 and +1. An RPI value of 0 indicates the firm's performance is average; a value between 0 and +1 indicates the firm's performance is above average; and a value between 0 and -1 indicates the firm's performance is below average. For example, assume the firm with the highest static index value has a dynamic index value equal to 0.5. The RPI for this firm is:

$$RPI = (0.667)(1.0) + (0.333)(0.5) = 0.834,$$

which indicates above average performance by the firm.

Similarly, assume that the firm with the lowest static index value has a dynamic index value equal to 0.6 (i.e., although the firm's current rates are high, the firm has performed better than average in reducing its relative rate levels over time). The RPI for this firm is:

$$RPI = (0.333)(-1.0) + (0.667)(0.6) = 0.067,$$

As shown by this second example, a firm's overall rate performance can be considered to be better than average, even if it exhibits poor performance measured on a static basis.

Incentive Mechanism Under the RCIP

After developing performance measurement and evaluation procedures for the RCIP, we selected an incentive mechanism that will encourage utilities to perform well over time. This mechanism is the payment of an incentive award, funded by ratepayers, to each utility whose performance exceeds the average performance of all utilities in its comparison group. A utility that receives an incentive payment award will be required to distribute the award among its key managers. By directly affecting the compensation received by a firm's key managers, the RCIP will create a strong incentive for these managers to operate the firm efficiently.

For those utilities that choose to participate in the RCIP,* the participation by individuals within a firm should be limited to managers whose actions could have a meaningful impact on the firm's rates and the achievement of overall corporate objectives. The selection of program participants should be left to the discretion of the firm's board of directors and its compensation committee. FERC should mandate neither the number nor percentage of a firm's employees to be covered by the firm's incentive compensation plan. However, it should be noted that about 75 percent of the incentive compensation plans used by non-regulated firms cover less than 0.41 percent of their employees. The median percentage of employees covered by these plans is 0.16 percent.** Similarly, in the three utility-sponsored plans reviewed in Appendix G, the percentage of employees participating in these plans ranged from about 0.2 percent to approximately 0.5 percent. Although FERC should not control the selection of program

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* As we discuss later in this chapter, participation in the RCIP will be on a voluntary basis.

** Bickford, L. C. "Long-Term Incentives for Management, Part 6: Performance Attainment Plans." Compensation Review, Third Quarter 1981, pp. 14-29.

participants, it will, as we describe later, be able to control the size of the aggregate level of incentive award payments that can be made for each firm that participates in the RCIP.

The selection of an incentive mechanism linked to management compensation is based on two factors. First, a management incentive compensation program has several advantages over an incentive mechanism linked to a firm's earnings. Second, incentives provided by the management compensation element of the RCIP should be effective in promoting performance improvements in the electric utility industry. We discuss these two factors below.

Advantages of Management Incentive Compensation Programs

Incentive programs that affect management compensation, such as our recommended RCIP, have three major advantages over programs that reward or penalize a utility's performance through increases or decreases in the firm's earnings. First, a compensation-related program will have a more immediate impact on performance than a program that affects earnings. Specifically, because performance improvements must come from actions taken by a utility's management, the potential for managers to earn direct financial rewards will both immediately encourage existing managers to perform better and enable a firm to attract and retain top-quality managers. However, the realization of improved management performance under an incentive program that affects earnings is tenuous. If shareholders were able to agree among themselves on the management changes which need to be made to improve their firm's performance and acted quickly and cohesively to encourage improved management performance, then the possibility of higher earnings from more efficient utility performance would potentially be as effective as direct incentives to management. However, achieving such agreement among thousands of shareholders is an unlikely event.

Second, and as a corollary of the first advantage, the dollar magnitude of a financial reward or penalty that will be required to effect a change in a firm's performance should be much less under an incentive program that affects management compensation than a program that affects a utility's earnings. Accordingly, ratepayers will be able to retain a greater share of the benefits from cost-reduction innovations introduced by management in response to compensation-related incentives. For example, the dollar cost to consumers of a financial reward for improved performance will be significantly less if it is paid as a 25 percent salary bonus to key managers than as a one percentage point increase in the return on equity earned by shareholders.

The third advantage of a compensation-related program is its lack of influence on a firm's cost of capital. Specifically, unlike earnings-related programs, a compensation-related program should not increase a utility's cost of capital. This advantage may be quite significant to ratepayers over the long-run.

Effectiveness of Management Incentive Compensation Programs

The use of our recommended RCIP in a regulatory setting would represent a significant departure from traditional rate regulation in the United States. We are unaware of any regulatory commission's formal use of inter-company comparisons of rate performance as a basis for incentive regulation. Moreover, no regulatory commission has attempted to improve utility performance through a compensation-related incentive mechanism. However, the type of incentive mechanism in the RCIP has been tried and tested for several years.

Incentive compensation plans have been used extensively in non-regulated industries to provide executives with incentives to perform in a manner that is consistent with their shareholders' interests.* A number of different incentive mechanisms have been used in these programs. One of the first was the use of long-term contracts under which managers received continually increasing compensation levels if they performed well and stayed with the firm.**

* Miller, M. and Scholes, M. "Executive Compensation, Taxes, and Incentives." Financial Economics: Essays in Honor of Paul Cootner. Edited by Katherine Cootner and William Sharpe. New York: Prentice-Hall, 1981.

** Lazear, E. "Why is There Mandatory Retirement." Journal of Political Economy, December 1979, pp. 1261-1284.

A second and more direct incentive mechanism that has been employed is the use of stock options or other compensation agreements that tie an executive's compensation to the market performance of his firm's stock.

While stock options were used extensively during the 1960s to reward corporate executives in the non-regulated sector, they have come into disfavor in recent years as stock prices have generally remained constant or declined, even in the face of relatively strong earnings performance.* As a result, many firms have recently adopted alternative forms of incentive compensation plans, under which executives' compensation is tied directly to the performance of the company and not to the performance of its stock. A key feature of these plans is that they tend to be long-run in nature; performance goals are typically measured over a multi-year period to encourage executives to focus on what is best for the company over the long-run. Under such schemes, actions which temporarily keep costs down (e.g., deferring selected expenditures that the company will incur in the near future) will not lead to any rewards for the executives.

Currently, over 40 percent of the 200 largest U.S. industrial companies have adopted systems of long-term performance attainment awards; the first of these plans went into effect in 1971. In order to tie the amount of executive payments directly to a corporation's financial well-being over a number of years, many of these programs focus on such performance measures as return on equity, absolute earnings growth, and earnings growth relative to a set of competitors (which controls for cyclical factors). Participation in these plans typically is restricted to a small number of executives; the median number of participants as a percentage of all employees for corporations with such plans is about 0.16 percent.** Participation appears to be limited both because payments under such plans are treated as a direct charge to the company's earnings and because only employees with fairly high positions in the corporate hierarchy are thought to have a substantive impact on corporate goals through their decisions.

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* Bickford, op. cit.

** Ibid.

The performance measurement periods of most programs vary between three and five years, apparently because less than three years is too short to measure long-term performance, while more than five years is too long to make executives wait for awards; in this case, the system might not achieve its desired motivation effect. Some companies institute new incentive programs each time a program expires (e.g., every three years), while others have overlapping programs (e.g., every two years a new three-year plan is begun). While the former system is obviously simpler, it suffers from the problem that extremely poor firm performance in the first year of a plan may render the firm's performance in subsequent years almost irrelevant in terms of employees' rewards under the plan. With overlapping programs, good performance in subsequent years may at least affect future incentive compensation awards and provide employees with positive incentives after a year of poor performance.*

Despite stock option plans and the recent growth of management incentive compensation plans, only a few empirical studies have focused on these plans' effects on corporate performance in the non-regulated sector. One early study of the compensation of the top three to five executives in 39 electronics, aerospace, and chemical companies found that firms which offered their executives financial rewards that closely paralleled shareholders' interests (e.g., stock options) exhibited better stock market performance during the 1947-1966 period than firms which offered bonuses that were simply paid out of earnings.** A more recent study of 50 large manufacturing firms found some evidence that firms which adopt performance compensation plans exhibit a significant growth in their capital expenditures (relative to non-adopting firms) and a favorable security market reaction to the announcement of the plan's adoption. The latter result suggests that the stock market perceives that such incentive compensation

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* For a description of a utility-sponsored incentive program of this type, see the discussion of Utility C in Appendix G.

** Masson, R. "Executive Motivations, Earnings, and Consequent Performance." Journal of Political Economy, November/December 1971, pp. 1278-1293.

plans have the desired incentive effects on both management and corporate performance.*

In formulating our recommended RCIP, we also reviewed several incentive compensation plans that have been recently implemented by electric utilities (see Appendix G). The use of such plans in the regulated utility industry is not widespread. For example, only 13 of 106 electric and gas utilities included in a 1979 survey reported that their top executives were covered by an incentive compensation plan.** However, recent interest on the part of utilities in incentive compensation plans, as indicated by the programs described in Appendix G, suggests that the incentive mechanism in our recommended RCIP should be an effective way to encourage utility managers to pursue performance improvements in an aggressive, yet cost-effective manner.

The Link Between Rate Performance and Management Incentive Compensation

As the next step in formulating the RCIP, we developed a procedure to link a utility's rate performance to the payment and distribution of an incentive payment award funded by ratepayers. Under this procedure, a utility whose rate performance as measured by its RPI would receive an incentive award payment. The firm, in turn, would distribute the award among its key managers. As we recommended earlier, the FERC should not be directly involved in the selection of the managers who will participate in a firm's incentive compensation plan. In addition, we recommend that FERC not be involved in determining potential and actual incentive award payments to individual managers within a firm. However, because we recommend that consumers bear the cost of such payments under the RCIP, FERC must be directly involved in setting the aggregate level of potential and actual incentive award payments to a utility under the RCIP.

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* Larken, D. F. "The Association Between Performance Plan Adoption and Corporate Capital Investment." (Mimeo.) Northwestern University Graduate School of Management, August 1981.

** Fox, Harland. Top Executive Compensation. A Research Report from The Conference Board, Report #793, 1980, Chapter 5, pp. 47-50.

We recommend that the aggregate level of an incentive award payment to a utility covered by the RCIP be set at 35 percent of the sum of the base salaries (excluding bonus compensation) for those executives whose base salaries are in the top 0.5 percent of all salaries paid by the firm.* Further, we recommend that FERC adopt a procedure that eliminates the need for the Commission to know any salary or bonus award information about an individual RCIP participant. Thus, the only information FERC would need from a utility covered by the RCIP is the aggregate base salary figure for these highest-paid executives. To avoid creating an incentive for a firm to raise its top base salaries in the first or subsequent years of the RCIP, we also recommend that in the initial year of the program, a firm's aggregate base salary figure be set equal to the aggregate base salaries of these executives in the preceding year, adjusted for inflation by the consumer price index for the region in which the firm operates. In each year after the initial year of the program, a firm's aggregate base salary figure would be set in an identical manner.

To evaluate the potential dollar magnitude of this recommendation for the determination of a firm's aggregate potential incentive award payment, we examined 1981 salary and revenue sales data for six utilities in New York.** Specifically, we attempted to determine the increase in each utility's retail and wholesale rates that would be required to recover the aggregate incentive award payment described above.+

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* In a 1979 survey of electric and gas utilities with incentive compensation plans, bonus awards to plan participants ranged from two to 40 percent of a participant's base salary, with a median award equal to 16 percent of base salary and a mid-range of 10 to 32 percent of base salaries. See: Fox. op. cit.

** All of the salary, sales, and revenue data were provided directly to us by the utilities.

\+ We also attempted to determine whether we could define a strong statistical relationship between salaries for top-paid executives and a utility's kWh sales, customers served, and revenues. Such a relationship might have served as a substitute for our 35 percent formula. However, the statistical relationships that were estimated were not strong enough to convince us to abandon the 35 percent formula.

The results of our analyses are shown in Exhibit 4.1. In 1981, the average salary of the highest-paid executives in the surveyed firms ranged from $64,815 to $83,823. If an incentive award payment had been made to each of these six firms in 1981 based on our 35 percent formula, the before-tax increase in retail rates necessary to cover these payments would have ranged from 0.04 to 0.11 mills per kWh, while the required before-tax increase in wholesale rates would have ranged from 0.08 to 1.08 mills per kWh. If the incentive award payments had been recovered from both retail and wholesale customer rates, the average before-tax rate increase necessary to cover the award payments would have ranged from 0.03 to approximately 0.10 mills per kWh. The after-tax rate increase required to recover the incentive award payments would be equal to the before-tax increases divided by the quantity, one minus the firm's marginal tax rate. On either tax basis, it can be seen that the required rate increases in general would be relatively small. However, in selected cases (e.g., Long Island Lighting Company), recovering the award payments only through wholesale rate increases might have been unacceptable: such a procedure might have required a 2 mill per kWh increase in the company's wholesale rates in 1981. (This analysis ignores any cost-reducing innovation that might have been effected by a firm's managers in response to potential incentive award payments. It also assumes that the firm would have actually received the maximum incentive payment which, as we discuss below, would not have occurred unless the firm had achieved an RPI equal to +1 during 1981.)

The recommended 35 percent formula determines the <u>aggregate</u> potential incentive payment award to each firm covered by the RCIP. To determine the <u>actual</u> incentive award payment that a firm would receive in a given year, the firm's aggregate potential incentive payment award is multiplied by the firm's RPI for that year.

Thus, if a firm's RPI in 1981 had been 0.7 and its aggregate potential incentive payment had been $300,000, the firm would have received an actual incentive award payment of $210,000. Under the proposed distribution scheme, the firm would have been allowed to distribute this award among its RCIP participants in a manner determined by the firm's board of directors and executive compensation committee.

Exhibit 4.1

SELECTED COMPARATIVE STATISTICS FOR NEW YORK STATE UTILITIES--BASED ON 1981 DATA

	Consolidated Edison Company of New York, Inc.	Niagara Mohawk Power Corp.	Long Island Lighting Company	Rochester Gas & Electric Corp.	Orange & Rockland Utilities, Inc.	Central Hudson Gas & Electric Corp.
Employees	23,000	9,900	5,777	2,800	1,691	1,345
Number of Highest-Paid Employees (Top 5% of Employees)	115	50	29	14	8	7
Combined Salaries of Highest-Paid Employees	$ 8,455,438	$ 3,324,163	$ 2,430,867	$1,118,832	$ 602,225	$ 453,704
Average Salary	$ 73,526	$ 67,840	$ 83,823	$ 79,917	$ 75,278	$ 64,815
Average Annual Customers	2,730,999	1,345,017	907,461	287,830	152,765	213,051
MWh Sales						
Total	30,302,189	32,127,631	13,402,973	6,685,707	3,511,511	5,522,260
Retail	27,189,822	29,398,292	12,615,592	5,314,630	2,061,743	3,428,767
Wholesale	3,112,367	2,729,339	787,381	1,371,077	1,449,768	2,093,493
Average Revenues (mills/kWh)						
Total Sales	126.25	52.29	104.78	56.03	90.77	72.14
Retail Sales	133.52	53.14	107.33	60.27	97.46	83.72
Wholesale Sales	62.71	44.15	64.05	39.61	55.36	53.18
Incentive Payment Cost (mills/kWh)*						
Total Sales	0.098	0.036	0.063	0.059	0.060	0.029
Retail Sales	0.109	0.040	0.067	0.074	0.102	0.046
Wholesale Sales	0.951	0.426	1.081	0.286	0.145	0.076
Incentive Payments ÷ Total Sales Revenues (%)	0.077	0.069	0.061	0.105	0.066	0.040

* (0.35)(Combined Salaries) ÷ kWh Sales

To earn an award under the RCIP, a firm must perform better than the average utility in its group. In addition, firms that have negative RPIs in a year will not receive any incentive payment award. Furthermore, we recommend that negative RPIs be cumulated for a firm to encourage continuous performance improvements. For example, without the cumulation of negative RPIs, the total aggregate incentive award payments to the firm over a five-year period would be identical (30 percent of the aggregate potential awards) under either of the two streams of RPIs shown below.

RPI VALUE STREAMS WITHOUT NEGATIVE CUMULATION

Year	RPI Value	RPI Value
1	0.00	0.00
2	0.15	0.05
3	-0.20	0.07
4	0.15	0.08
5	-0.10	0.10
Sum of Positive RPIs	0.30	0.30

However, the objective of the RCIP is to encourage continuous performance improvements over the long-term, as indicated by the second column of RPI values in the above table. Therefore, the cumulation of negative RPI values is required to provide this incentive.

With the cumulation of negative RPI values, a firm will not receive an incentive award payment unless its positive RPI value in a given year exceeds the absolute value of the negative RPI values the firm has earned since it last received an incentive award payment. Furthermore, in any year in which the firm's positive RPI value exceeds the absolute value of the sum of its negative RPI values, the firm will earn an incentive award in that year based only on the difference between its positive RPI value and the absolute value of the sum of its negative RPI values. Under this scheme, for example, a firm with the RPI values shown in the first column of the table above would receive an incentive award payment only in Year 2. At the end of Year 5, the firm would have a cumulative negative RPI value of -0.15 (i.e., the sum of -0.20, +0.15, and -0.10). If the firm's RPI value in Year 6 were 0.20, the firm's aggregate incentive award payment would be equal to 0.05 (i.e., the sum of 0.20 and -0.15) times the firm's aggregate potential incentive award in Year 6.

Although we recommend the cumulation of negative RPI values to provide an incentive for continuous performance improvements, we also recognize that a firm that earns a series of negative RPI values over a four- or five-year period may be unable to earn an incentive award payment for many years. Such a situation would provide managers with little incentive to improve their firm's performance. Therefore, we recommend that negative RPI values be cumulated over the last three years only. That is, each year, the fourth preceding year's negative award (if present) would be eliminated from the deficit account. Management would then not have more than three years of poor performance to work off before a positive award could be earned; thus, the executive compensation plan would have real incentive value at all times.

IMPLEMENTATION ISSUES

In addition to the structural issues for the RCIP discussed in the preceding sections, FERC will also have to address three major implementation issues if it decides to proceed with the RCIP. Specifically, the Commission will have to resolve four major issues:

1. Which utilities should participate in the program?

2. How should utilities be grouped?

3. How should the cost of incentive award payments under the RCIP be recovered?

4. What types of compliance reporting measures should be required for firms covered by the RCIP?

Program Participation

We recommend that all electric utilities regulated by FERC be included in the RCIP, but that participation by individual utilities be on a voluntary basis. Specifically, FERC should take no direct punitive action against a firm that refuses to implement a ratepayer-funded incentive compensation program for its managers under the RCIP.

However, for evaluation purposes, each utility regulated by FERC should be assigned to a comparable group using the grouping techniques described in Chapter 3. By grouping its regulated utilities, the intragroup performance of utilities with and without incentive compensation programs can be measured and compared. If these measurements and comparisons indicate that the utilities covered by the RCIP systematically perform better than non-participating utilities, then FERC might elect in rate cases to adjust downward the allowed return on equity, and thereby the electricity rates, of firms that refuse to participate. The Commission could announce the specific reason for these adjustments in the rate case orders for these firms.

In general, we recommend against such rate-of-return adjustments. However, if a firm continues to perform poorly relative to a group of comparable utilities and refuses to take steps to encourage its managers to improve the firm's performance, then regulators have no choice but to protect the interests of ratepayers and to point out this poor performance to the firm's shareholders and hope that the shareholders, through the firm's board of directors, will effect the necessary management changes.

Utility Grouping Technique

Probably the most controversial aspect of the recommended RCIP is the requirement that each utility be assigned to a group of comparable utilities. In Chapter 2, we recommend that FERC undertake a comparable grouping rulemaking for all Class A and B utilities, and permit all the utilities and other interested parties (e.g., consumer advocate groups) to submit testimony. The initial proposed rulemaking could include a staff proposal concerning potential grouping techniques.

As we also indicated in Chapter 2, the grouping of similar utilities should be based on the attributes of a utility's environment which are deemed outside its control but affect its cost of service. This may result in groupings which exhibit substantial within-group variance in their average revenues per kWh due to different responses by utilities in the past to similar enviornmental influences. While we have already articulated several reasons for not considering any firm-specific attributes in grouping utilities (such as percent of generating capacity that is coal-fired), we do note that another factor which could account for within-group variance is that a utility's external environment may change over time. This could result in the reference group for a given firm changing through time as well as some of the within-group variance observed at any particular point in time. That is, current differences may reflect past differences in operating environment rather than the quality of past decisions. This, of course, is testable; if it can be demonstrated that this phenomenon is material, then FERC may choose to consider some firm-specific attributes in addition to environmental attributes in its grouping of firms. Nevertheless, we advise against grouping on the basis of firm-specific attributes unless it is clearly warranted.

Recovery of the Costs of Incentive Award Payments

The issue of how the cost of incentive award payments should be recovered from consumers contains two elements. The first concerns the specific rates to which a rate surcharge should be applied to cover the cost of the aggregate incentive award payment to a firm in a given year. The second element deals with the determination and collection of the rate surcharge.

With respect to the first element, the cost of incentive payment awards to a firm can be borne by the firm's wholesale customers only or by its wholesale and retail customers jointly. Three problems arise if the cost of incentive payment awards are borne entirely by wholesale customers. First, if wholesale customers bear the entire cost, the rate performance measures used to develop the RPI values for firms should be based only on wholesale rate levels. In this situation, utilities will have an incentive to try to allocate as much of their cost of service as possible to retail jurisdictions in order to minimize their wholesale rates. Second, because wholesale service is typically only a small fraction of a utility's total production, the increase in wholesale rates necessary to fund the award payments might raise wholesale rates to an unacceptable level. Third, it is unlikely that wholesale customers would fail to challenge the legality of recovering the total cost of a program which is jointly sponsored by FERC and its regulated utilities from a single group of customers. Moreover, such challenges would probably be upheld under judicial review.

Because of the problems described above, we recommend that the cost of incentive award payments to a utility be recovered from the firm's retail and wholesale customers. However, FERC cannot guarantee that state regulatory commissions will mandate that retail customers absorb their fair share of the cost of such award payments (even though they will benefit from their utility's performance improvements). We thus recommend that FERC work closely with state regulatory commissions to ensure that these commissions will agree to flow through a fair share of the incentive award payments to retail customers. If retail customers do not absorb their share and the resulting award payments are borne by wholesale customers, the award payments will be relatively small and their potential incentive effects will be reduced. Thus, joint cooperation and participation by state regulatory commissions in the RCIP is essential to the success of the program.

With respect to the second element, we recommend that a rate surcharge be put into effect on January 1 of the performance year. This surcharge would be sufficient to recover a firm's aggregate potential incentive award payment and would be levied on all kWh sales reflected in the accounts included in the denominator of the aggregate cost measure (see Chapter 2). Revenues from this surcharge would be held in escrow during the performance year. In January of the following year, the firm's actual incentive award payment will be determined and the award payment, if any, would be made by February 1. If the escrow account exceeds the actual incentive award payment (an event that will probably occur) or no award is made, the surcharge for that year would be adjusted downward to reflect the excess cost recovery. This process would be repeated each year. Because we have been unable to obtain a consistent legal interpretation of whether the surcharge revenues could be collected on a tax-free basis, we are unable to say whether the surcharge would be set on a before- or after-tax basis. FERC will have to obtain a ruling from the Internal Revenue Service on this matter.

Compliance Reporting Under the RCIP

FERC's involvement (and possibly that of state regulatory commissions in concert with FERC) in the incentive compensation plans of firms covered by the RCIP and in reporting requirements for utilities participating in the program should be minimized. Therefore, we recommend that each utility covered by the RCIP submit a brief written description of its incentive compensation plan to FERC each year. This description would summarize the performance objectives covered by the plan, the number and types of employees participating in the plan, major changes in the plan from the previous year's report, and the sum of the annual base salaries of executives whose salaries are in the top 0.5 percent of all salaries paid by the firm. In addition, this annual report should indicate the average bonus award and the number of RCIP participants who received bonus awards distributed from an incentive award payment (if any) made to the firm for the reporting year.

Firms which refuse to participate in the RCIP should also be required to report to FERC annually and indicate whether they had an incentive compensation plan in effect during the reporting year. This information would be useful in conducting statistical analyses to determine whether non-RCIP participants that have incentive compensation plans perform better, on average, than comparable non-participants who do not have such plans.

5 ADDITIONAL INCENTIVE PROGRAM POSSIBILITIES

In the previous chapter, we described a comprehensive program for promoting efficient operations and cost-minimization in the electric utility industry. Overall, we believe this program comes as close as possible to meeting our selection criteria for an incentive program. Accordingly, we recommend that FERC and the state commissions consider this program for implementation.

In this chapter, we describe and evaluate two additional programs that meet our selection criteria in varying degrees. The first program is a construction cost control 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 the rate base. This program is supplementary to the program outlined in Chapter 4 and is meant to strengthen the incentive for firms to control the cost of power plant construction. We recommend that FERC and state commissions consider it for adoption.

The second program is an automatic rate adjustment program which is based on changes in the prices of a utility's production inputs. By lengthening the period between formal rate cases, this program is meant to simulate for an extended period, the circumstances of a competitive market in which a firm cannot influence the price it receives for its products. As a result, firms should have a greater opportunity and incentive (than in the conventional regulatory framework) to minimize their short- and long-run production costs, and to reap the additional profits associated with these actions. Although we believe this program has merit, because of certain weaknesses, we do not support it as strongly as the incentive compensation-oriented program. Nevertheless, recognizing that some commissions or firms may not be receptive to the incentive compensation-based program, we offer the automatic rate adjustment program as a possible alternative.

CONSTRUCTION COST CONTROL INCENTIVE SYSTEMS FOR LARGE-SCALE PROJECTS

Until recently, none of the proposed incentive systems for promoting efficiency in electric and gas utilities have focused explicitly on controlling the costs of major plant construction projects (e.g., pipelines, large fossil or nuclear electric plants, synthetic gas plants). Yet these construction costs comprise a large part of the rate base upon which utility tariffs are based.* Two factors complicate the construction of large-scale projects and, hence, the rate base: such projects tend to exhibit "cost growth" as they are being built (i.e., a continual upward revision of the cost of a project as its design becomes more detailed) and pure cost overruns at the time construction is completed. Exhibit 5.1 depicts the cost growth and overrun experience of a number of such projects. As shown in this exhibit, the completed cost of each project was double to triple its initial cost estimate. Even after adjusting for unanticipated inflation and changes in the project's scope, the completed cost of each averaged more than 100 percent over its initial estimated cost.

To encourage private firms to undertake equity sponsorship for such projects and finance them in conventional capital markets, it is necessary to ensure that the project will be economically viable and that provisions are made for cost overrun financing before construction begins. In the context of a regulated utility, this means the

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* Two large-scale construction projects have recently been subjected to regulatory incentive systems. These projects--the Alaska Natural Gas Transportation System (ANGTS) and the Nine-Mile Point No. 2 nuclear station--are reviewed and evaluated in Appendix H.

Exhibit 5.1

COST OVERRUNS IN MAJOR CONSTRUCTION PROJECTS COMPLETED BETWEEN 1956 and 1977

Project	Initial Estimate: Amount (millions)	Initial Estimate: Date	Actual Result: Amount (millions)	Date Completed	Ratio of Final to Initial Cost: Unadjusted	Ratio of Final to Initial Costs: Adjusted — For Unanticipated Inflation	Ratio of Final to Initial Costs: Adjusted — For Change in Scope of Project	Compound Annual Rate of Cost Overruns, after Adjustments (percent)
1. Bay Area Rapid Transit Authority	$996.0	1962	$1640.0	1976	1.647	1.297	1.037	0.31
2. New Orleans Superdome	46.0	1967	178.0	1975	3.870	3.219	3.219	15.73
3. Toledo Edison's Davis-Besse nuclear power plant, Ohio	305.7	1971	466.0	1975	1.524	1.401	1.401	11.89
4. Trans-Alaska Oil Pipeline (Alyeska)	900.0[b]	1970	7700.0[c]	1977	8.556[c]	6.926	4.250	22.96
5. Cooper Nuclear Station, Nebr. Pub. Power Dist.	184.0	1966	395.3	1974	2.148	1.748	1.748	7.23
6. Rancho Seco Nuclear Unit No. 1, Sacremento	142.5	1967	347.0	1974	2.435	2.026	1.239	3.11
7. Dulles Airport, Washington, D.C.	66.0[c]	1959	108.3[c]	1962	1.641[c]	1.641[d]	1.486	14.10
8. Second Chesapeake Bay Bridge	96.6[c]	1968	120.1[c]	1973	1.243[c]	1.104	1.104	2.00
9. Frying Pan Arkansas Project Ruedi Dam	12.8[c]	1962	22.9	1972	1.789[c]	1.636	1.145	1.36
10. Frying Pan Arkansas (Sugar Lo[illegible]	6.1[c]	1962[c]	10.2	1973	1.672[c]	1.500	1.500	3.75
11. Frying Pan Arkansas (Boustead Tunnel)	[illegible].2[c]	1962	21.2[c]	1973	2.304[c]	2.078	1.233	1.92
12. Rayburn Office Building, Washington, D.C.	6[illegible].0[c]	1956	98.0[c]	1966	1.531[c]	1.531[d]	1.342	2.99
Weighted Average[a]					3.93	3.21	2.21	10.07

[a] The compound annual rate expression is used only as a convenient method of comparing initial cost estimates with the sum of all actual costs at the termination of the project. This device permits a comparison of overruns on several projects having different construction periods.

[b] In May 1974, the Alyeska Pipeline Service Co. re-estimated capital cost at $4 billion. In October 1974, costs were estimated at $6 billion for the completed pipeline. By June 1975, the cost estimate was raised to $6.375 billion. In 1969, the $900 million cost estimate for Alyeska assumed a capacity of 500 mb/d. The scope was changed to permit a capacity of 1,2 million b/d. The cost of this change in scope was $700 million, raising the initial capital cost estimate to $1.6 billion.

[c] Does not include interest.

[d] Observed inflation was less than anticipated.

SOURCE: Mead, Walter J. Transporting Natural Gas from the Arctic, Washington, D,C.; American Enterprise Institute, 1977, Table 1.

regulators must *a priori* commit consumers to pay the full cost of the project regardless of its final construction cost.*

Thus, a regulatory commission faces a difficult decision in approving a large-scale project. The commission must commit consumers to pay for the project regardless of its final cost,** even though this cost is highly uncertain and often estimated too conservatively. An incentive system designed to contain costs can be considered as a counterbalance to the full cost-of-service tariff that must be allowed to enable a project's sponsors to recover its total cost.

A properly designed and clearly established construction cost control incentive system can achieve two objectives. First, it can work to ensure that the project's sponsors properly plan and control the proposed project, especially by providing adequate control-warning systems and contingency plans to avoid the most costly causes of major cost overruns.+ Such an incentive system promotes activities

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* The one generally accepted exception to the recovery of full cost is in the case of demonstrated imprudent outlays or management. Needless to say, such demonstrations are difficult to make.

** The commitments are often implicit rather than explicit. In many jurisdictions, the commission must pass judgment prior to construction on one or more issues such as siting, environmental impacts, financing, and/or the project itself (through a certificate of public convenience and necessity). All of these provide some legal basis for implicit or explicit approval of the project and a commitment to full-cost recovery.

\+ A 1978 report by the General Accounting Office entitled *Lessons Learned from Constructing the Trans-Alaska Oil Pipeline* indicated that one of the major problems experienced on the Trans-Alaska Pipeline System was the lack of adequate control systems. These systems are necessary for the rapid collection and reporting of relevant data to enable project management to identify problems and instruct the proper field personnel to take corrective action on a timely basis. However, these systems were not in place until well after construction began and were too slow and inadequate.

which tend to anticipate problems and reward good performance, rather than simply penalizing imprudent or poor performance.

Second, if the regulatory body clearly states at the outset of its proceedings that the cost estimates provided by the project's sponsor will be the base upon which subsequent performance will be measured and a reward or penalty given, then the incentive system also becomes a vehicle to ensure that the sponsor is providing the best, unbiased, estimate of what the project will actually cost. Such an assurance would be extremely valuable to regulatory bodies that lack expertise in cost estimation. Additionally, it would counter the bias to promote capital projects when excess returns are being allowed (i.e., the Averch-Johnson effect). However, this is probably not a problem in the electric utility industry today, although it may have occurred in the late-1960s and early-1970s before high interest and inflation rates eliminated potential gains from excess capital substitution.

We recommend that FERC consider implementing a construction cost control incentive program that incorporates an incentive rate of return (IROR). On the basis of our review of several existing programs, an analysis of the conceptual issues underlying such programs, and an evaluation of this type of incentive program relative to the criteria discussed in Chapter 2, we conclude that a properly designed and implemented construction cost control incentive program, coupled with a mangement incentive compensation program (see Chapter 4) is an effective way of efficiently controlling electricity costs over the long-run without unfairly penalizing a utility's stockholders. A construction cost control incentive program that is not linked to a management incentive compensation program will be less effective in promoting efficient, long-term planning decisions and the short-term managerial control of construction costs.

In the following sections, we discuss several questions that should be carefully considered in developing a construction cost control incentive program. We then describe our recommended program and detail steps that FERC might take to implement it.

Consideration in Designing a Construction Cost Control Incentive Program

Four major questions should be carefully considered when a regulatory body is deciding whether a construction cost control incentive program should be undertaken. These questions are:

1. What are the potential costs of the program?
2. How should a utility's performance in estimating and controlling its construction costs be measured?
3. How should the incentive rate of return be determined?
4. What types of ratemaking adjustments might be necessary at the completion of the construction project?

We discuss each question below.

Potential Costs of an Incentive System. The major potential cost of a construction cost control incentive system is the cost of a higher rate of return that may be required by investors who purchase debt issued by a utility covered by the system. In particular, because the investment community has not been very receptive to incentive systems, their negative attitude may impose some extra costs on the customers of a utility participating in an incentive system. For example, Moody's Investor Service* recently lowered the bond ratings of one utility that is sponsoring the construction of a nuclear power plant which had a recently imposed incentive rate of return plan. In this instance, the higher debt cost effect spilled over, not only to debt directly associated with the nuclear project, but also to the utility's total outstanding debt.

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* Moody's Investor Service. "Impact of a Recent NYPSC Order on Some New York State Electric Utilities." Moody's Bond Survey, May 17, 1982, pp. 2042-43.

One possible explanation for this effect lies in the investment community's extensive reliance on the simple coverage ratio statistic to judge the quality of the utility's debt. For example, consider a utility that makes a billion dollar investment financed equally by debt and equity at costs of 16 percent and 18 percent, respectively. The utility has a 40 percent marginal tax rate. If the project were completed for one billion dollars, the coverage ratio at the outset of the project's operations would be 2.875X, as shown below:

$$\text{Coverage Ratio} = \frac{\text{interest + return on equity + taxes}}{\text{interest}}$$

$$= \frac{80 + 90 + 60}{80} = 2.875X$$

Now suppose a 40 percent cost overrun occurs. If the cost overrun were financed in some way and at the same initial investment, the coverage ratio on the total debt would remain unchanged. But, if the allowed after-tax return on equity were reduced from 18 to 15 percent as a result of an incentive scheme, then the coverage ratio would fall to 2.5625X, as shown below:

$$\text{Coverage Ratio} = \frac{112 + 105 + 70}{112} = 2.562X\ .$$

In this case, using the simple coverage ratio statistic, the debt appears to be more risky under the incentive scheme. However, under the incentive scheme, there is no risk that cash flows will be insufficient to service the project debt, because the incentive system affects only the return on equity and does not affect either the return on the debt or the return of capital (i.e., depreciation).

It could be argued that another cost of an incentive system on major project construction would be the bias it creates on management's part. Specifically, knowing that an incentive system would be imposed might make management averse to riskier projects and technologies. However, so long as regulatory authorities are willing to set an average return that is sufficient to compensate the project's equity suppliers for their perceived risk, this poses no great problem. For any economically sound project, an incentive system should provide a risk premium sufficient to make the project attractive to equity investors. In fact, the process of explicitly dealing with setting the risk premium will make regulatory authorities aware of the potential benefits and costs of alternate technologies and strategies. So, if regulators are prepared to allow high average returns for projects with large uncertainties regarding their completed cost, there should be no inherent bias away from risky projects under an equity return incentive system.

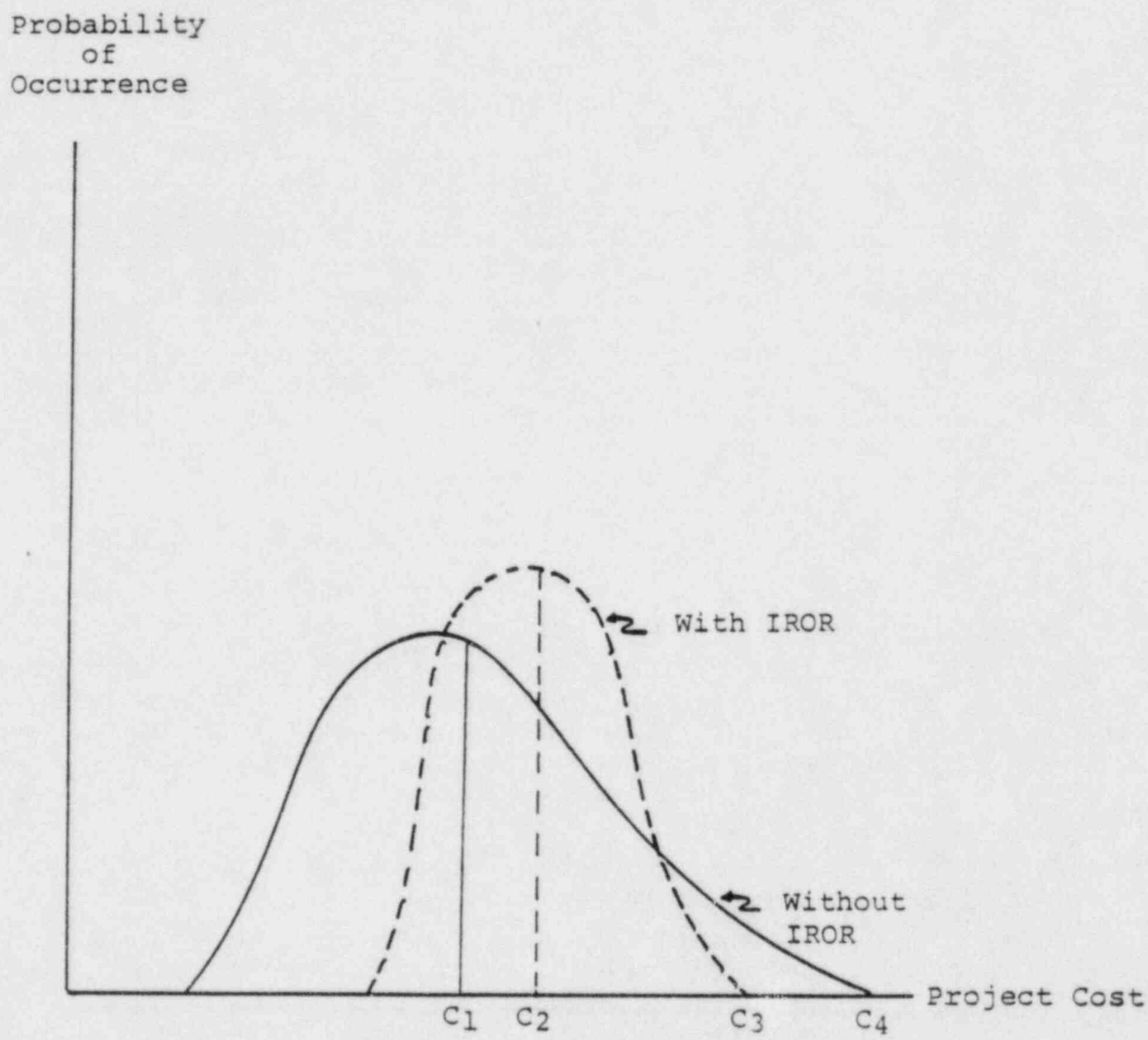
Cost control systems themselves are not costless, and will have to be paid for by the utility's customers. For example, a risk premium on equity may be allowed to compensate for the risk of the incentive system. (This element will be discussed later.) Also, depending on the complexity of the system, its administrative costs may be substantial. However, the benefit obtained by incurring these added costs is a reduction in the variance of the project's final cost, especially the variance in that portion of the cost distribution associated with cost overruns, as depicted in Exhibit 5.2. Achieving a lower expected completion cost under the incentive system is certainly possible and desirable. However, from the customer's perspective, the imposition of an incentive system that reduces the risk of large cost overruns (i.e., $C_3 - C_2$ is less than $C_4 - C_1$ in Exhibit 5.2) could be perceived as desirable even if it does not reduce expected cost (i.e., C_2 is greater than C_1). Thus, the cost control objective of an incentive program could be considered a success even if the expected value of the cost of the project were to increase.

Measuring Cost Performance. There are two essential components to an incentive rate of return plan. The first is a measure of cost performance; the second is a rate of return on equity schedule (discussed in the next section). The IROR component that measures cost performance is called the cost performance ratio (CPR), which is the ratio of actual capital costs (A) to projected capital costs (P):

$$(1) \quad CPR = \frac{A}{P}.$$

Exhibit 5.2

SUBJECTIVE PROBABILITY DISTRIBUTIONS WITH AND WITHOUT AN IROR PROGRAM



To ensure that the plan does not penalize a participant's equity investors for factors that are clearly outside management control, either the numerator or the denominator must be adjusted for these factors. Two major categories of "uncontrollable" items are inflation and changes in a project's scope.* The first category certainly lies outside management control, being largely a function of monetary policy and aggregate demand/supply relations in various markets.

In estimating a project's initial CPR (i.e., the CPR estimated before the project is started), inflation can be addressed by requiring the project's sponsor to submit the project's projected capital costs (PCC) expressed in constant dollars and broken down into several cost categories by time period (e.g., three-month periods), with price indexes for each category.** The second category can be handled by specifying an explicit set of "triggering events" that qualify for scope change consideration. A procedure can also be specified to consider scope change claims by the sponsor and adjust the PCC when deemed reasonable.+

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* Consideration should also be given to construction delays outside management control that increase the project's CPR. However, this is done through the traditional allowance for funds used during construction (AFUDC), which adds to the actual capital costs (A) if a project's completion is delayed.

** In the ANGTS case, for example, 25 cost categories were identified (see Appendix H).

\+ In the ANGTS case, five events were specified: war, an emergency or major disaster determined by the President, design changes required by law, major changes in routing or capacity ordered by the government, and delays in the receipt of governmental permits. A new federal office set up under a limited governmental reorganization, Office of the Federal Inspector, ANGTS, is responsible for most matters between the project and the government. Although FERC is responsible for the system tariff, including the IROR, it has delegated to the Federal Inspector the authority to recompute the PCC in the event of a scope change finding.

In calculating a project's final CPR (i.e., the CPR estimated upon completion of a project), a choice must also be made to use either constant or current dollars (and, correspondingly, a real or nominal AFUDC rate) in the final determination of the numerator (A) and denominator (P). Because the consumer's cost of service is affected by inflation, the appropriate choice is current dollars.*

If we let:

- X_{it} denote real (base period) dollar projected capital outlays in cost category i in time period t, adjusted for allowed scope changes;
- N denote the number of cost categories;
- P_{it} denote the actual price index of cost category i in period t (equal to 1.00 in the base period);
- R denote the projected AFUDC rate over the construction period (usually set as a weighted average cost of projected debt and equity capital);
- C_t denote the actual capital outlays in time period t;
- T denote the actual time to completion; and
- T' denote the projected time to completion (adjusted, if necessary, to reflect scope changes);

then once construction is completed, the actual and predicted capital costs which are used to determine the project's final CPR can be expressed as:

$$(2) \quad A = \sum_{t=1}^{T} C_t (1+R)^t$$

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* FERC chose to utilize constant dollars in its CPR calculation for ANGTS, employing a real AFUDC rate of five percent. This requires deflating actual expenditures by cost category. Hence, actual outlays must be clearly accounted. Using the current dollars approach does not require accounting for actual outlays by cost category and appears to be less controversial and burdensome.

$$(3)\quad P = \sum_{i=1}^{N} \sum_{t=1}^{T'} X_{it} P_{it} (1+R)^{t}.$$

<u>Incentive Rate of Return Schedule</u>. The second component of the cost performance measure is the incentive rate of return schedule. This schedule represents the relationship between the project-specific return on equity a utility will be allowed to earn after a construction project has been completed and the utility's CPR for the completed project. The project-specific allowed rate of return on equity r is comprised of two elements. The first element is the base rate of return k that the utility will be allowed to earn on the ratio of the project's projected costs P to its completed costs A. The second element is the rate of return r_m that the utility will be allowed to earn on the dollar value of deviations in actual completed construction costs (A) from projected costs (P). Because the overall allowed return r depends on how well the utility estimates and controls its construction costs, r is called an incentive rate of return (IROR). The relationship between the incentive rate of return and the CPR of a project can be expressed mathematically as:

$$r = k\left(\frac{1}{CPR}\right) + r_m\left(1 - \frac{1}{CPR}\right).$$

This expression is equivalent to:

$$(4)\quad r = k\left(\frac{P}{A}\right) + r_m\left(\frac{A - P}{A}\right).$$

As shown by equation (4), the incentive rate of return r increases as the ratio of actual to projected costs decreases. If actual costs equal projected costs (i.e., CPR = one), the utility's incentive return is equal to the base return k. If actual costs exceed projected costs (i.e., CPR is greater than one), the utility earns an incentive return less than k. In fact, the incentive return r approaches r_m as the project's CPR approaches infinity. Conversely, if actual costs are less than projected costs, the utility earns a higher incentive return. Because the rate of return on the dollar value of deviations in A from P (i.e., r_m) is set at a value less than k, the utility has an incentive to minimize the CPR of its project. In fact, the incentive return r approaches infinity as the project's CPR approaches zero. These relationships are depicted in Exhibit 5.3.

Under an IROR program, the values of the parameters k and r_m are set by the regulatory body and the utility supplies its projected cost estimates P. Because these three parameters (k, r_m, and P) are fixed, the utility clearly understands that it will earn an average return of k on P and a lower return r_m on the dollar value of deviations A from P. For example, in the first year of a project's commercial operation, the dollar return R that the utility will earn on the project investment equals the rate base (i.e., completed costs A) times the allowed return r, i.e.,:

$$R = A \cdot r$$

$$R = A \cdot \left[k \left(\frac{P}{A}\right) + r_m \left(\frac{A-P}{A}\right)\right]$$

$$(5)\quad R = k \cdot P + r_m(A-P).$$

As shown in equation (5), the utility's dollar return in the first year equals the base return k times projected costs P plus the return r_m times the difference between actual and projected costs for construction. If A exceeds P, the utility will earn a higher dollar return but a lower average rate of return than it would earn if A is less than P. Thus, the utility's average rate of return is increased by keeping actual costs as low as possible.

The parameters for the IROR formula in equation (4) require some analysis before they can be set. The rate r_m must be set low enough so that there is a real incentive to avoid additional construction outlays. A value below the current rate on government bonds of comparable duration (the riskless rate) would be a reasonable upper limit.*

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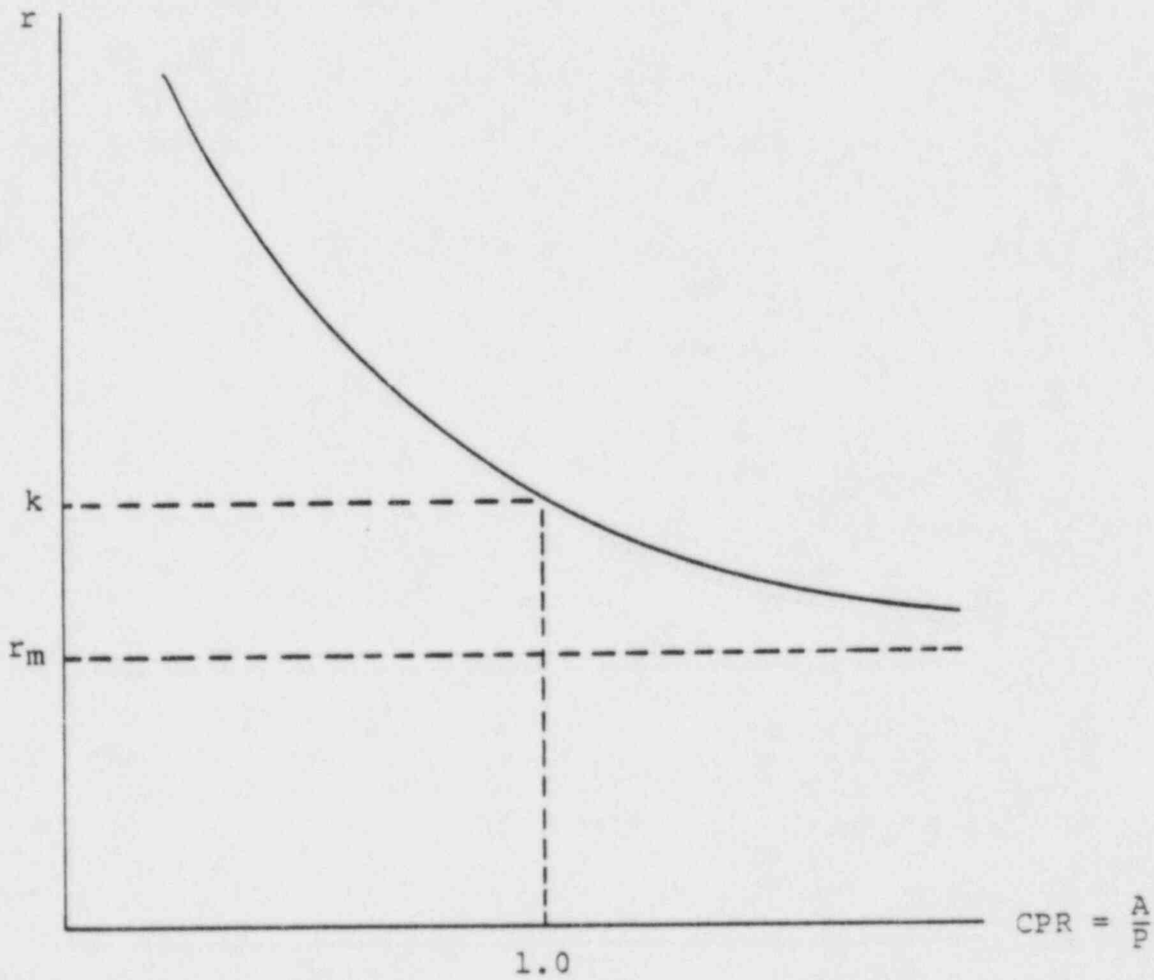
* If the lowest possible rate of return on an equity investment in the project is the government bond rate, the investment must be more attractive than government bonds.

Exhibit 5.3

IROR SCHEDULE



The parameter k, which is the base rate that would be earned if the actual cost performance equaled projected cost performance, is more difficult to set. It must be sufficiently high to make the investment attractive for equity investors, in spite of a low rate r_m. The level at which k is set should reflect at least three risk premiums. The first is a risk premium associated with normal utility investments. The second is associated with the specific construction project (e.g., the risk premium associated with the construction of a nuclear generating unit may be higher than a risk premium for constructing a coal-fired unit). The third risk premium may be required by investors because an IROR program is being applied to the project. The levels of these risk premiums should depend on the extent to which the increased variance in the utility's earnings associated with each risk component can be diversified by investors. The greater the degree to which these risks can be diversified (i.e., the less systematic the risks), the lower the required premium on each of the three risk components. No formulas or set rules exist for determining k. However, general analyses of the potential effects on investors of different values for k and r_m can provide insights on how high k should be set.*

<u>One-Time Rate Base Adjustment</u>. Because the incentive rate of return is applicable to a specific project and not to the utility's total rate base, a one-time adjustment to the utility's rate base may be desirable to eliminate the need for separate accounting and ratemaking treatments of the utility's investments. That is, unless the only investment in the utility's rate base is the investment to which an IROR has been applied,** the regulatory commission must determine revenue requirements separately for those portions

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* For example, the value of k (given r_m) that results in an expected net present value of zero for equity investors is the value that could be set if investors were risk-neutral. However, investors are not risk-neutral. Therefore, this value of k might be interpreted as the minimum value of k required by investors.

** In this case, the incentive rate does not exist because the IROR is equivalent to a normal equity return that would typically be allowed by the regulatory commission on general utility investments.

of the utility's investments to which the IROR is applicable and those portions to which the normal, non-IROR equity return is applicable. To eliminate the need for segregated accounting and ratemaking treatments of the utility's rate base, the regulatory commission can simply make a one-time adjustment to the utility's total rate base. This adjustment will allow the regulatory commission to use the utility's normal equity rate of return in setting revenue requirements and, at the same time, allow the utility's equity investors to earn the incentive rate of return on that portion of the utility's rate base to which the incentive rate is applied.

To see how this works, consider an initial equity investment of one dollar that is returned over N years and allowed to earn an incentive rate r on the undepreciated balance. The cash flow CF in year t is:

$$CF_t = \frac{1}{N} + r\left(1 - \frac{t-1}{N}\right), \qquad t = 1,\ldots,N,$$

where the first term is the return of capital and the second term is the return on the undepreciated balance.

If the normal equity rate of return on conventional utility operations is i, then the present value M of the cash flows from the investment to which the incentive rate is applicable over the book life of that specific investment is:

$$(6) \quad M = \sum_{t=1}^{N} CF_t (1+i)^{-t} = \frac{B(N,i)}{N} + \frac{r}{i}\left[1 - \frac{B(N,i)}{N}\right]$$

where B(N,i) is the present value of one dollar per year for N years at rate i. Allowing the conventional equity rate of return i on M is equivalent (in present value terms) to allowing the incentive rate r on the initial equity investment of one dollar. If the incentive rate r is greater than the normal rate i, then M is greater than one; if r is less than i, then M is less than one. Thus, applying the multiplier M from equation (6) to the utility's conventionally determined rate base at the end of the project's construction embodies the incentive reward or penalty through a one-time adjustment to the utility's rate base. This is done so that the adjusted rate base can then be allowed a "normal" equity return thereafter.*

The following example demonstrates how the one-time rate base adjustment might work. Consider a utility that has an equity rate base of $2 billion to which a normal rate of return of 14.17 percent (i.e., i = 14.17 percent) is applicable. Suppose the utility has completed a project with a book life of 25 years and that an incentive rate of return of 18.07 percent is applicable to the equity portion of the project investment. Under these assumptions, the utility's conventional equity rate base of $2 billion would be adjusted upward by a factor of 1.20** to $2.4 billion (1.20 x $2 billion). Thus, equity capital suppliers would be indifferent, from a present value standpoint, to a normal equity return of 14.17 percent on the adjusted rate base of $2.4 billion and an incentive return of 18.07 percent on an unadjusted rate base of $ 2 billion.

The one-time rate base adjustment also minimizes the potential for a regulatory commission in later years to change an incentive rate of return that may appear high relative to normal equity returns in those years. Regulatory commissions are essentially political and social creatures, not economic creatures, and the people who serve as, and appoint members to, regulatory commissions change over time. Moreover, future members of a regulatory commission cannot be bound by the decision of the commission's current members. The use of the one-time rate base adjustment, however, would make it

* The conventional rate base is determined by applying the actual AFUDC rate (set on the basis of actual costs of debt and equity and the capital mix) to the actual outlays over the entire construction period.

** $M = \frac{6.80}{25} + \frac{.1807}{.1417} \left[1 - \frac{6.80}{25}\right] = 1.20.$

extremely difficult for a commission to remove the incentive return effects from a utility's rate base in the future.

Recommended Program

We recommend that FERC undertake a generic rulemaking to consider the implementation of a construction cost control incentive program. This program would incorporate an incentive rate of return mechanism and also link the compensation of construction project managers to a management incentive compensation program similar to that discussed in Chapter 4. Specifically, under our recommended program, an incentive rate of return would be applied to any large-scale construction project undertaken by an electric utility regulated by FERC. In addition, the salaries and bonuses of the key managerial personnel responsible for planning and implementing major projects in the utility would be tied to construction cost performance, as measured by something like the CPR.* If the key construction program managers are identified and if their potential bonuses constitute a significant fraction of their base salaries, such a system may elicit maximum managerial performance and achieve the proper cost controls.

Referring to Exhibit 5.2, either the management compensation incentive program or the IROR program alone could be used to reduce the variance in the probability distribution of the project's cost, although the reduction in the variance of the distribution of rates customers will pay over the project's life is greater under an incentive system based on return to equity. However, both incentive systems can be used simultaneously, as Sillin and Diamond suggest: "future rate policies might include linking executive compensation with construction and rate-of-return policies."** Given the importance of

* An incentive plan between the utility and its external contractors is not the issue here. Any such plan and its payoff or penalty would be considered in determining the CPR and rate base, exclusive of any IROR adjustments.

** Sillin, J. and Diamond, M. "A New Approach to Putting CWIP in the Rate Base." Utility Management Perspectives. New York: Booz-Allen & Hamilton, Spring-Summer 1982.

construction cost control in affecting long-term overall utility costs, the key executives responsible for the planning and execution of major construction projects should be participants in a management compensation incentive program. How the reward pool is set and shared should be left to the discretion of a utility's board of directors. For example, a utility might choose to link individual potential bonus awards to specific construction-related targets, one of which might include the CPR for a major project. However, to ensure that ratepayers are protected from major cost overruns that, to some degree, are under the control of utility management, FERC should implement the IROR and management incentive compensation programs simultaneously.

The additional cost of a management incentive compensation program linked to an IROR program is very small. For example, if a project came in below its projected cost, the potential bonus awards to construction managers would cost consumers in the aggregate virtually nothing, since the bonuses would be a very small percentage of the project's actual total cost. By the same token, if the project were to experience cost overruns, consumers would receive little protection from the rate impacts of the overruns as a result of the management compensation program (while management salaries would be penalized, the utility's rates would not be significantly affected by the reduction in the salaries of these few managers). However, consumers would be protected by the IROR program.

The implementation of a construction cost control incentive program by FERC might increase the commission's regulatory oversight workload. We use the term "might" because it is unclear whether FERC's workload under the program would be greater than the workload that is currently being imposed on the commission in a number of plant abandonment proceedings. Several utilities that have partially completed major generating plant construction projects have recently cancelled these projects for a variety of reasons. However, in each cancelled project, the projected costs of the plant's completion were significantly greater than the completion costs estimated at the time construction began. The enormous costs of these abandoned plants are typically passed on to ratepayers. In addition, the final costs of most plants that are being completed today are far above the initial projected costs for the plants. A construction cost control incentive program might minimize construction cost overruns and also ensure that construction is not begun on plants that are economically viable only under unrealistic or highly tentative demand and price assumptions.

The construction cost control incentive program for a specific utility project could be implemented by FERC in a series of six steps. This procedure would include a two-step preliminary approval stage, a two-step final approval stage, and a two-step IROR stage (see Exhibit 5.4).

The preliminary approval stage is necessary because it is unlikely that utilities can make highly accurate cost estimates at an early stage of project design. This is because most utilities would be unwilling to spend the large amount of money necessary to obtain accurate cost estimates, unconditionally bet their economic well-being on the estimates, and then assume that FERC and the regulatory authorities (and possibly state regulatory commissions) are willing to grant an unconditional certificate of public convenience and necessity based on these estimates. The preliminary approval stage is necessary, therefore, to recognize this unwillingness to spend large sums of money without some level of assurance that the project would be approved.

In the preliminary approval stage, a utility would not be locked into the preliminary cost estimates if any changes to the cost estimates were justified. Furthermore, the preliminary approval sets an abandonment recovery percentage where applicable. Under this percentage, the utility would be guaranteed recovery of a specified percentage of its design and cost estimation outlays in the event the project was cancelled.* This creates an incentive for the utility to spend considerable effort in making good estimates prior to final approval.

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* Because all outlays are tax deductible if the project is abandoned, a recovery fraction of x will result in an after-tax loss of approximately (1-x)/2 for a utility with a 50 percent marginal tax rate.

Exhibit 5.4

IMPLEMENTATION STEPS FOR A CONSTRUCTION COST CONTROL INCENTIVE PROGRAM

Step	Required from Utility	Required from FERC
1. Utility files request for a conditional certificate of public convenience and necessity	• Preliminary engineering design and specification • Preliminary project cost estimated in constant dollars by time period and cost category • Preliminary proposed inflation indices by time period for all cost categories • Proposed values for IROR parameters	
2. FERC issues conditional certificate of public convenience and necessity		• Initial projected capital costs for IROR in constant dollars by time period and cost category • Initial inflation indices by time period for all cost categories • Abandonment recovery percentage • Proposed IROR parameters
3. Utility files request for an unconditional certificate of public convenience and necessity	• Final engineering design and specifications • Final capital cost estimates in constant dollars by time period and cost category • Proposed AFUDC rate • Final proposed inflation indices by time period for all cost categories, with explanation of basis for differences between preliminary and final proposed indices • Comments on FERC-proposed IROR parameters • Proposed deadline for project scope changes	
4. FERC issues unconditional certificate of public convenience and necessity[a]		• Final projected capital costs (X_{it}) in constant dollars by time period and cost category • Nominal AFUDC rate • Final inflation indices by time period for all cost categories • Scope change deadline • Final IROR parameters (k and r_m)

Exhibit 5.4 (continued)

IMPLEMENTATION STEPS FOR A CONSTRUCTION COST CONTROL INCENTIVE PROGRAM

Step	Required from Utility	Required from FERC
5. If utility accepts certificate, construction begins	• Regular reports to FERC on construction cost outlays by time period • Request for scope change, if necessary	• Review of construction cost outlays with respect to prudency test
6. Upon the completion of construction, FERC sets the incentive rate of return based on the project's CPR and makes any necessary rate base adjustment		• Value for actual capital costs A based on equation (2), reported in Step 5, and AFUDC rate set in Step 4[b] • Value for projected capital costs P based on equation (3), actual inflation index values by time period (P_{it}), the predicted constant dollar outlays (X_{it}), and AFUDC rate set in Step 4 • Value of CPR based on equation (1)[c] • Value for IROR based on equation (4) and parameters set in Step 4 • One-time rate base adjustment

[a] If FERC deems the project uncertifiable, abandonment proceedings can be initiated or the utility may choose to redo Step 1.

[b] Any outlays deemed "imprudent" should logically be excluded from the calculation of A since they (and their corresponding AFUDC) will be excluded from the rate base.

[c] The cost performance ratio is calculated using the same prespecified AFUDC rate on both the predicted outlays and the actual outlays. For rate base purposes, AFUDC rates based on the actual capital costs and the mix of financing should be employed.

In the final approval stage, the utility would either receive an unconditional certificate of public convenience and necessity and proceed with construction; be required to revise the data, estimates, and specifications on which the project is based before the certificate was issued; or, decide to cancel the project because FERC refuses to grant the certificate or the utility assesses that the project is undesirable under the IROR conditions spelled out by FERC. In the IROR stage, FERC would set the ratemaking treatment of the completed construction project by determining the project's incentive rate of return based on revised projected and actual construction costs and the necessary one-time rate base adjustment.

AUTOMATIC RATE ADJUSTMENT MECHANISM BASED ON CHANGES IN PRICES OF FACTOR INPUTS

Recognizing that some regulatory commissions or utilities may be reluctant to implement or participate in the recommended incentive program, we discuss, as an alternative possibility, an incentive program that is based on a mechanism for automatically adjusting rates according to changes in the prices of factor inputs. Although the program has some weaknesses, we believe it warrants consideration by FERC and state commissions for possible implementation.

In this incentive program, a utility and its regulators would develop rates based on costs and operating levels that have been projected for the initial period in which the rates would be in effect. For a specified number of subsequent time periods, the rates would be automatically adjusted according to externally observed changes in the utility's production input prices and holding the input mix of the utility unchanged. After the initial rating period, the prices for the utility's production would be determined by economic conditions and forces that are outside the utility's control.

In some respects, this automatic rate adjustment mechanism (ARAM) is similar to the rail rate adjustment program implemented by the Interstate Commerce Commission for the U.S. railway industry (see Appendix E for a review of this program). In addition, the ARAM is similar to incentive rate programs that have recently been discussed in utility industry trade journals.* With regard to their incentive effect, the central concept underlying these programs is to simulate, for an extended period of time, the conditions of a competitive market (or the conditions that apply under regulatory lag) in which an individual firm cannot influence the market prices of its products. As a result, a firm would be strongly encouraged to achieve least-cost production, thereby maximizing its profits against the externally determined prices for its products.**

Under our proposed formulation of this program, the benefits or costs associated with a change in a firm's productivity would primarily be transferred to ratepayers through a periodic recalibration of utility rates to utility costs. Prior to the recalibration, however, the utility would receive most of the benefits or costs of a productivity change. At the time of recalibration, the new initial rates would reflect any changes in production costs that the utility had achieved during the previous periods in

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* For example, see: Gale, William A. "Price Index Components for Utility Rate Adjustments," Public Utilities Fortnightly, April 15, 1982; Balumol, William J. "Productivity Incentive Clause and Rate Adjustment for Inflation," Public Utilities Fortnightly, July 22, 1982; and Electric Light and Power, "PUCs Seek to Displace Growing Rate Awards with More Efficient Company Management," July 1982, p. 8.

** The ARAM program described here is a rate adjustment mechanism based on input price changes. Thus, the ARAM program differs markedly from a rate adjustment program implemented in New Mexico which focused on rate adjustments tied to changes in a utility's total cost of service, including changes in both input prices and cost of capital. For a discussion of the New Mexico program, see Appendix I.

which rates were adjusted automatically. In addition, the mechanism might be structured to transfer to consumers the benefits of an assumed minimum rate of productivity advance during the period of automatic rate adjustment. That is, a utility's production costs could be assumed to decline at some percentage after adjusting for changing input prices.

In the following section, we explain the workings of this program in greater detail. In the last section of this chapter, we evaluate the ARAM program and discuss certain weaknesses concerning its design which, if improved, would substantially enhance its usefulness as an incentive device.

Program Description

Although the program may be conceived as broadly applicable to many firms, its actual development and application would require that the operating characteristics of each specific firm participating in the program be considered. Therefore, our discussion of the ARAM program focuses on the design and implementation of an ARAM for a single firm.

An ARAM program could be implemented by FERC to apply to wholesale rates or by individual state commissions to apply to retail rates. The rate adjustment mechanism would operate as though the utility's mix of factor inputs and the technological relationship between inputs, as an aggregate, and output remain constant over time. However, by (1) altering the mix of inputs, or (2) altering the relationship between inputs and output, or (3) obtaining a lower rate of change for the input prices than the rate of change observed in the external indexes, the utility may obtain lower production costs over time than implied by the input price adjustments to the utility's rates. In this way, the utility may increase its earnings during the period in which its rates are adjusted to reflect externally observed changes in the prices of its production inputs.

An ARAM program involves three components: the formulation of a profile of a firm's input mix and cost structure at the program's inception, the development of price indexes or other means for tracking the change over time in the prices of the firm's inputs, and a comprehensive procedure for adjusting a firm's rates based on changes in its input prices.

Input Mix, Cost Structure Profile, and Internal Price Indexes

As the first step in implementing an ARAM program, a utility will file a rate case based on a future test year. The beginning of this future test year will coincide with the beginning of the first rating period in which the new rate program will be in effect. A rating period should be no longer than six months and could be as brief as three months.

In filing for the future test year, the utility and its regulators must project the firm's operating levels (i.e., energy requirements and demand), and the associated factor input requirements and their related costs for the entire year. The prices of the four groups of factor inputs--fuel, labor, other materials and supplies, and purchased power--may be expected to change during the future test year and the subsequent years in which the ARAM program will be in effect. Changes in these prices can be monitored externally to the firm.* Therefore, the utility and its regulators should project the expected test-year costs of these factor inputs on the basis of test-year quantities and prices projected to the middle of the first rating period.** For example, the utility's

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* Prices of capital-related inputs may also be expected to change over time. However, for several reasons that we discuss in detail later in this section, rate adjustments based on changes in the prices of capital-related inputs cannot currently be included in an ARAM program.

** Establishing input costs on the basis of prices projected for the first rating period is necessary because rate adjustments for the second rating period during the test year will be based on input price changes in the first rating period. A similar procedure will apply for future rating periods.

estimated gross annual fuel budget should be based on the quantities of the specific fuels the utility projects it will use during the future test year and prices by fuel type as projected for the first rating period.

After the utility and its regulators set the test-year costs of these four inputs, the regulatory commission will set the utility's test-year revenue requirement, which will be based on these input costs as well as other costs (including the return of and return on capital) that are not covered under the ARAM program. The regulators will then set rates designed to recover this revenue requirement. In developing these rates for different customer classes, the utility must separate the rates for each class into components that are based on the utility's variable operating costs (i.e., costs that vary with the level of production) and fixed costs (i.e., costs that do not vary with the level of production). Within the variable and fixed cost components of each rate, the utility must identify the contribution from each group of factor inputs and the specific inputs within each group whose prices vary over time. The contribution of each group and each specific factor input can be considered as internal price indexes. For example, assume that 50 percent of the kWh charge in a rate for an initial rating period represents fuel costs, of which 60 percent is accounted for by a specific fuel type. The internal gross fuel price index for this rate is 0.5, while the internal specific fuel type price index for the rate is 0.6. Thus, if the price of the specific fuel increases by 20 percent, the internal specific fuel price index will increase to 0.72 (i.e., 0.6 x 1.2) and the gross internal fuel price index will rise to 0.56.* Similar internal price indexes for each rate would be developed for each factor input whose price is reflected in the rate.

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* $[(0.6 \times 1.2) + (1 - 0.6)] \times (0.5) = 0.56$.

The utility and its regulators will presumably set the level of the fixed cost component of each rate on the basis of projected levels of electricity demand and consumption that are necessary to recover the utility's fixed costs (including return of and return on capital) during the future test year. For the variable cost component, it is presumed that rates will be set at a level that will recover, for each kWh of consumption, the cost of providing the energy on the basis of projected operating requirements and input prices during the future test period. Together, these components become the initial set of rates to which subsequent adjustments will be made on the basis of changes in the prices of the factor inputs with varying prices: labor, fuel, materials and supplies, and purchased power.

External Input
Price Indexes

In addition to developing the initial rates, identifying their cost components, and setting internal price indexes, the regulatory body must define external price indexes to use in adjusting the internal price indexes of the utility's inputs. External indexes must objectively track the prices paid for specific types of fuel, labor, materials and supplies, and purchased power in the utility's internal factor input index. For example, the New York Harbor price for residual fuel oil might be used for tracking this fuel's price for a New York utility. Coal might be followed as an average of spot prices for the coal districts supplying the utilities in a region.

Similar external input price indexes must be formulated for each of the other inputs for which prices will be adjusted. Labor prices can be tracked against a regional labor cost index maintained by the U.S. Department of Commerce or a state index, if available. Finding an external index for material and supplies is problematic because the composition of this input varies over time. An imprecise, but perhaps acceptable, index is the producer price index for intermediate goods reported monthly by the U.S. Department of Commerce. Alternatively, it may be possible to measure the monthly or quarterly changes in prices for materials and supplies for a sample of utilities throughout the nation or within a region. Indexing purchased power presents similar problems because of the varying composition of transactions and pricing terms over time. A possible method for indexing purchased power would be to sample the average price per kWh paid by a group of utilities for purchased power on a monthly or quarterly basis.

Rate Adjustment Procedure

As the price for a specific input changes during a rating period, the regulatory body will adjust the components of that input's internal price index according to the percentage change in its externally observed prices. For example, if during one rating period, the price of coal increases by 1.5 percent, then the coal component of the utility's fuel price index would be increased by 1.5 percent. The utility's rates for the next rating period would then be adjusted to reflect the percentage change in the index components of the utility's rates. These changes in rates would apply to both the variable cost and fixed cost components of rates. This rate adjustment procedure would be applied during each rating period for a maximum specified length of time, for example, three to five years.

As an example of how the rate adjustment procedure would work, consider how two rates (Rate A and Rate B) that only have kWh charges would be affected by a price increase in coal (as measured by the external price index for coal).* Rate A has an internal gross fuel price index of 0.60 and an internal coal price index of 0.45. That is, 60 percent of Rate A's kWh charge reflects the recovery of fuel-related expenses, of which 45 percent are coal-related expenses. Rate B has an internal gross fuel price index of 0.50 and an internal coal price index of 0.375 (see table on following page). These indexes are set for the initial rating period under the ARAM program.

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* For simplicity, we assume that only one type of coal is used in the utility's production process.

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* For simplicity, we assume that only one type of coal is used in the utility's production process.

RATE ADJUSTMENT: INCREASE IN PRICE OF COAL

Rate	Internal Price Index in Rating Period 1		External Price Index of Coal		Rate Adjustment Factor
	Fuel	Coal	Rating Period 1	Rating Period 2	
A	0.600	0.450	1.000	1.200	1.0540
B	0.500	0.375	1.000	1.200	1.0375

As shown in the table, the 20 percent increase in the price of coal would be reflected in a 5.4 percent increase in Rate A for the second rating period and a 3.75 percent increase in Rate B for the same period. Thus, if Rate A's kWh charge in the initial rating period were 60 mills/kWh, the charge for the second rating period would be 63.24 mills/kWh. Similar rate adjustments would be made to reflect price changes in other production inputs.

At the end of the automatic adjustment period (e.g., after three years), the utility's rates would be recalibrated to its production costs on the basis of a new future test year proceeding and the automatic rate adjustment process would begin anew. From this time forward, any cost reduction benefits that the utility had achieved during the previous three-year period would now be passed on to ratepayers.

Additional Rate Adjustments

In addition to the rate adjustments based on changes in input prices, the fixed cost component of the utility's rates may also be adjusted during the three- to five-year period to reflect changes in customer demand and consumption (from the levels projected by the utility for the future test year) that would cause the utility to over- or under-collect its fixed charges. These changes might be made annually. For example, on the basis of current rates, if the expected level of demand for the upcoming year would cause the utility to collect appreciably more than its fixed costs, then the fixed cost component of the rates would be adjusted downward for the next year.

As we noted above, cost reductions (benefits) achieved by the utility during an automatic adjustment period (e.g., three years) would typically be passed on to consumers when the utility's production costs are recalibrated at the end of the period.* However, it would be possible to transfer either the presumed or measured benefits to ratepayers before recalibrating the utility's rates to its production costs. One method for accomplishing this would be to assume a rate of reduction in production costs per unit of output (e.g., one percent per year). At the same time that rates were being adjusted in response to changes in input prices, the unadjusted base rates to which the automatic adjustments are made would be declining at an annual rate of one percent. However, regulators must be careful not to try to transfer more than a small part of the potential benefits from prospective productivity improvements to ratepayers through this type of adjustment. If the utility is not allowed to retain most of the potential benefits from productivity changes in the automatic adjustment period, regulators will find themselves having to make frequent non-systematic rate adjustments because the utility will show deficient earnings (see discussion below).

A more precise method of transferring benefits (or for that matter, increased costs) to ratepayers during the three-year period would be to compare, on a quarterly basis, the utility's aggregate costs for the inputs on which rates are adjusted, with the revenues assigned to those inputs as indicated by their adjusted rates. If the actual costs deviated significantly from the projected costs, as indicated by the index, the firm's rates might be partially adjusted to reduce the deviation. For example, in any rating period when the utility's costs for the indexed inputs were 10 percent above or below the corresponding revenues, the utility would split the excess (above or below 10 percent) with ratepayers on a 50/50 (or other) basis in the next rating period. Alternatively, the firm's actual earned return might be monitored on a quarterly or annual basis. If the actual return

* This discussion also applies to cost increases incurred by the utility.

deviated by more than, say, three percentage points from the target allowed return, then the firm's rates might be adjusted to transfer 50 percent of the excess or deficiency in earned return (above or below the three percentage point difference) to ratepayers. That is, the firm's rates would be adjusted to bring the firm halfway back to the target return plus or minus three percentage points.

No other systematic adjustment to rates would be expected during this period. However, in certain defined circumstances, regulators might authorize a special adjustment to rates or require a basic recalibration of the rates to utility costs. These circumstances might include the following:

- The utility adds a new large unit, substantially altering its fixed charges and mix of factor inputs; in this case, the input mix and fixed cost allowance for the utility's rates would be adjusted. However, the internal index levels for specific inputs would not change.

- Capital market conditions change substantially such that the allowed return embodied in the utility's fixed cost component of its rates is no longer reasonable (too high or too low); in this case, the fixed cost component of rates might be adjusted to reflect a new allowed return on equity.

- Rolling over debt at substantially different interest rates causes the firm's fixed costs to change; again, the fixed cost component of rates might be adjusted to reflect the revised cost-of-capital.

- Unforeseeable circumstances that are beyond management's control cause the utility to lose a major generating unit (e.g., the federal government requires a lengthy shutdown of certain types of nuclear units); in this case, the initial internal price indexes for specific fuel types in the utility's gross internal fuel price index would be shifted to reflect the revised fuel consumption mix. This change would be based only on changes in the fuel consumption mix and not on changes in the prices of the specific fuel inputs.

Program Evaluation

The ARAM-based incentive program has several important strengths relative to our criteria for designing and evaluating an incentive program. First, with the three- to five-year period between index/rate recalibrations, firms will have substantially more opportunity than is available in the current regulatory environment to undertake, and reap the profits from, cost-reducing improvements in their operations. As a result, the program should encourage firms to aggressively seek reductions in their production costs by altering their input mix, improving productivity, or obtaining lower prices for their factor inputs. Second, the program provides an explicit mechanism for transferring the economic results from changes in management performance to ratepayers. Initially, the firm will retain all of the economic consequences of its performance; however, within a few years, the economic results will be transferred to ratepayers through a recalibration of the rate adjustment index. Third, once established, this incentive program would be relatively easy to administer and could result in a substantial lengthening of the period between a firm's formal rate cases. As a result, the administrative costs of the regulatory process for both firms and regulators should be reduced. Fourth, with adequate care given to developing the bases for tracking the prices of inputs consumed in the utility's production process, this program should be equitable in terms of the manner in which it rewards or penalizes firms for their performance. Moreover, for cases where factors beyond management's control began to affect the utility's earnings performance significantly, the program could contain a provision for the interim revision of rates and a recalibration of the rate adjustment index. Alternatively, as discussed earlier, a formula could be devised for dampening wide deviations in actual earnings return from allowed return.

At the same time, the ARAM program has weaknesses relative to the preferred program described in Chapter 4. The major weakness is the current lack of an acceptable method for indexing a firm's capital-related costs. As we have outlined the program, these costs would not be included in the rate adjustment index. Accordingly, the level of rates designed to recover capital-related costs would not be determined by the automatic rate adjustment mechanism; rather, capital cost recovery would remain under the influence of the firm. Specifically, during the period between scheduled index recalibrations, firms will be encouraged to substitute capital for inputs covered by the index as long as they are able to receive rate increases in conjunction with additions to the rate base.

The issue of indexing capital-related components of a rate adjustment mechanism has generally been ignored by most analysts.* Moreover, problems inherent in developing capital-related price indexes and rate-component adjustment mechanisms in the electric utility industry have been clearly demonstrated.** In general, these problems focus on identifying appropriate external indexes and procedures that could be used to reflect the changes over time in a

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* If this issue has not been ignored, analysts have implied that the issue can be resolved rather easily (for example, see Baumol, op. cit., and Sinden, op. cit.). Another analysis (Lindhard, P.B. and Sinden, F.W. "Productivity Incentives Under Rate Regulation." Bell Laboratories Economic Discussion Paper #236, January 1982) implies that external price indices can be easily obtained for both capital and labor inputs. An analysis by Gale, op. cit., describes the development of a capital input index applied to the Bell Telephone System. Gale concluded that additions to the capital stock of any one of the Bell System's relatively homogeneous firms will not have any significant impact on the System's capital cost index. However, problems arise in attempting to apply this situation to the electric utility industry: even if a capital cost index could be developed for the entire industry, it could not sufficiently describe the changes in capital costs for an individual utility. This is because the capital costs for an individual utility typically are characterized by relatively large, discrete increases (as the firm adds new capacity), which would be poorly approximated by an industry-wide index.

** Frederick, J.S. The Regulation of Electric Utilities Under Conditions of Inflation: A Proposal and Evaluation of an Automatic Inflation Adjustment Mechanism. Unpublished Ph.D. dissertation, University of Wisconsin at Madison, 1976, pp. 121-173.

utility's rate base, capital structure, and cost of capital. For example, what external index or procedure could be used to determine what the value of a firm's rate base should be in rating periods outside the future test year, but within the three- to five-year rate adjustment period?

Additional research is required to resolve this problem. Specifically, generic procedures (i.e., procedures that are applicable to a wide range of electric utilities and cannot be influenced by an individual utility) and external price indexes that could be applied on a utility-specific basis must be developed for determining:

- Adjustments to the rate base, excluding depreciation, occurring after the future test year but before the end of the rate adjustment period
- Rate adjustments to reflect depreciation of the rate base over the rate adjustment period
- Capital structure for the initial rating period only
- Rate of return on equity and changes in it over time
- Embedded cost of debt and preferred stock and the changes in this capital cost component created by new debt issues and retirements of these fixed-coupon securities
- Income taxes on the firm's earnings and changes in taxes over time between the end of the rate adjustment period and the end of the future test year
- Miscellaneous expenses that will change with changes in the undepreciated rate base over the rate adjustment period (e.g., selected insurance and property tax expenses).

The FERC may initiate a formal rulemaking proceeding to address the generic rate of return issue.* However, a great deal of research and analysis will be required to resolve the remaining capital cost and rate base issues.

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* Federal Energy Regulatory Commission. "Generic Determination of Rate of Return on Common Equity for Electric Utilities: Notice of Proposed Rulemaking, Docket No. RM 80-36-000." Federal Register, Vol. 47, No. 169, August 31, 1982, pp. 38332-38346.

A second weakness of the ARAM program relative to the program described in Chapter 4 is that it will likely increase a firm's cost of capital. Because the program discussed in Chapter 4 affects the firm through adjustments to management compensation, it should have no adverse effect on a utility's cost of capital. However, the ARAM program will directly affect a firm's revenue level and, other things held equal, its earnings. If investors and lenders perceive greater risk with regard to the firm's earnings and interest coverage, then both debt and equity costs may be increased.

Third, because the ARAM program, through its impact on earnings, has a more direct effect on a utility's stockholders than on its management, it may not be as effective as our recommended program in encouraging firms to minimize their costs. The focus on earnings rather than rates (as in our recommended program) is necessary because under the ARAM program, a utility's rates are determined by factors outside the control of management. Thus, firms covered by the ARAM program should also implement programs that tie management compensation to earnings performance.

Fourth, there may be an opportunity or incentive for firms to "game" the system by delaying the implementation of cost-reducing improvements until just after rate levels are recalibrated to the input price index. In this way, a firm would retain the benefits of a cost-reducing action for the full period between index/rate recalibrations. Although it may seem somewhat contrived, one possible way to avoid this problem would be to have the length of time between recalibrations be unknown to the firm and specified on a random basis. As a result, a firm will not know the length of time it will have to delay a cost-reducing improvement (and its associated increase in profits) in waiting for the recalibrations. However, this random recalibration introduces additional uncertainty in the utility's decision-making process and, in some circumstances, may result in the utility's delaying a cost-saving investment even longer than it might (because of the incentives to game) under a fixed rate adjustment period. A further analysis of the game theoretic implications of this situation is required before we could conclusively support the use of a random recalibration approach for reducing the opportunity to game the system.

APPENDIX A

REVIEW OF SELECTED STATE-LEVEL PROGRAMS

In recent years, a number of state regulatory commissions have adopted programs to improve the productive efficiency of electric utilities. The most common type of program adopted is one that ties the amount of selected operating expenses (e.g., fuel costs) that a utility is allowed to recover from ratepayers to the utility's performance at specific operating levels (e.g., performance as measured by the availability of baseload generating units).

In general, these state-level programs establish a system of rewards and penalties for short-term operating performance relative to a set of pre-selected performance standards. For example, the amount of fuel and purchased power expenses that utilities in Florida and California are allowed to recover from ratepayers through rate adjustment mechanisms is determined in large part by using the availabilities and heat rates of baseload generating units as the performance standards. Similarly, the amount of non-production-related operating and maintenance (O&M) expenses that utilities in Michigan are allowed to recover through base rates is tied to a national cost index.

At least three state regulatory commissions--New York, New Jersey, and Illinois--have adopted programs that focus on longer-term performance. In this case, performance is measured by the extent to which a utility is able to keep its construction costs for large generating units within forecasted estimates. These longer-term programs are designed to create incentives for accuracy in estimating project costs and efficiency in completing major construction projects. This is accomplished by tying the amount of project costs that will be included in the utilities' rate bases to deviations in the completed project's cost from the originally estimated project costs.

Five state-level efficiency improvement programs that are in effect or are being developed in Michigan, Florida, and Utah were reviewed with two major objectives in mind. First, we wanted to identify similarities and differences in the objectives and areas of focus of the programs. Second, we wanted to determine whether the programs meet the criteria described in Chapters 2 and 3 in terms of defining performance, measuring performance, and structuring incentive mechanisms. The five programs reviewed were:

- Power plant performance programs in Florida and Michigan,
- A fuel and purchased power incentive program in Michigan,
- A rate adjustment program in Michigan that links the level of non-production-related O&M expenses recovered in base rates to the Consumer Price Index, and
- A utility efficiency program in Utah.*

In reviewing each state program, we asked the following questions:

1. At which area(s) of utility operations is the program targeted?
2. How is performance in the target area(s) measured?
3. Does the program establish performance standards, and, if so, how?
4. Are rewards and penalties imposed for performance that deviates from the established standards?

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* Although they are not described in this appendix, we also reviewed power plant performance programs in Arkansas, North Carolina, California, and Connecticut, and construction cost incentive programs in New York, New Jersey, and Illinois. Selected elements of the programs in New York, New Jersey, and Illinois are incorporated in the construction cost control incentive mechanism that we recommend to FERC for further consideration. This mechanism is described in Chapter 5.

5. What are the program's administrative requirements?

6. Has the program's effectiveness been measured?

7. Is the program potentially suitable for adoption by the FERC?

On the basis of our review, we concluded that none of the performance improvement programs in Florida, Michigan, and Utah is suitable for implementation by FERC. This conclusion was drawn because all of the programs have a short-run, sub-corporate level of focus. The primary goal of any regulation incentive program should be to encourage utilities to provide reliable electric service at the least possible cost. However, because it tends to assume automatically that overall corporate efficiency is maximized if one or more sub-corporate level performance standards are met, a short-run, sub-corporate focus fails to address two important short-run allocative efficiency issues. The first issue deals with potentially sub-optimal (i.e., inefficient) trade-offs between factor inputs in the target area of operations. For example, a generating unit availability program may encourage a utility to substitute high-quality, high cost coal for lower-cost, lower-quality coal in a non-cost-effective way, simply to improve generating unit availability. The second issue deals with potentially sub-optimal trade-offs between the factor inputs used in target and non-target areas of operations. For example, an availability program may encourage a sub-optimal distribution of maintenance expenses between the utility's generation and distribution functions, resulting in higher generating unit availability, but lower-quality service and higher average electricity costs to customers served from the secondary distribution system.

An efficiency improvement program with a short-run, sub-corporate level focus may also not be allocatively neutral in the long-run. For example, a generating unit availability program may encourage a utility to maintain an excessive level of spare parts for generating units; buy only the highest quality, highest cost replacement parts; and replace parts more often than necessary. These actions are taken because the program has created an incentive to select types and sizes of units on the basis of minimizing the penalties or maximizing the rewards associated with availability targets, instead of minimizing the present value of long-run electricity costs at an acceptable level of reliability.

In addition to the limitations created by their short-run, sub-corporate level focus, these state programs would probably be administratively infeasible at the federal level. For example, a generating unit availability program would require that FERC develop and apply performance standards to over 150 utilities, as well as determine and distribute the rewards and penalties for each utility during each performance measurement period. More important, by designing and implementing programs with a short-term, sub-corporate level focus, FERC would be assuming the role of management by forcing the utilities to make specific operating and investment decisions that may not be in the best long-run interests of their ratepayers. As stated above, the primary goal of an incentive regulation program to promote productive efficiency should be the delivery of electricity to customers at an acceptable level of reliability and at the lowest possible cost. How a utility's management chooses to respond to incentives to meet this goal should be immaterial to regulators. Therefore, programs with a broader, longer-term focus that minimize the potential for direct interference by regulators in specific operating and investment decisions seem more reasonable for implementation by FERC.

FLORIDA: GENERATING PERFORMANCE INCENTIVE FACTOR

In 1980, the Florida Public Service Commission (PSC) implemented an incentive mechanism designed to promote the efficient operation of the generating units operated by Florida Power & Light Company, Florida Power Corporation, Tampa Electric Company, and Gulf Power Company. This mechanism, known as the Generating Performance Incentive Factor (GPIF), operates in conjunction with the PSC's six-month projected levelized Fuel and Purchased Power Cost Recovery Clause (FPPC). The GPIF provides monetary rewards or penalties to a utility based on differences between its generating units' actual equivalent availabilities and average net operating heat rates during a six-month period, and target availabilities and heat rates for that period.

Each of the four utilities submits equivalent availability and heat rate targets to the PSC for each of its generating units that is covered by the GPIF program. These targets are primarily based on data reflecting each unit's operating history, although other factors are also considered, such as abnormal operating conditions and known improvements in unit equipment. The PSC then sets prospective availability and heat rate targets each six months, in conjunction with setting the FPPC level. At the conclusion of each six-month period, the actual unit availabilities and heat rates of each utility's generating units are compared with the targets. On the basis of this comparison, the utility may receive a monetary reward or penalty.

Although the GPIF program appears to be working reasonably well in Florida, its administrative complexities and short-term, sub-corporate focus severely limit its potential applicability for FERC. For example, the biannual requirements to conduct hearings, set targets, and evaluate the performance of the utilities it regulates would necessitate that FERC dedicate substantial staff to carry out a GPIF-type program. In addition, generic criteria for setting reward or penalty levels would probably be required.

Moreover, no empirical evidence exists to support the notion that the GPIF program has lowered both the short- and long-run costs of electricity to consumers in Florida. For example, the PSC has not determined whether the penalties levied on a utility increase the utility's cost of capital, thereby potentially increasing rates in both the short- and long-run.

Another major problem with GPIF-type programs is that subjective adjustments must be made regarding targets, rewards, and penalties in order to reflect operating conditions that may be outside the control of management. For example, the Florida PSC can make adjustments to a unit's actual average heat rate and equivalent availabilities (including omitting the unit from the GPIF calculation) to reflect factors such as major design changes or unusual operating conditions.* In addition, the PSC

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* Roach, E. M., Jr. and Tarletz, D.B. The Application of Generating Unit Performance Standards in Ratemaking Proceedings--An Update. Paper presented at the Edison Electric Institute Legal Committee Meeting, Spring 1982, pp. 11-12.

may determine through an investigation whether unusual operating conditions are actually outside the control of management. The PSC recently made such a determination on a 167-day outage in 1980 of a nuclear generating unit owned by Florida Power Corporation (FPC). The PSC ruled that the outage was extended seven days longer than necessary because FPC did not have a spare decay heat pump on hand and refused to allow FPC to pass the $3.5 million outage cost (the estimated extra fuel costs incurred by the extension of the outage)* through to ratepayers.

Below, we describe various aspects of the Florida GPIF program in more detail.

Target Performance Areas

The GPIF program focuses on only two aspects of generating unit operations: equivalent availability and heat rate. These performance areas were chosen on three grounds. First, it was assumed that utility management can directly influence generating unit performance as measured by equivalent availability and heat rate. Second, historical data on these performance measures for the units covered by the GPIF program are readily available. Third, these two measures were already used as inputs in the production costing simulation models used by the PSC in projecting each utility's fuel requirements and expenses in the FPPC hearings held every six months.

Every six months, the PSC sets performance standard targets for the equivalent availability and average heat rate of each major generating unit operated by the four utilities in the GPIF program. These targets reflect how each unit is expected to perform during the same six-month period encompassed by the projected FPPC.

The maximum and minimum equivalent availabilities that can reasonably be achieved by a generating unit form the range within which the PSC selects the equivalent availability

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* Electric Light & Power. "The $3.5 Million Heat Pump," Vol. 60, No. 9, September 1982, p. 700.

target for that unit. These maximum and minimum unit availabilities are estimated on the basis of the unit's historical operating performance and potential changes in its unscheduled outage rates (for both total and partial outages). An equivalent availability target for an upcoming six-month period is then set within this range, taking into account the unit's historical operating performance, expected scheduled and unscheduled outages over the next six months, and adjustments to reflect factors such as abnormal operating conditions or equipment modifications. For example, a unit with historically low outage rates might have its target equivalent availability rate set at the upper end (i.e., maximum) of the range.

In setting the heat rate range for a generating unit covered by the GPIF program, historical data on the unit's average monthly heat rate and net output are collected. The data for each month are then adjusted to reflect changes in certain factors. These factor changes (e.g., equipment modifications) must have occurred since the data were collected. In addition, it must be assumed that the changes would have affected the unit's average heat rate and output for that month. Regression analyses are performed on the data and a 90 percent confidence interval is estimated around the mean (average) of the data for each unit. The lower and upper bounds of this confidence interval (or range) represent the minimum and maximum average heat rate, respectively, that the unit can be expected to achieve. To set a unit's target heat rate for an upcoming six-month period, the net output of the unit during each month of that period is estimated. Coefficients derived in the regression analyses are then applied to the estimates of monthly net output to estimate the unit's average heat rate in each month. The weighted average of the six-month average heat rates is then set as the unit's target heat rate for the upcoming six-month period. A band of ± 75 Btu/kWh is set around the target as a neutral zone to compensate for reasonable deviations from the target that may be beyond control of the utility's management.

Rewards and Penalties

A utility covered by the GPIF program may receive a financial reward or penalty on the basis of its generating unit's actual performance during a six-month period relative to the target equivalent availabilities and average heat rates for those units. The maximum reward or penalty that can be imposed under the program each six months is equivalent to an incremental or decremental return of 25 basis points on the utility's jurisdictional common equity during the six-month period.*

The determination of a utility's reward or penalty involves a series of complicated steps. First, the equivalent availability points and the average heat rate points are calculated for each unit. At the end of each six-month period, each generating unit's performance is compared to its equivalent availability and heat rate targets. Deviations in a unit's actual performance measures relative to its target performance measures are estimated. These deviations are then adjusted through a series of arithmetic calculations specified by the PSC to estimate equivalent availability points and average heat rate points for each unit.** Positive or negative point values are assigned for performance above or below each target, respectively.

In the second step, the equivalent availability (average heat rate) point value of each unit is multiplied by the potential percentage reduction in system-wide fuel costs that would have resulted if the unit had operated at its maximum equivalent availability (minimum heat rate) over the six-month period. These percentages are derived from computer simulations of the utility's operations. The products of these multiplications are summed across all

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* Note that the determination of rewards and penalties creates a direct link between a utility's capital structure and the performance of its generating units. Thus, a utility that has units with high availabilities and low heat rates has an incentive to bias its capital structure toward equity to increase the potential rewards under the GPIF program.

** No adjustment is made to a unit's heat rate deviation if the unit's actual heat rate was within ± 75 Btu/kWh of the target heat rate.

generating units to yield the utility's generating performance incentive points for the period.

The final step in the reward/penalty determination is to multiply the utility's generating performance incentive points by the maximum allowable reward/penalty, as determined by the product of 25 basis points times the utility's jurisdictional common equity rate base. The maximum reward can only be achieved if all generating units operate at their maximum potential equivalent availabilities and minimum potential heat rates, as defined by the ranges for these performance measures. Similarly, the maximum GPIF penalty can be imposed only if all generating units operate at their maximum potential equivalent availabilities and maximum potential heat rates, as defined by the ranges for these performance measures. Because neither of these extremes is likely to occur, no utility is likely to receive a maximum reward or penalty. The level of rewards and penalties imposed by the PSC under the GPIF program varies. For example, on January 8, 1982, the PSC:

- Granted rewards of $448,495 to Tampa Electric Company and $356,259 to Florida Power & Light Corporation, and

- Imposed penalties of $229,540 on Florida Power Corporation and $36,410 on Gulf Power Company.*

Administrative Requirements

The GPIF Program imposes a need for additional personnel at both the PSC and the utilities to complete the numerous data collections, analyses, and calculations required by the program. For example, PSC personnel are needed to monitor and audit each utility's fuel procurement procedure, collect data and perform the computer simulations necessary to develop performance targets and calculate rewards and penalties, and participate in the GPIF proceedings. No detailed analyses of the administrative costs of the GPIF program have yet been performed. However, on the basis of information we have concerning the number of PSC and utility personnel involved in the GPIF program and the program's major data and analytic requirements, a GPIF-type program would appear to be administratively infeasible for FERC, which regulates more than 150 utilities.

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* Roach and Tarletz, op. cit., p. 12

MICHIGAN: FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE

In 1976, the Michigan Public Service Commission (PSC) established the Fuel and Purchased Power Adjustment Clause (FPPC). Under the FPPC, the PSC establishes a base amount of total fuel and purchased power costs that a utility is expected to incur in a future test year. A utility's FPPC is established as part of a general rate case and remains in effect until a new base is established in a subsequent rate case. The annual base amount is disaggregated into estimated fuel costs and purchased power expenses by month. The fuel cost portion of this clause is automatically applied every month, while the purchased power portion is applied subsequent to monthly public hearings.

In general, if the company's actual fuel and purchased power costs exceed the base amount, the company can only collect 90 percent of the excess. Likewise, if its actual costs are below the base amount, the company is required to flow 90 percent of the decrease through to its customers and is allowed to retain the remaining 10 percent.

The FPPC provides incentives for utility managers to minimize their short-run fuel and purcahsed power costs by bargaining hard in making fuel procurements and by operating generating units efficiently. Moreover, the manner in which fuel and purchased power are treated under the FPPC gives companies an incentive to make efficient tradeoffs between generating power with their own resources and purchasing it from other sources. For example, if a company can purchase energy at less cost than it can generate energy from its own units, it will be financially better off under the FPPC by making the purchase. A secondary positive effect of the FPPC is that it may encourage utilities to improve the accuracy of their short-term forecasts of test year sales and fuel prices because the base FPPC costs are determined from these quantities.

There are, however, two potential problems associated with the FPPC. First, the clause is based on forecast sale levels that are subject to considerable fluctuations which are beyond management's control. To the extent that more fuel is needed to meet higher-than-anticipated demands, fuel costs will be pushed above the FPPC base, and the company may be unduly penalized. Conversely, the company may be rewarded if its sales are less than those forecast; in this case, the decrease in fuel costs and the associated reward under the FPPC would not be a result of management actions. A second potential problem is that the base fuel costs included in the FPPC are estimated from future test-year projections. Actual fuel prices during the test year may deviate from these projections. To the extent that these deviations are beyond management's control, a utility may receive rewards or penalties resulting from price movements over which it has little control.

The Michigan FPPC approach appears to have limited potential for the FERC. In particular, the requirement to conduct monthly hearings to evaluate purchased power costs would create a heavy administrative burden on FERC. Moreover, it would require that FERC establish staff expertise to carry out audits and investigations of the operating practices of each utility involved.

Target Performance Areas

By focusing directly on the fuel costs and purchased power expenses incurred by a company, the FPPC creates incentives for efficient purchasing and operating practices, especially with respect to committing and dispatching generating units efficiently and combining own-system generation and power purchases in an optimal manner. During a general rate case, a utility is required to project its kW and kWh sales, purchased power requirements, and fuel costs and purchased power expenses for a future test year. Production simulation models are used to make these projections. The analyses, data inputs, and assumptions are reviewed and evaluated by the PSC and intervenors during the rate case.

Each month a utility is required to submit information to the PSC concerning its fuel and purchased power expenses incurred during the preceding month. The PSC accepts the actual fuel expense data without review. However, the purchased power cost data are reviewed in a formal public hearing. On the basis of this review, the PSC may adjust the utility's actual purchased power costs to determine the amount of these costs that the company will be allowed to flow through under the FPPC. For example, if a company's monthly purchased power costs exceeded its base for the month, the company would typically be penalized 10 percent of the excess costs. However, if the excess was due to factors beyond management's control (e.g., a higher demand than forecasted), the PSC might waive the penalty and allow the full pass-through of these excess costs to ratepayers.

Rewards and Penalties

If the company holds either its fuel or purchased power costs, or both, below the base amount for the preceding month, it is allowed to retain 10 percent of the decrease. Conversely, it must absorb 10 percent of any costs in excess of the base amounts unless the PSC makes an offsetting adjustment. To place these potential rewards and penalties in perspective, if Detroit Edison Company were to reduce its fuel costs by 10 percent below the FPPC base, the company's share of these savings (i.e., one percent) would increase its after-tax earnings by about two percent.

Administrative Requirements

The FPPC entails the administrative requirements typically associated with fuel and purchased power adjustment clauses: establishing base costs, measuring current costs, and providing for current adjustments to rates. In addition, the Michigan FPPC requires monthly hearings on purchased power costs to determine the extent to which these costs will be allowed. In this respect, the hearings could become burdensome if the company and the PSC have substantially different interpretations on the allowability of costs. Moreover, the PSC must possess, or otherwise have access to, specialized technical expertise on utility operations. However, the Michigan PSC has indicated that the administrative requirements created by the FPPC are not significantly greater than those associated with more general types of adjustment clauses. In addition, because the PSC conducted monthly hearings before implementing the FPPC, the PSC and its companies required very little, if any, additional manpower or informational resources to implement, administer, and monitor companies' actions pursuant to the FPPC.

For regulatory commissions that do not have fuel clauses, do not hold monthly fuel cost hearings, or do not have sufficient technical staff expertise, implementing a program similar to the Michigan FPPC will represent a potentially significant increase in their administrative workload.

MICHIGAN: OTHER O&M INDEXING SYSTEM

In 1979, the PSC implemented an automatic rate adjustment mechanism for Detroit Edison and Consumers Power, which covers these utilities' non-production-related operating and maintenance expenses (all O&M expenses other than fuel, purchased power, and production maintenance expenses). Changes in the companies' allowed revenue collections for these "other" O&M expenses are tied to the annual change in the national Consumers Price Index (CPI). Specifically, the PSC established a base level of other O&M expenses for each company based on the company's historical data. Each year, a company is allowed to collect its base amount, adjusted to reflect cumulative changes in the CPI. These expenses are recovered through the company's kWh charges. For example, if the CPI increased 22 percent in the first three years after a company's base level was established (i.e., the first two years the kWh rate adjustment was in effect), the company would be allowed to collect 1.22 times its base level expenses in the third year. The intent of the O&M indexing system is to introduce a form of competition to the utilities, i.e., management must compete with the CPI in managing the covered O&M expenses. A company whose covered O&M expenses exceed its CPI-adjusted base level may not be allowed by the PSC to pass the excess through to ratepayers.

The indexing system appears to provide a clear incentive to the utilities to minimize their expenses in the areas covered by the mechanism. Moreover, because the indexing system covers costs that affect a large portion of the utility's operations, essentially a company-wide program is required for the utility to respond fully to the cost control incentives created by the indexing mechanism.

However, there are several drawbacks to this mechanism. First, the CPI is not necessarily a good indicator of utility cost trends, regardless of whether the company is efficiently or inefficiently managed. In particular, the CPI contains many elements (e.g., clothing, food, and housing indicators) that may have little if any relationship to utilities' operating and maintenance costs.

Local cost trends may also differ from the national average measured by the CPI. Furthermore, the utilization of the CPI as an index institutionalizes inflationary pressure within the economy because utility rates are incorporated in the CPI.

Second, the CPI indexing approach does not account for underlying structural changes in a company's other O&M requirements. For example, system growth necessitating expanded transmission and distribution facilities or new cost-justified activities such as load management or conservation programs can increase other O&M costs at a rate greater than the rate of change embodied in the CPI.

Third, the CPI indexing system may create a bias toward capital intensiveness on the part of a utility. For example, in designing a substation, a company may be motivated to overdesign it or build in features that reduce its O&M costs below the optimal level.

Fourth, the mechanism, as implemented by Michigan, does not appear to subject the companies' other O&M expenses to regular scrutiny to determine their reasonableness or to achieve a reasonable matching of revenues with these costs.

Fifth (and closely related to the second drawback), if the company's other O&M costs increase more than the CPI (whether for reasons of inefficiency or factors beyond management control), the impact will be decreased earnings, which may increase the company's cost of capital. In this case, both the shareholders and the ratepayers are penalized.

Target Performance Areas

This indexing mechanism is intended to provide the utilities with an incentive to keep their increases in other O&M expenses below increases in the CPI. The index covers a large portion of a utility's total costs. For example, approximately 16 percent of Detroit Edison's total costs are other O&M expenses.

The performance measurement indexing mechanism begins by setting a base level of each company's other O&M expenses. The PSC established base levels for each company in 1978, reflecting its evaluation of ten years of other O&M costs.

On the basis of this evaluation, the PSC determined that the changes in the companies' other O&M expenses essentially followed the CPI. The measurement of performance is simply the rate of change in the companies' actual other O&M expenses for the period covered relative to changes in the CPI for the same period.

Adjustments are made annually to a company's rates to reflect changes in the CPI. Specifically, in December, each company files the proposed changes in its rates based on two factors: (1) the change in the CPI from September of the previous year through August of the current year, and (2) total kWh jurisdictional sales for the test year. The kWh rate adjustment is put into effect in February of the next year.

Rewards and Penalties

The rewards and penalties associated with the O&M indexing system mainly accrue to the companies. If a company can hold the increases in its other O&M expenses below the increases in the CPI, it is allowed to keep the cost savings, which in turn will increase its earnings. For example, if Detroit Edison were to outperform the CPI by one percent, the company could achieve an earnings per share increase of approximately two percent. On the other hand, if a company's other O&M costs rise faster than the CPI, the company must either bear the total cost of the revenue deficiency created by the under-recovery of other O&M expenses, or request during a formal rate case that the PSC allow its rates to increase to meet the revenue deficiency. However, the PSC may elect to deny the utility's request.

Administrative Requirements

The CPI indexing mechanism could be implemented by FERC or by other states with relative ease. A one-time intensive effort would be required to establish a base level of other O&M expenses for each company. From that point, the implementation would be relatively straightforward. Because of the five drawbacks listed above, however, the application of the CPI indexing method appears to have limited potential at the FERC level.

MICHIGAN: AVAILABILITY
INCENTIVE PROVISION

The Availability Incentive Program (AIP) was adopted by the Michigan PSC in 1977 to encourage Detroit Edison and Consumers Power Company to increase the system availability of their generating units. Under the AIP, the companies may earn an increase of up to 50 basis points or a decrease of as much as 25 basis points on their allowed return on equity. Specifically, the adjustment reward or penalty to a company's allowed rate of return on common equity depends on the overall availability of generating units in the company's system.

The AIP provides an incentive for company management to improve the availability of existing generating plants in the short-run and to incorporate availability targets into the company's construction planning process for the long-run. Discussions with PSC staff and representatives from Detroit Edison and Consumers Power indicate that an "availability consciousness" exists in the utilities as a result of the AIP. For example, in both companies, plant operating personnel are aware of the AIP and are fully indoctrinated into the reporting process.

A specific example of the impact of increased plant availability is Detroit Edison's Monroe power plant. Increased operating and maintenance training, reductions in unit startup time, and improved coal pulverizer performance has resulted in the Monroe plant's availability increasing from 69 percent in 1976 to approximately 85 percent today. (The U.S. utility industry's average availability for a generating plant in this size range is approximately 70 percent.) The company estimates that this improved efficiency saves customers $70 million per year in replacement energy costs. Detroit Edison has also incorporated availability targets into its construction planning process. For example, the company's Belle River coal units have been specifically designed with an equivalent availability of 85 percent.

The AIP includes two primary safeguards to prevent the companies from using their resources inefficiently to improve their availability. First, because the AIP focuses exclusively on one aspect of a utility's operations, it could provide a utility with disincentives to utilize its resources in the most efficient manner. However, the Michigan AIP is designed to minimize distortions in resource utilization. For example, a utility could idle its plants and purchase power to meet its load and still operate at 100 percent availability (i.e., the company would have generating plant(s) available, but not in operation). However, the PSC's Fuel and Purchased Power Adjustment Clause, which is discussed in a previous section, should counterbalance this possible adverse effect. Second, the AIP also provides utility management with an incentive to commit its resources for plant maintenance in an inefficient manner. That is, excessive maintenance expenditures could be used to improve plant availability to the point at which the marginal value to consumers of improvements in system availability is less than the marginal dollar cost of production maintenance expenditures. However, the PSC's prospective review of each utility's production maintenance expenses is designed to prevent the utility from incurring excessive levels of these expenses.

Even with these safeguards, the AIP has three potential drawbacks. First, the program might induce a utility to reduce its off-system sales, thereby reducing wear and tear on its generating units as a result of running units more than is required to serve own-load demands. In that off-system sales are generally treated as negatives to the utility's cost of service, reducing such sales could have a detrimental effect on the company's ratepayers. (However, there has been no indication that this potential problem has occurred under the AIP.) Second, the program may encourage utilities to take sub-optimal, long-term steps to improve their system availability by over-designing generating units that are scheduled for construction and by choosing to build certain types of units on the basis of their expected availabilities instead of their expected life-cycle costs. Third, a system availability performance measure fails to reflect equipment deratings, sub-optimal operating performance, and the economic value of the output from individual plants. These factors are reflected by a performance measure such as equivalent availability. For example, a unit that is available but which has been derated might be 100 percent available under the system availability measure. Under the equivalent availability measure, however, this unit would not be considered to be 100 percent available.

Although the AIP appears to be working well in Michigan, an AIP-type program does not seem to be well-suited for adoption by FERC. Specifically, monthly hearings on purchased power and in-depth regulatory reviews of a company's maintenance practices and expenditure levels are essential to the AIP. Furthermore, availability targets must be set to reflect the specific generation mix of the company. To meet this requirement, FERC would have to carry out system-specific evaluations to establish performance standards. Due to the administrative complexity and workload involved, the AIP approach does not appear practical for FERC.

Target Performance Areas

The AIP focuses on optimizing the availability of generating units. The performance measure is a specified scale of system-wide generator availability. Under the AIP, system availability is determined by following the East Central Area Reliability (ECAR) method. For a single generating unit, the ECAR method defines availability as the percentage of a time period during which the unit was either operating or available but not operating. Under this method, if a unit is totally out of service for scheduled or unscheduled maintenance, it is considered to be unavailable. If the unit is operating, or is capable of being operated either at its full rated capability or at a level less than its full rated capability, it is considered to be available. A utility's system availability is derived by summing the availability of each unit weighted by its rated capability.

In 1980 the PSC added a periodic outage factor to the availability scale because it believed that the original scale did not provide sufficient incentives to increase system availability. Specifically, it was thought that the incentive mechanism, as originally designed, could lead utility management to defer scheduled maintenance in some instances. However, the intent of the mechanism was not to discourage planned maintenance, but to reduce random outages. To resolve this potential problem, the PSC selected the periodic outage factors for the companies based on an average level of periodic maintenance consistent with each company's history and projections (seven percent for Detroit Edison and nine percent for Consumers Power). These factors are added to the companies' system availabilities, as calculated under the ECAR method, to determine their overall system availability.

Rewards and Penalties

In designing the AIP, the PSC originally set the reward/ penalty scale using 85 percent system availability as the target. The PSC was of the opinion that a utility system with a high availability would have lower customer bills than a system with relatively low availability. The PSC also recognized that a high availability of low-cost generating units (primarily baseload units) reduces fuel and purchased power expenses. In the short-run, sustained high unit availability minimizes reserve requirements, which reduce operating costs and, hence, customer bills.

The AIP currently embodies an assymetrical system of rewards and penalties. Specifically, a company can receive an increase of up to 50 basis points in its allowed return on common equity for generating availability in excess of the present target level. The maximum penalty a company can receive is a decrease of up to 25 basis points in its allowed return on common equity for generating availability below the present target level (see Exhibits A.1 and A.2). Utilizing the current scale of adjustments, for example, the maximum reward that Detroit Edison can receive is $15 million.

During the first week in April of each year, each company is required to file testimony with the PSC indicating its average system availability for the preceding calendar year. When a change in the company's allowed rate of return on common equity is indicated, customer charges or credits are determined by incorporating the adjusted return into the company's most recently PSC-approved capital structure. The resulting change in the overall rate of return is applied to the company's rate base to determine the increase or decrease in its allowed income and the revenue recovery adjustment. The revenue recovery adjustment is either a credit or an increase, in mills per kWh, determined by the kWh usage for the calendar year for which the system availability has been achieved.

Administrative Requirements

The implementation and administration of the AIP has required substantial commitments of both PSC and company manpower resources. Specifically, the PSC estimates that between 1.5 and two person-years are required to monitor each company's operations. The companies have also

Exhibit A.1

AVAILABILITY INCENTIVE PROVISION FOR DETROIT EDISON

System Availability (%)[a]	Return on Equity Adjustment (%)
92.01 - 100.00	+0.50
90.76 - 92.00	+0.40
89.51 - 90.75	+0.30
88.26 - 89.50	+0.20
87.01 - 88.25	+0.10
81.01 - 87.00	0
80.01 - 81.00	-0.05
79.01 - 80.00	-0.10
78.01 - 79.00	-0.15
77.01 - 78.00	-0.20
0.00 - 77.00	-0.25

SOURCE: Roach, E. M. and Tarletz, D. B. The Application of Generating Plant Performance Standards in Ratemaking Proceedings--An Update. Paper presented at the Edison Electric Institute Legal Committee Meeting, Spring 1982, Attachment E.

a. Includes periodic outage adjustment factor.

Exhibit A.2

AVAILABILITY INCENTIVE PROVISION FOR CONSUMERS POWER

System Availability (%)[a]	Return on Equity Adjustment (%)
94.01 - 100.00	+0.50
92.75 - 94.00	+0.40
91.51 - 92.75	+0.30
90.26 - 91.50	+0.20
89.01 - 90.25	+0.10
83.01 - 89.00	0
82.01 - 83.00	-0.05
81.01 - 82.00	-0.10
80.01 - 81.00	-0.15
79.01 - 80.00	-0.20
0.00 - 79.00	-0.25

SOURCE: Ibid.

a. Includes periodic outage adjustment factor.

increased their maintenance and plant operations staffs. In addition, the AIP requires that an annual hearing be conducted to determine system availability and related rewards or penalties. To date, the hearings have been straightforward and without major disagreement between PSC staff and the companies. However, should the PSC staff and a company disagree on the calculation of system availability, the hearing could become burdensome. In addition, the PSC must have technically-capable staff available to calculate system availability and, more important, to monitor company generating unit performance.

UTAH: UTILITY EFFICIENCY PROGRAM

In 1979 the Utah Public Service Commission (PSC) directed its staff to develop and implement a regulatory incentive program, the Utility Efficiency Program (UEP). Implementation hearings for Utah Power and Light Company, the only utility covered by the incentive program, are scheduled to begin in the fall of 1982. The objective of the program is to encourage the utility to improve its overall efficiency, rather than concentrating on only one particular aspect of utility efficiency. Moreover, the UEP is a reward-only mechanism based on the presumption that monetary incentives might induce increased efficiency levels. For the most part, rewards under the UEP will be based on a "results only" measurement approach, without a specific identification or analysis of the factors contributing to the results.

Conceptually, the Utah UEP program provides a broad and consistent set of incentives for efficient management. Moreover, it addresses the requirement to balance decisions and cost control efforts across functional areas. Unlike incentive mechanisms which embody a penalty, the Utah UEP avoids the problem of further reducing earnings and adversely affecting the cost of capital when efficiency targets are not met.

The Utah approach, which is still under development, faces two drawbacks. First, the approach creates significant measurement problems. Many of the measurement difficulties concerning total factor productivity indexes arise with the UEP: for example, how should a baseline data set be established and what types of deflators are appropriate for various cost items (see Appendixes B and C for a detailed discussion of these measurement problems). Second, the UEP may not properly account for productivity changes that are beyond the control of management, such as step increases in fuel prices that make existing plants obsolete or changes in environmental regulations that increase the company's investment cost per unit. An additional estimation problem also warrants attention. Specifically, the regression model used in the UEP embodies the assumption that the changes a utility makes to improve its efficiency within a functional area of its operations will not negatively affect the quality of service to its customers. As we pointed out in Chapter 2, performance improvements in one area of a utility's operations may be achieved without improving, and possibly hurting, the utility's overall performance.

Because the UEP has not yet been implemented, it is too early to assess the feasibility of implementing its regression model approach at the FERC level. However, it is clear that a major initial effort would be required by FERC to establish this approach. Moreover, the administrative burden of operating the program on an ongoing operational basis cannot be determined at this time.

Target Performance Areas

Because the UEP is concerned with overall utility efficiency, it focuses on all major areas of utility operations and decisionmaking. The PSC chose to group the company's activities into four functional areas:

- Generation investment,
- Transmission, distribution, and general investment,
- Power production expenses, and
- Service expenses.

The proposed UEP involves adopting a performance measure for each functional area and then establishing baseline values of the measures (i.e., values that represent a "normal level of operating efficiency"). The measures selected for the functional areas are shown on the next page.

UEP PERFORMANCE MEASURES BY FUNCTIONAL AREA

Functional Area	Measure
Generation investment	\$/MW
Transmission, distribution, and general investment	\$/Customer
Power production expenses	¢/MWh
Service expenses	\$/Customer

To establish a baseline value for each measure, the PSC is considering two approaches. The first approach involves using a regression model to project each measure based on the past 13 years of operating data for the company. This model has been developed by the PSC. Alternatively, the PSC is considering using a national average or an average of a selected subset of utilities to establish the baseline values.

Rewards and Penalties

The UEP encompasses a reward mechanism based on the assumption that monetary incentives might possibly induce higher efficiency levels, beyond what might otherwise be expected. The PSC assumes that Utah Power and Light has achieved a level of efficiency that is "just and reasonable." Therefore, the purpose of the incentive mechanism is to induce improved efficiency over current or baseline levels. There are no penalties for performance at or below baseline levels.

Whether a reward is warranted is determined by comparing the company's actual performance in each functional area with the baseline measure. The differences between actual and baseline costs, multiplied by the appropriate unit (e.g., MW or MWh) are then summed to determine if an overall efficiency gain resulted. If the utility simply maintains its historic level of efficiency (assuming that the baseline efficiency values are based on the company's historic efficiency patterns), the UEP will indicate that a reward is not warranted. However, if the firm's efficiency has been improved, as indicated by the measures, a reward will be granted.

The UEP is designed to split the savings stemming from efficiency improvements between the utility and its customers. The PSC has yet to determine the proportional distribution of these efficiency gains. An equal split has been proposed, but the utility points out that, under such an arrangement, approximately 50 percent of its share will be decreased by federal taxes. The company proposes that the benefits be split on a 2:1 basis, under which the utility will receive two-thirds of the benefits and customers one-third. The company contends that under such an arrangement, each party would share equally on an after-tax basis.

Administrative Requirements

The UEP has required significant PSC staff and utility time to develop the model. Moreover, a significant level of effort will be required to fine-tune and implement the UEP. After the UEP becomes operational, the informational and manpower resources required to operate the program are likely to be manageable, especially if the baseline values are determined by using the company's historical operating data.

APPENDIX B

EVALUATING THE USE OF TOTAL FACTOR PRODUCTIVITY ANALYSIS AS A BASIS FOR INCENTIVE REGULATION

In a utility's production process, a number of different factor inputs (i.e., labor, fuel, capital, purchased power, and other materials) are combined to produce outputs. Total factor productivity (TFP) analysis provides a means of measuring the efficiency, over time, with which these inputs are combined in the production process. When compared to partial productivity measures or disaggregated unit cost measures, which focus on only one or a few inputs to the production process, TFP analysis is deemed theoretically superior because of its comprehensiveness.

TFP analysis also avoids the major problem in interpreting partial productivity analysis, where productivity is indicated by measuring a utility's total output relative to one factor input. If a utility inefficiently substitutes other factor inputs in the production process for the input being measured by the partial productivity analysis, it may be interpreted that the firm has improved its measured productivity. However, the "improvement" will have been obtained by consuming less of the focal input and more of the substitutable inputs than would be under a least-cost production program. The corollary of this problem is that under an incentive regulation program based on partial productivity or unit cost measures, a utility will be encouraged to substitute, perhaps inefficiently, other inputs for the input that is the subject of the incentive mechanism.* However, because TFP measures use several weighted factor inputs, their use should alleviate the potential adverse incentives associated with regulation that is based on narrowly defined partial productivity or unit cost measures.

In addition to its strengths relative to partial measures of productivity, TFP analysis offers certain theoretical advantages to aggregate measures of firm performance such as revenues or total cost per kWh of electricity sales. In particular, TFP analysis provides a procedure for valuing disparate inputs over time on a common, constant dollar basis. TFP analysis also provides a more precise procedure for valuing the input contribution over time from a firm's capital stock.

However, despite its theoretical advantages, the use of TFP measures presents significant methodological, conceptual and practical problems which, we believe, will prevent TFP from being accepted in the foreseeable future as a basis for incentive regulation. These problems concern both the practicality of using a complex, theoretical tool as a basis for regulation and fundamental uncertainties in the design and application of a TFP analysis. Indeed, the experience to date with the use of TFP analyses in the electric utility regulatory setting has shown that

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* This problem can be addressed by having more than one incentive mechanism in place; the incentives would be based on different partial productivity measures that presumably balance out the adverse effects associated with a mechanism oriented to any one input. However, a problem still remains in deciding how to weight the reward/penalty structure associated with the different input measures so that the firm receives efficient productivity signals. TFP analysis addresses this problem implicitly by using the prices of the factor inputs as the weights in measuring aggregate productivity performance. If the prices of factor inputs are set competitively, then the prices will be the correct weights for encouraging a utility to combine its factor inputs efficiently.

regulators, utilities, and intervenors have engaged in considerable argument over the validity of TFP analysis as a basis for regulation (see Appendix C). On balance, we conclude that the net result of these debates and the associated legal contests is to prevent TFP analysis from serving as a viable, practical basis for incentive regulation.

In the following sections, we examine the use of TFP analysis as a potential basis for incentive regulation. First, we briefly discuss the theory of TFP analysis, and outline some of the methodological difficulties concerning its use. Second, we discuss the conceptual and practical difficulties involved in using TFP measures as a basis for incentive regulation. As part of this section, we also review the regulatory proceedings concerning two electric utilities' experience with the use of TFP analysis.

CONCEPT OF TFP ANALYSIS AND METHODOLOGICAL PROBLEMS

The term "TFP analysis" applies to several methodologies for analyzing the efficiency of the production process in a firm, industry, or economy. Two of these methodologies are the "exact index number" approach for measuring productivity, and the econometric estimation of production cost functions and comparison of actual and predicted costs. Both contain a number of alternative methodological possibilities, whose use, for example, is determined by the assumed functional form of the underlying production function. The following discussion applies most strictly to the exact index number approach, which has been used most frequently to date in TFP analyses of the electric utility industry. However, most of the methodological difficulties cited for the exact index number approach (e.g., measurement of capital stock) have parallel difficulties in the other TFP approaches.*

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* Our discussion does not purport to be a detailed theoretical exposition of TFP analysis. Rather, we provide only sufficient background to support our findings concerning the viability of TFP analysis as a basis for incentive regulation. For an excellent discussion of the theory of TFP analysis, see: Diewert, W. Erwin. "Theory of Total Factor Productivity Measurement in Regulated Industries." Productivity Measurement in Regulated Industries. Edited by Thomas Cowing and Rodney Stevenson. New York: Academic Press, Inc., 1981.

Theory of TFP Analysis

In a TFP analysis of an electric utility, an index of the firm's real value of production outputs relative to its real value of inputs is computed and may be tracked over time. To eliminate the effects of inflation on the measurement of changes in productivity, the value of both inputs and outputs is expressed, inasmuch as possible, in physical, non-dollar denominated units or in deflated, constant dollar units. Typically, a TFP measure for a specific time period (e.g., a year) would consist of a numerator of production (output) and a denominator of inputs to the production process. If there were only one output and one input in a production process, and they did not change qualitatively over time, a productivity index could be developed by simply dividing the physical quantity of output by the physical quantity of input. A comparison of these quotients across time periods would indicate the change in productivity for the firm over time.

However, in an electric utility's production process, there are a number of disparate inputs: labor, capital, fuel, purchased power, and other materials. An electric utility may be viewed, albeit somewhat simplistically, as having only one homogeneous output: energy measured in kilowatt-hours (kWh). However, like input, output is not purely homogeneous because of the differences in production processes and cost per unit of production for generating output for different service classes. Accordingly, at a minimum, output should be differentiated among the different customer service classes.

TFP analysis provides a means for aggregating over these disparate inputs and outputs in measuring an electric utility's productivity. Specifically, the generic form of a TFP measure is:

$$TFP = \frac{\sum_{j}^{M} w_j \cdot Q_{j,t}}{\sum_{k}^{N} w_k \cdot I_{k,t}}$$

where the numerator represents the value of production, Q, in period t and the denominator represents the value of inputs, I, in period t. As stated above, Q and I would be measured in physical or constant dollar units. The aggregation process represented by the formula is a simple arithmetic sum using the linear, multiplicative weights w_j and w_k. The weights are critical because they describe how to combine the disparate measures of input and output. In the earliest and simplest form of TFP analysis, the Laspeyres weighting technique, the weights are simply the prices of the inputs and outputs in a specified period of analysis, typically the initial period.*

This procedure implicitly assumes that, and is precise only if, the prices of the different outputs, relative to each other, and factor inputs, relative to each other, are constant over the period of analysis (i.e., the absolute levels of prices may change, but the relative relationships of one to the other must stay constant).

More recently, productivity theorists have recognized the unreasonable restrictiveness of the assumptions underlying the Laspeyres process and have developed less restrictive aggregation methodologies. At present, the aggregation methodology most often used in productivity studies is a discrete approximation to the Divisia aggregation method (typically a Tornqvist approximation).** The Divisia method recognizes that relative prices are not constant over time and is based on the continuous measurement of the prices and quantities of inputs and outputs.

Once a value has been computed for a number of time periods, the productivity performance of the firm over time may be analyzed by computing the ratios of the TFP value for a specific year(s) relative to the base year (or depending upon performance, the immediately preceding year):

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* For example, see: Kendrick, J. W. Productivity Trends in the United States. Princeton, N.J.: Princeton University Press, 1961.

** Diewert, op. cit.

$$\frac{TFP_{t+1}}{TFP_t}, \quad \frac{TFP_{t+2}}{TFP_t}, \quad \ldots, \quad \frac{TFP_T}{TFP_t}$$

These index values indicate the firm's productivity performance in a time period relative to the performance in the base (or other) period. A ratio value greater than one indicates productivity improvement, a value less than one indicates deterioration, and a value equal to one indicates no change.

Methodological Difficulties of TFP Analysis

In theory, TFP analysis offers an approach for comprehensively measuring the change over time in the production efficiency of providing electricity. Because it includes all factor inputs (in varying degrees of aggregation) in the productivity measure, if it is used in an incentive regulation program, there would be no incentive for a firm to alter its mix of factor inputs so that an inefficient mix results.

However, TFP analysis contains a number of methodological difficulties. For the most part, these difficulties involve aspects of TFP measurement which have no clear theoretical justification for selecting a specific methodological treatment. Because the findings for a utility regarding productivity improvement may vary depending upon the specific formulation of the analysis, it becomes difficult to accept TFP analysis as an objective basis for measuring productivity in an incentive regulation program.

Measuring Inputs/Output

Among the important problems in applying TFP analysis to an electric utility firm is the management of inputs (typically defined to cover the following categories: capital, labor, fuel, purchased power, and materials). Each category presents its own special problems, which we illustrate in the following paragraphs.

The measurement of the capital input is perhaps the most difficult and contentious aspect of TFP analysis. This measurement involves two steps: first, measuring the capital stock at a point in time; and, second, imputing the input contribution from the capital stock during a period of time. The problem with measuring capital stock is that of collapsing into a single number the results of capital formation activities that may have occurred over a period as long as 30 or 40 years. The capital purchases over this period represent widely different vintages and will almost certainly reflect different fuel technologies and technical operating capabilities. The typical solution to this problem is to measure capital inputs in constant dollars by accumulating, through each year of the analysis, the deflated net additions to capital for the previous year. Net additions are defined as capital additions (e.g., installing a new generating unit) less retirements. The index commonly used to deflate net capital additions is the Handy-Whitman Index, which provides an inflation adjustment for an aggregate bundle of capital equipment expenditures.

This procedure for estimating the value of capital stock at a point in time has a number of problems. First, deflating widely different kinds of capital expenditures by the same factor at best adjusts haphazardly for inflation. Second, the constant dollar deflation cannot capture advances in capital-related technology. Third, the analyst must inevitably choose some year to begin the accumulation of net capital additions; at this point in the analysis, the constant dollar value of capital additions prior to that time must be approximated. Analysts have used several approaches for estimating the starting point for capital stock; none would appear to be theoretically dominant over the others.

Problems are also present in imputing the input contribution from capital over a specific time period. The typical approach for a year is to first, sum the estimated cost-of-capital to the firm and the average depreciation rate for the firm's plant and equipment, and, second, multiply this sum by the capacity utilization rate for the firm's equipment. This value is then multiplied by the estimated capital stock for that year. The chief problem here lies in in the depreciation rate, which should reflect the actual physical deterioration of capital equipment resulting from its use during the year. However, depreciation is typically calculated as a straight-line percentage over the estimated life of plant and equipment. The straight-line percentage may bear little relationship to the actual pattern over time of equipment deterioration.

These problems in capital input measurement are especially crucial for the electric utility industry, because it is so capital intensive. Applying different methods to determine capital input may result in different absolute and relative (to other firms) findings regarding the productivity performance of a firm, with corresponding implications for regulatory treatment under an incentive regulation program. (See Appendix C for a review of TFP analyses that have applied different approaches to the problem of capital measurement, which in some instances have resulted in different analytic findings for the same company.)

Measuring the labor input is somewhat more straightforward. The annual total hours of employee service are used as the physical unit and the TFP weight is developed from deflated average hourly labor costs. However, analysts differ over the definition of the labor base (i.e., should it be total electric department employees or total operating and maintenance employees?) and the appropriate labor cost (e.g., should it include benefits, payroll taxes, etc.?). Again, such differences may lead to different productivity findings for a firm. An additional problem lies in adjusting for the quality of labor inputs: changes in labor costs over time may result from inflation or the substitution of more productive, but more expensive, labor for lower quality labor in the production process. A failure to account for such differences may result in erroneous measurements of the change in productivity.

The fuel input would perhaps be the simplest input if a company used only one homogeneous fuel in all of its generating units. In this case, the physical unit of measurement would be Btu. However, when different fuels are used, particularly nuclear and fossil, there is no clear-cut way to aggregate them into a single fuel measure. Some analysts have tried to assess Btu-equivalent purchases of all types of fuel inputs in a year, while others have calculated the fuel purchases in each year in constant dollars by using a fuel cost index.

Purchased power creates a similar problem to fuel, in that it is a heterogeneous input: both the mix and average price of the company's purchased power transactions may vary considerably from year to year. Again, this raises the problem of how to translate purchased power expenditures into a meaningful homogeneous input measure that is consistently valued over time.

The final input category, materials, is typically measured as a residual. For a given year, the materials input is measured by deducting the costs associated with all the specifically identified input categories (i.e., labor, capital, fuel, and purchased power) from the total input cost. The remainder is, by definition, a hodgepodge that may vary considerably in composition from year to year. Some composite inflation index, such as the wholesale price index, is then used to deflate this residual to a constant dollar amount. However, it is not clear that the commodity bundle represented by any of the commonly used indexes bears any stable degree of correspondence to the composition of the materials residual.

The measurement of output in TFP analysis creates an additional set of difficulties, even when the firm is what economists call a "single product" firm such as an electric utility. Generally, in productivity studies of utilities, the kilowatt hours of electricity sold are measured and then used as the numerator in the TFP ratio. Several problems arise with this procedure. First, simply measuring kilowatt-hours output ignores the company's load factor, which may or may not be under the company's control. To the degree that they are beyond management's control, load factor shifts can substantially affect input use without having any effect on kWh measures of output. Thus, an exogenous factor can very much affect measured productivity performance, which is not desirable if TFP is used to measure management efficiency. Second, it may be legitimately argued that energy output, even when segregated by service class, is not strictly a homogeneous commodity; rather, it varies over time on the basis of service reliability or other qualitative aspects of utility customer service.

External Factors

Another area of methodological difficulty concerns accounting for factors that are beyond management's control. In addition to the variations in load factor mentioned above, controlling for the valuation of output and differential access by firms to economies of scale can influence the measurement or specification of output.

A general assumption in conducting TFP analyses is that input and output prices are determined in competitive markets. While it may be true that input prices are competitively determined, most output prices (which become important in weighting output that has been segregated by class of service) are set by regulators.* Accordingly, the stringency of a regulatory constraint may influence the apparent level of productivity achieved by a firm, both across time (if the stringency of regulatory policy varies over time) and, particularly, across firms (if firms are subject to different degrees of regulatory stringency). The simplest way to address this problem would be to treat energy as a homogeneous commodity and, therefore, eliminate the requirement to use price information in aggregating disparate output categories. However, then the problem of output being heterogeneous over service classes would be revived.

The second external factor, differential access to economies of scale, is also problematic. If this factor is not controlled for in a TFP analysis, a regulator may impute a productivity improvement to managerial acumen when, in fact, the improvement resulted from the increased exploitation of economies of scale as the utility's scale of operations increased. Some analysts (see the Cowing, Stevenson, and Small article discussed in Appendix C) have attempted to control for differential access to economies of scale. However, the econometric analyses required to estimate an economies of scale adjustment factor compound the general problem by adding statistical uncertainty to the methodological uncertainties already inherent in the TFP analysis.

These methodological issues alone are sufficiently complex to embroil administrative law judges in disputes that are far beyond their ability to understand. The issues involve econometrics, economic theory, and detailed knowledge of the operating characteristics of electric utilities. Faced with experts who disagree profoundly on how these issues should be resolved, judges have, in the past, thrown up their hands and refused to resolve the issue, a decision which is not altogether unpredictable or unreasonable.

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* An exeption would be interchange prices that are determined by, for example, a split-savings pricing formula.

DIFFICULTIES IN APPLYING TFP ANALYSES AS A BASIS FOR INCENTIVE REGULATION

There are considerable conceptual and practical difficulties in applying TFP analysis as a basis for incentive regulation. To a degree, these difficulties stem from the methodological uncertainties discussed in the previous section. For example, if different methodological treatments will give different results for a firm's productivity performance (measured absolutely or relatively to other firms or the firm's own productive history), then the opportunity is raised for debate over the specification of a TFP analytic methodology. Regulators, utilities, and intervenors will each have the incentive to manipulate the specification of the methodology to favor their own interests, which will often be at odds. In all likelihood, the resultant legal entanglements cannot be objectively resolved. This section discusses some of these difficulties and reviews the use of TFP analyses in two regulatory proceedings.

Conceptual and Practical Difficulties

If TFP analysis is to be used as a basis for incentive regulation, it will be used in order to give consumers some share of the benefits of a utility's productivity advancement in providing electricity. This could be done by projecting, over the period of a future test year, some level of TFP advancement for the regulated firm. This projected rate of advancement would then be embodied in the rates set for the firm during that year. In this case, the firm will be able to earn its allowed rate of return only by achieving the previously imputed productivity advance, which accordingly should provide an incentive for efficiency.

The question then arises of how the regulatory commission is to determine a "reasonable" expectation of achievable productivity advance for the utility. There are at least two approaches to this issue, each of which is fraught with difficulty:

- Project a reasonable expectation for TFP improvement based on the company's recent productivity performance, or

- Project a reasonable expectation for TFP improvement based on the recent productivity experience of comparable utilities.

The more common of these two alternatives is to use the company's own measured TFP history as a basis for incentive regulation. One difficulty which inevitably arises is deciding upon which past trend to project. To illustrate, assume that the company's 10-year average TFP increase has been three percent, its five-year average TFP increase has been one percent, and its most recent year's experience was minus one percent. Which of these three historic experiences should the regulatory commission use as a reasonable expectation of what the company can achieve in the future? Even if the productivity history of the company is steady, it still may be unreasonable to expect the same trend to continue into the future. On occasion, companies have argued that since the productivity achievements that comprise this trend have all been accomplished (which is why the trend exists), fewer productivity targets will be available in the future. Therefore, they contend that the trend cannot continue to be achieved. Whether or not one is convinced by these arguments, it should be apparent that there is no strong theoretical basis for projecting past productivity improvements into the future.

An alternative to using the company's own history is to use the recent history of "comparable" utilities. The major difficulty in this case lies in choosing this "comparable" group. No two utilities are exactly alike, and there are always unique factors affecting the productivity achievements of any individual firm. Objectively adjusting the TFP measure for these different unique factors is probably impossible. As a result, the issue of comparability will likely be fought in a regulatory proceeding with little chance for objective resolution.

In addition to these problems is the practical consideration of the cost of building and implementing an incentive regulation program that is based on TFP analysis. If FERC or other regulatory bodies should decide to use TFP as a basis for incentive regulation, the administrative costs can be expected to be quite large. The first step in implementing such a program would be to undertake a generic hearing to establish a set of productivity measurement guidelines that will be used in subsequent legal proceedings. These generic hearings could be carried out at many different levels of intensity, with correspondingly different levels of cost. At the very minimum, a generic hearing designed to establish a set of rules regarding the use of TFP analysis in rate cases or for managerial efficiency uses would require at least seven man-years of effort. Using a conservative estimate, approximately 25 percent of this effort would be clerical, 15 percent would be for data gathering, and the remainder would be for the economists and econometricians required to resolve the difficult methodological issues described at the beginning of this section.

The next question is what level of effort would be required to staff an ongoing productivity analysis. This, of course, depends on how often data (on company outputs and inputs) are provided to FERC, as well as the level of detail and frequency with which the TFP analysis must be updated. As a basis for estimating costs, we have assumed that data would be provided to FERC annually by a number of firms, and that FERC will estimate the annual TFP level for each utility, and compare it with the levels of other utilities or with each company's own history. If this is the case, the steady-state level of effort should be approximately one person for each four utilities. This person would be an analyst with both economic and computer programming skills; the person would transfer the data provided by a company from its accounting form into the form necessary for TFP estimation. In addition, there would be at least one supervisor to direct these analysts and resolve the difficult methodological issues that would certainly arise.

TFP Analysis in Regulatory Proceedings

In this section, we review the experience with the use of TFP analysis in two electric utility regulatory proceedings: Consolidated Edison Company (ConEd) of New York, Case No. 27353 before the New York Public Service Commission, 1976; and Public Service Company of New Mexico, Case No. 1419 before the New Mexico Public Service Commission, 1978. In both proceedings, considerable argument was addressed to the validity of using TFP analysis as a basis for incentive regulation: in the end, the regulatory authorities did not accept its use as an objective basis for ratemaking. The experience of these two proceedings illustrates the likely response by utilities, regulators, and intervenors if FERC were to attempt to administer a TFP-based regulatory program on a broad basis. Moreover, most of the methodological and practical issues discussed above were faced in these proceedings.

Case No. 27353 was the special TFP portion of a larger ConEd rate case* and involved three main participants: the Consumer Protection Board (CPB)(an intervenor), Commission Staff, and ConEd. The CPB argued that the use of TFP analysis was necessary if regulation were to avoid a simple cost plus operation; that TFP was not significantly more complicated than, for example, load forecasting; and that it could be useful as a forecasting tool once modifications were made. The CPB asked that all New York utilities be required to participate in an extensive productivity measurement exercise. As part of its intervention effort, the CPB presented Dr. Rodney Stevenson as a witness. Stevenson's testimony contained a TFP analysis that he had undertaken on ConEd for the years 1964 to 1973. Stevenson found that, during this interval, ConEd had achieved an average annual rate of productivity increase equal to 1.26 percent.

The Commission Staff was more apprehensive about the use of TFP analysis as a basis for incentive regulation. In its favor, they argued that productivity analysis was useful: in analyzing a company's rate case submission, in determining the productivity performance that the company is assuming for the future, and as a starting point for further analysis of why a projected productivity change will take place. However, the Commission Staff conceded that it could only be presumed that past productivity gains are achievable in the future. Specifically, Staff stated that if the company has assumed that its past productivity gains are not achievable in the future, "it is incumbent upon the company to show the commission why that is so and why an increased amount of resources per unit of output is inevitable and a proper basis for establishing revenue levels."** Moreover, Staff concluded that TFP analysis is not a

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* Appendix C contains a review and discussion of testimony by three witnesses which dealt with TFP analysis for ConEd.

** Testimony of Mr. Frank Berak in Case No. 27353.

panacea for all rate case cost projection issues and that TFP techniques are not sufficiently well developed to be used with great confidence. The Staff argued that at present, TFP analysis is useful primarily as a diagnostic tool. As part of its case, Staff presented a witness, Mr. Ralph E. Miller, who had undertaken a TFP analysis for ConEd over the period 1967 to 1975. Although his methodology was largely similar to Stevenson's, Miller's TFP methodology deviated in several respects. On the basis of his analysis, Miller found that ConEd's productivity had deteriorated at an 0.39 percent average annual rate during the period 1967 to 1975.

ConEd responded to the CPB and Staff positions by arguing that it needed no further incentives for managerial efficiency: because the firm had been unable to earn its allowed return in the recent past, it already had every incentive to be efficient. In addition, ConEd argued that TFP analysis is too aggregate, and that any adjustment to the company's projected cost should come only after an in-depth analysis of the budget or cost items in question. ConEd's principal witness in this area was Mr. William J. Murphy. Murphy had not undertaken a TFP analysis for ConEd; instead, he had analyzed the efforts by Dr. Stevenson and Mr. Miller in detail. Murphy identified a number of differences in the methodological approaches followed by Stevenson and Miller, as well as what he felt to be some fundamental errors in their analytic approaches or use of data. On balance, Murphy (and ConEd) concluded that TFP methodology was too immature to be applied in such an important setting. In particular, Murphy argued that TFP analysis is not well enough defined to point to a specific methodological approach that could be relied upon to give objective, accurate findings regarding managerial performance. Moreover, Murphy argued that it is not possible in a TFP analysis to control adequately for the factors used to measure productivity that are beyond management's control.

As the outcome of this case, the New York Commission essentially adopted the administrative law judge's recommended decision, which we reproduce below:

> 1. The influences upon the operation of a major utility are too complex for single-number, input-output ratios to have much meaning; disaggregation (of factor inputs) will not cure this problem.

2. Any productivity adjustment must be inherently arbitrary; there is no way to forecast productivity gain in a given future year with any degree of confidence.

3. TFP represents a misguided effort to achieve great precision as to one small aspect of highly imprecise rate determinations.

4. Rather than serving as an aid to forecast evaluation, TFP would entail a diversion of effort, complicating rate cases instead of making them easier to resolve.*

The use of TFP analysis in regulation has been considered, to a more limited degree, in at least one other case: Public Service Company of New Mexico (PNM), Case No. 1419. In this case, a number of witnesses presented testimony concerning TFP analyses in arguing whether or not the New Mexico cost of service indexing procedure had affected PNM's incentives to maintain production efficiency. The witness retained by the Attorney General utilized partial factor productivity techniques to analyze this issue. The witness retained by the Commission Staff, Dr. Rodney Stevenson, presented a TFP analysis for PNM before and after the adoption of the cost of service index. PNM presented one witness who analyzed the utility's total factor productivity, one witness to rebut the testimony of the Attorney General's witness, and several witnesses who testified generally on PNM's productivity performance since cost of service indexing had been adopted.

The cross-examination and rebuttal testimony concerning the partial factor and TFP analyses became excessively technical in this case. Many of the issues discussed in the methodology section above were addressed, with almost no agreement among the various witnesses on a reasonable approach. Predictably, the Commission in this case was overwhelmed by the disagreement among well-trained, rigorous economists. Reflecting this bewilderment, the Commission concluded "without going into the specifics of each witnesses' testimony, we believe that

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* Page 49 of the decision of Judge Frank S. Robinson.

both Dr. Stevenson's and Kumar's (the Attorney General's witness) analyses are subject to valid criticisms. This is due in part to the failure of the regulatory community to develop reliable productivity measures." Understandably the Commission was not able to resolve the disagreements. In the end, the productivity testimony had no effect upon the Commission's ultimate decision in Case No. 1419.

APPENDIX C

REVIEW OF TOTAL FACTOR PRODUCTIVITY STUDIES IN THE ELECTRIC UTILITY INDUSTRY

As part of the evaluation of the use of total factor productivity (TFP) analysis as a basis for incentive regulation, we reviewed six documents: five of the documents are TFP studies that have been conducted on electric utilities; the sixth is a critique of the use of TFP analysis in a regulatory setting. These studies were reviewed in order to understand the specific TFP methodologies that have been applied in studies of electric utility productivity; to gain insight into the difficulties of applying the different TFP methodologies; and, since several of these studies were presented in the context of a regulatory proceeding, to gauge how regulators, utilities, and intervenors might respond to the use of the TFP analyses as a basis for incentive regulation.

An Aggregate Productivity Measurement System with Planning Implications for Ontario Hydro, December 1978

The economics division of Ontario Hydro (OH) implemented an ongoing program to track productivity in the utility's operations. The OH program is designed to help management assess OH's productivity performance over time and to provide an explicit basis for factoring expected changes in productivity into its projected revenue requirements, or alternatively, estimating the productivity change embodied in the utility's projected revenue requirements.

OH applies two methods to measure productivity. The first is conventionally defined total factor productivity (TFP), using a measure of the gross value of production in the numerator. The second method is a value added measure of productivity using value added as the numerator in the TFP analysis. In its report OH noted that while the value added approach has been used to facilitate the comparison of index numbers with certain statistical series published by the Canadian government, it found that the gross value method of measuring TFP is more theoretically sound. The following comments pertain to the conventionally defined (gross-value) TFP measure.

To measure TFP, OH uses the Laspeyres, or fixed initial price, weighting procedure for combining factor inputs. The factor inputs included in OH's analysis are labor, capital, purchased power, water rentals (OH relies heavily on hydroelectric generation), fuel, and other expenses. OH's version of TFP analysis differs from the more commonly used approaches in several respects. First, constant dollar revenues from electricity sales plus other income (primarily, interest earned on working capital) is used as the measure of the value of production (conventional TFP analyses would not include the interest income because it does not relate to the production of electricity). Second, the measure of capital stock includes constant dollar working capital (which would not normally be included) as well as a conventional constant dollar measure of physical capital stock. Third, no adjustment is made for capacity utilization in estimating the capital input in any year.

We believe that such divergences from the more commonly used approaches to measure TFP may create measurement biases. For example, including working capital in capital stock and not adjusting for capacity utilization may lead, in any year, to an over-or under-estimation of the input contribution from capital compared to the value that would be indicated by more conventionally applied analytic methods. Including interest income in the measure of the value of production may confound the analysis of OH's productivity performance in providing electric service to its customers.

As in all TFP analyses, OH is attempting to measure the change, over time, in the efficiency with which factor inputs are combined to produce output. However, OH does not adjust its analysis for any factors, except inflation, that are beyond management's control. Rather, in interpreting its TFP program results, OH attempts to distinguish between planning and operating productivity. The utility stated that, in the short-run, the contribution from capital-related factor inputs cannot be affected by management; hence, the effect of these inputs on TFP stems from planning decisions made in earlier time periods. Conversely, OH identified changes in TFP that result from short-run variable inputs as being indicative of operational efficiency. Using these notions, OH defined the short-run potential for controlling productivity as the share of the value of factor inputs that is contributed by inputs other than capital in a given time period. Using this analysis, OH found that the "controllability" of productivity increased by 15 percent in the 10-year period ending in 1976. We find this analysis to be simplistic and probably distorted: consider, for example, that "controllability," as defined in OH's analysis, may have paradoxically increased because of OH's inability to control its short-run variable cost.

Testimony of Rodney E. Stevenson
Before the New York State Public
Service Commission, Case No. 27029,
Consolidated Edison Company of New
York, Inc., October 1, 1976

As part of a Consolidated Edison (ConEd) rate case, the New York State Consumer Protection Board hired Dr. Rodney E. Stevenson of the University of Wisconsin to perform a TFP analysis on ConEd for the period 1964 to 1973. After comparing the results of this analysis to similarly calculated results for other utility companies, Stevenson concluded that ConEd had achieved a moderate improvement in productivity relative to other companies.

In computing TFP for ConEd, Stevenson used the Laspeyres fixed initial price weighting procedure for combining factor inputs. The inputs used in his analysis were labor, capital, fuel, purchased power, and a residual category called materials and supplies. Output was measured as total kWh sales to residential, commercial, industrial, and other customers; no distinction was made in the value or cost of service to each customer class.

In most respects, Stevenson's methods for computing input values follow the commonly used approaches in TFP analysis. For example, the deflated capital stock for each year was computed by summing the deflated annual net additions to capital stock throughout that year. Net capital addition was deflated using the Handy-Whitman index.

However, one aspect of Stevenson's methodology, the treatment of purchased power as an input, may be problematic and merits discussion. As the measure of purchased power in each year, Stevenson used net kWh purchases from Account 551 of the FERC Form-1. Account 551 includes both wholesale purchases from other utilities and net interchange adjustments (net interchange is the net sale or purchase of electricity under exchange and pooling agreements). As the weight for the purchased power input, he used the average cost per kWh of purchased power in 1967. There may be conceptual problems with this approach in that net interchange includes interchange sales as well as purchases. Indeed, a utility with large interchange sales (and small interchange purchases) may have a large enough kWh and revenue inflow from net interchange sales so that purchased power (measured either in kWh or in dollars or both) might be negative. In addition, a problem arises in weighting. There is little reason to believe that the average price per kWh of purchased power, relative to the price of other factor inputs, will remain constant over the period of analysis (this assumption is embodied in the use of the Laspeyres indexing procedure). Rather, the average price per kWh for purchaed power could be expected to vary erratically over time as the share of purchased power that is represented by net interchange varies and the actual price for power purchases varies due to changes in the nature or mix of a utility's purchased power transactions.

Stevenson's analysis indicated that ConEd achieved an average annual growth rate in productivity of 1.26 percent per year during the period 1964 to 1973. In estimating this value, Stevenson did not adjust his analysis for any factors beyond management's control except inflation. However, he acknowledged that any of several exogenous variables might affect the apparent growth in productivity achieved by ConEd. These factors include: growth in sales, growth in capacity, growth in per-customer consumpton, changes in customer mix, and changes in capacity utilization.

<u>Testimony of Ralph E. Miller Before the New York State Public Service Commission, Case No. 27029, Consolidated Edison Company of New York, Inc., 1976</u>

In the same ConEd rate case in which Dr. Rodney Stevenson presented a TFP analysis on behalf of the New York State Consumer Protection Board, Ralph Miller presented a TFP analysis of ConEd's performance on behalf of the New York State Public Service Commission. Miller's analysis was directed at measuring ConEd's productivity performance over the period 1967 to 1975.

Miller compared the results from his analysis with similarly calculated performance productivity results for 12 other large utility companies in the Northeast and Midwest. This comparison indicated that ConEd's productivity performance (an average annual decrease of 0.39 percent) fell below the median level of performance achieved by these 12 other companies. Miller used the average performance improvements achieved by these other companies as a basis for recommending that ConEd set a target rate of productivity improvement for future test year ratemaking.

In most respects, the analytic methodology followed by Miller is generally similar to that applied by Stevenson in his analysis of ConEd's productivity. But despite having used similar methodologies, Miller's and Stevenson's findings are substantially different. In measuring TFP for ConEd, both Miller and Stevenson used the Laspeyres fixed initial price weighting procedure for combining factor inputs. The inputs Miller used in his analysis were labor, capital, fuel and purchased power, and materials and supplies. A difference between Miller's and Stevenson's analytic approaches is that, in measuring output, Miller differentiated among the different customer classes served by ConEd. Specifically, Miller computed the average price per kWh sold to each service class in 1974 and used the Laspeyres indexing procedure to calculate a constant dollar value of production for each year in the period of analysis. To the extent that the value and cost of service differ across customer classes, this analytic approach is superior to one that treats all production as though it were a homogeneous commodity.

Like Stevenson, Miller used the net kWh purchases from Account 551 of FERC Form-1 as the measure of purchased power. As the weight for net kWh purchases, Miller also used the average price per kWh that ConEd paid for purchased power. Again, the potential problem with this approach is that purchased power includes net interchange and thus, it cannot be easily interpreted as an input. Also, as before, there is little reason to expect that the relative price of purchased power will stay constant over time. Changes in the purchased power transaction mix could significantly alter the relative average price per kWh for purchased power from year to year.

Minor differences in Stevenson's and Miller's methodologies are present at various points in their analyses. For example, Stevenson and Miller used different mathematical formulas for estimating the real value of plant in service at the beginning of the analysis period. As another example, in estimating the annual flow of capital services, Miller used a single coefficient value for the entire analysis period, while Stevenson allowed the capital service coefficient to vary from year to year.* As a result, presumably, of these differences in analytic approach (and others discussed in our review of the next study, the testimony of William J. Murphy), Miller and Stevenson achieved different findings regarding the rate of productivity improvement for ConEd. Whereas Stevenson estimated that ConEd achieved an average annual rate of increase in productivity of 1.26 percent per year during the period 1964 to 1973, Miller estimated that ConEd's productivity declined at an average annual rate of 0.39 percent for the period 1967 to 1975.

Testimony of William J. Murphy Before the New York State Public Service Commission, Case No. 27029, Consolidated Edison Company of New York, Inc., 1976

In the same ConEd proceeding for which Dr. Rodney Stevenson and Mr. Ralph Miller prepared TFP analyses of ConEd, Mr. William Murphy was retained by ConEd to present a critical comparison and evaluation of Stevenson's and Miller's TFP analyses. Murphy's testimony argued that while Stevenson and Miller applied basically similar approaches to analyze ConEd's productivity performance, their approaches contained a sizeable number of individually minor differences. When taken together, Miller found that these differences led to relatively substantial differences in the overall findings of the analyses. In addition, Murphy pointed out specific problems with the methodologies employed by both analyses. As a result, he concluded that TFP analysis does not provide a sound basis for comparative evaluation of utili-

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* The fourth article reviewed in this appendix, Murphy, provides a detailed delineation of the methodological differences between Miller's and Stevenson's analyses.

ties in a ratemaking procedure and that it should not be used as a basis for prospective ratemaking, as was the intent in Miller's testimony. Whether or not we accept Murphy's arguments, his testimony illustrates the potential criticisms of and reactions to attempts to use TFP analyses in a regulatory process, especially when the concerned parties believe the analyses may not work in their favor.

Murphy cited the following elements of Miller's and Stevenson's analyses as being different, yet within the range of reasonably acceptable methodological treatments:

- Stevenson did not differentiate output by customer class, while Miller did.

- Miller and Stevenson used different methods to estimate the fuel input. To calculate a deflated consumption measure, Stevenson multiplied the utility's final expense by the company's fuel price index as calculated from the FERC publication, Statistics of Privately Owned Electric Utilities. For fossil-fired steam units, Miller attempted to estimate heat rates. For nuclear and non-steam units, he used the actual energy generated as a proxy measure for fuel consumption. The figures for both types of units were weighted by base period prices to yield deflated measures of fuel consumption.

- In estimating the value of labor services, Miller recognized benefits as a component of labor expenses; Stevenson excluded benefits.

- Both Stevenson and Miller treated the materials and supplies input as a residual; however, because of the treatment of other inputs, the composition of materials and supplies was not the same in both studies. For example, by excluding labor benefits from the value of labor services, Stevenson included labor benefits in materials and supplies. This input was then deflated for each year using the Wholesale Price Index; as a result, Stevenson's valuation of labor benefits over time was significantly different from Miller's.

- Miller and Stevenson used different approaches for estimating capital-in-service at the beginning of the analysis period. Stevenson used a 15-year summation formula to estimate initial plant-in-service for 1950 and adjusted incrementally, by year, to estimate capital stock in 1964. Miller used a 20-year summation formula to estimate plant-in-service in 1967 and adjusted incrementally from that point.

- Stevenson and Miller used different procedures for estimating the input contribution from capital stock: Stevenson's measure (as a percentage of the capital stock) varied from year to year; Miller's measure was constant over the period of analysis.

In addition to pointing out these differences, Murphy criticized several aspects of the fundamental approach applied by Miller and Stevenson:

- Both used the Handy-Whitman Index for estimating a deflated value of net additions to capital stock. Murphy believed this approach overstates the value of capital stock.

- Both analysts failed to adjust their analyses for occasional changes in billing and accounting procedures that lead to shifting the measurement of inputs or outputs forward or backward.

- Neither analyst adjusted output for external effects such as unusually severe winters or summers.

- Neither analyst attempted to account for the varying composition of transactions included in the purchased power and sales for resale accounts.

- Neither analyst included payroll taxes in estimating the initial price of labor services.

- Both analysts used aggregate employment in the utility rather than operating and maintenance employment. Murphy believed operating and maintenance employment would provide a more accurate indicator of the labor service consumed in producing electricity.

- Murphy argued that using the Wholesale Price Index (WPI) to deflate the residual input, materials and supplies, is not a valid analytic procedure because of the differences in composition of the commodity bundles in the WPI and the residual input account.

Testimony of Rodney E. Stevenson
Before the New Mexico Public Service
Commission, Case No. 1419, Public
Service Company of New Mexico (PNM),
<u>October 23, 1978</u>

Dr. Rodney Stevenson was retained by the staff of the New Mexico Public Service Commission to evaluate the use of cost of service indexing for PNM. As part of his critique, Stevenson reviewed TFP analyses presented by PNM for the period 1968 to 1977 and found these analyses to be fundamentally flawed.* To provide a sound basis for analyzing PNM's productivity, Stevenson undertook his own TFP analysis for PNM. PNM's witness had found that PNM experienced a general decline in productivity from 1970 to 1974, but thereafter began to improve its performance; in contrast, Stevenson's analysis indicated that PNM experienced generally deteriorating productivity for the entire period 1969 to 1977.

Stevenson's analysis of PNM's productivity used an analytic approach that differs in several respects from the approach he had applied in his 1976 analysis of ConEd's productivity. The specific conventions used by Stevenson in his analysis of PNM's productivity are:

- Stevenson used a Divisia weighting system for constructing measures of input and output. The Divisia weighting system differs from the Laspeyres weighting system in that the Divisia system allows the relative prices of factor inputs to vary over the period of analysis; thus, it is a less restrictive and more realistic procedure for aggregating over different factor inputs or outputs.

- Stevenson differentiated among different classes of customer service in constructing an output index; in the ConEd analysis, Stevenson did not differentiate among different classes of service.

- Stevenson used five factor inputs in his analysis: capital, fuel, labor, purchased power, and a residual (i.e., other materials and supplies not included in the other input categories). Stevenson then performed sensitivity analyses in which he excluded purchased power and the residual input from the input measure.

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* For example, the PNM witness misinterpreted the TFP index numbers that he had calculated, using first differences to measure year-to-year changes in productivity rather than recognizing that the TFP index numbers indicated the rate of productivity change from the previous year.

- In measuring the labor input, Stevenson included pensions and benefits as part of the cost of labor services and restricted the measurement of labor services to operating and maintenance labor. Both of these treatments differ from the procedure Stevenson employed in his analysis for ConEd in 1976.

- Stevenson restricted the purchased power input to be non-negative. The need to consider this restriction points up one of the problems in using data from FERC's annual publication, Statistics of Privately Owned Electric Utilities, as a basis for the measurement of the purchased power input. In particular, purchased power, as reported in Account 551 of FERC Form-1, includes purchased power and net interchange adjustments. If the net interchange adjustment is large and negative, the purchased power input may have a negative value. In general, the inclusion of net interchanges in the purchased power account confuses the interpretation of purchased power as a meaningful measure of a factor input.

- Stevenson used the same method for estimating capital stock as he employed in his analysis of ConEd. However, in estimating the flow of service from the deflated capital stock, he diverged from his previous analytic procedure by adjusting for the rate of utilization of the capital stock. This divergence probably represents an improvement in his methodology.

As in the ConEd analysis, Stevenson did not attempt to control for factors that are beyond the control of management and that might lead to spurious results regarding the change in a utility's productivity. Stevenson did point out in his testimony that the level of output, in any time period, is not purely beyond the influence of management. For example, through the use of load management and conservation programs, utility management may be able to influence the required level of production in a given time period.

"Comparative Measures of Total Factor Productivity Measures in the Regulated Sector: The Electric Utility Industry," Thomas G. Cowing, Rodney E. Stevenson, and Jeffrey Small, in Productivity Measurement in Regulated Industries, New York, Academic Press, 1981

Drs. Cowing, Stevenson, and Small undertook a comprehensive analysis of alternative approaches to measuring productivity in the electric utility industry using a sample of 81 electric utility firms over the period 1964 to 1975. Their study explained the theoretical bases for the alternative approaches to measuring productivity and summarized the empirical results with regard to the productivity performance of the 81 utilities. The major finding of this analysis is that the relative productivity performance of a utility, as indicated by its rank relative to other utilities, may vary moderately depending upon the specific formulation of the TFP approach. Their finding suggests that it may be difficult to use TFP analysis as a means of comparatively evaluating the productivity performance of utilities in a regulatory proceeding.

Cowing, et al. specified and tested nine analytic formulations for measuring productivity:

1. Laspeyres weighted TFP
2. Laspeyres weighted TFP adjusted for capacity utilization
3. Laspeyres weighted TFP adjusted for returns to scale
4. Laspeyres weighted TFP adjusted for capacity utilization and returns to scale
5. Divisia weighted TFP
6. Divisia weighted TFP adjusted for capacity utilization
7. Divisia weighted TFP adjusted for returns to scale
8. Divisia weighted TFP adjusted for capacity utilization and returns to scale
9. Cost function-based TFP for capacity utilization and returns to scale.

Laspeyres weighted TFP involves using base period prices for aggregating disparate inputs or outputs in subsequent time periods. The process implicitly assumes that the relative prices of the different components of either input or output are constant over time. Divisia weighted TFP is a less restrictive procedure that accounts for the variation in the relative prices over time of factor inputs or product outputs. In addition, the implicit underlying production function in the Divisia procedure (the transcendental logarithmic function) is considerably less restrictive than the function implied by the Laspeyres process (a linear homogeneous function with perfect substitutability among inputs).

The third general approach, cost function-based TFP, relies on the theoretical finding that, given an assumption of cost minimization, a unique cost function will exist that is mathematically linked to the firm's production function. This concept is known as duality; the principle providing for the concept is the duality theorem.

Using the duality theorem, Cowing, et al. postulated the existence of a unique cost function for a utility and measured productivity by first econometrically estimating a cost function for each utility for the year 1964. The functional form estimated was the transcendental logarithmic function, which is mathematically consistent with Divisia weighted TFP analysis. Second, given an actual level of output and information on input prices, they estimated the production cost that would be associated with that level of output. The utility's productivity was then measured by comparing the actual production cost with the econometrically predicted production cost. When actual cost is less than predicted cost, it presumably indicates that a utility is achieving higher productivity than the average body of utilities, as reflected in the econometrically estimated cost function.

In addition to these three basic approaches to measuring TFP, Cowing, et al. applied special analytic procedures to control for varying rates of capacity utilization and different degrees of the use of economies of scale. These measures were applied because the failure to account for different rates of capacity utilization may result in an over- or understatement of the value of input provided by capital in a given time period. Also, the failure to account for the differential use of economies of scale may result in inaccurately attributing changes in productivity to managerial performance when, in fact, these changes resulted from using economies to scale as a firm expands its production plant. As the source of data for their analysis, Cowing, et al. used the FERC publications, Statistics of Privately Owned Electric Utilities in the United States and Performance Profiles: 1963-70, and a publication by the National Association of Regulatory Utility Commissioners, The Measurement of Electric Utility Efficiency.

Aside from the alternative analytic approaches outlined above, the specific analytic procedures applied by Cowing, et al. followed the common conventions of the TFP analysis. For example, deflated capital stock in a year was estimated by accumulating the annual deflated net additions to capital stock through that year. The factor inputs used in the analysis were labor, capital and fuel, and output; this third factor was measured simply as the net energy generated by a company in a year. That is, the analysis did not differentiate output by class of customer service.

Using each of the different analytic formulations, Cowing, et al. computed TFP indexes for each of the 81 utilities over the period 1964 to 1975. For each of the firms analyzed, Cowing, et al. then computed the average annual TFP index value for the period of analysis. The TFP index value is the ratio of TFP measured in one year to TFP measured in a base year; index values greater than one imply productivity improvement, values less than one imply deterioration, and values equal to one imply no change.

In reporting the results of their analysis, Cowing, et al. focused on the stability of a firm's relative productivity performance (as indicated by the rank of its average annual TFP index value relative to the values for other firms) in and across the different approaches to analyzing TFP. Their findings indicate that selective performance, measured over the different approaches, is moderately stable. For example, Cowing, et al. computed rank correlation coefficients for different combinations of the analytic formulations. Comparing Divisia and Laspeyres weighted measures for the same adjustment, they calculated rank correlation coefficients ranging from 0.78 to 0.88. Comparisons between different adjustments for the same weighting procedure yielded rank correlation coefficients from 0.559 to 1.975. In comparing the ranks for different adjustments, the highest coefficients were for the pair with comparisons of the unadjusted measures to the measures adjusted for returns to scale, suggesting that there is little difference across firms in access to economies of scale. A weaker correspondence was found in comparing the ranks indicated by unadjusted measures with the ranks for measures adjusted for capacity utilization, suggesting that variations in capacity utilization may be an important determinant of apparent performance in measuring productivity.

In comparing the conventionally computed TFP results with the cost-function results, Cowing, et al. found a weaker correspondence than in the comparisons of results within the different specific conventional TFP formulations.

Overall, these findings suggest that analytic results regarding the relative productivity performance of a utility could differ considerably, depending upon the specification of the analytic approach for measuring TFP. While there may be some theoretical justification for choosing one approach over the others, there is little assurance that utilities or regulators will accept the results of a specific approach as a basis for incentive regulation when the results of another approach might materially alter the rates allowed to a utility.

APPENDIX D

COMPARING AGGREGATE COST AND TOTAL FACTOR PRODUCTIVITY INDEXES

As part of our assessment of alternative procedures for measuring and evaluating a firm's performance as a basis for an incentive regulation program, we comparatively analyzed three performance indexes; one was based on total factor productivity (TFP) and two were based on aggregate unit costs. The results of this analysis assisted in confirming our judgment that a TFP-based performance measure would be inferior to an aggregate cost measure in measuring and evaluating a firm's performance. Specifically, because a TFP analysis provides information only on the dynamic performance of a firm, its index measure did not provide results on relative firm performance that were comparable to and consistent with the results based on the aggregate cost measures, which provide information on both the static and dynamic performance of a firm. Indeed, when comparing the rankings of firm performance indicated by the TFP- and aggregate cost-based measures, we found essentially no statistical relationship between the TFP index and either of the indexes based on the aggregate cost measures. In the remainder of this appendix, we describe our analytic procedures and summarize the results.

DEFINING THE INDEXES

Performance indexes were computed and compared for a sample of 25 firms for the period 1969 through 1975. The three performance indexes were defined as follows:

1. <u>A TFP index based on an analysis of total factor productivity in the electric utility industry</u>. This index is a divisia-weighted index with an adjustment

for capacity utilization. The TFP index values* indicate the year-to-year change in the production efficiency of the firm. Four inputs were included in the TFP measure: capital, labor, fuel, and a residual (the residual category was defined as total operating and maintenance expenses minus labor and fuel expenses). (See Appendixes B and C for a detailed discussion of the development of TFP measures)

2. An aggregate unit cost index based on average revenues from the sale of electricity. This index combines comparative evaluations of a firm's dynamic and static performance relative to the performances of 24 other firms. It was computed as follows.** First, average annual revenues per kWh (AAR) were computed by dividing a firm's total revenues from its sales of electricity (i.e., retail sales plus sales for resale) by the sum of its total kWh sales (from retail sales plus sales for resale) and kWh losses.

Second, for each year, 1968 through 1975, we computed a five-year average annual revenue per kWh (FYAR) using a declining weight series for combining the annual values for the "current" year and the four previous years. The declining weight series places greater importance on the more recent years in the five-year average. In computing this index, FYAR is the basic measure of static performance. The method for computing the five-year average annual revenue value in time period T is:

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* These TFP index values were obtained from Dr. Rodney Stevenson of the University of Wisconsin and were developed in a study of alternative procedures for analyzing productivity in the electric utility industry. This study is summarized in Appendix C. For a detailed description of the TFP methodology, see: Cowing, Thomas G., Stevenson, Rodney E., and Small, Jeffrey. "Comparative Measures of Total Factor Productivity in the Regulated Sector: The Electric Utility Industry." Productivity Measurement in Regulated Industries. New York: Academic Press, 1981.

** The indexing procedure described for average revenue performance is identical to the index described in Chapter 4 as part of our recommended comprehensive incentive regulation program.

$$FYAR_T = \sum_{t=T-4}^{T} (AAR_t \cdot W_t) ,$$

$$\text{where } W_t = \frac{e^{(-0.1)(T-t)}}{\sum_{i=0}^{4} e^{(-0.1)i}}$$

Third, for each year 1969 through 1975, we computed the fractional change in average revenues for the most recent year relative to the average value for the preceding five years. In the index, this value (DELAR) is the basic measure of a firm's dynamic performance. The method for computing DELAR is:

$$DELAR_T = \frac{AAR_T}{FYAR_{T-1}} - 1 .$$

Fourth, in order to develop indexes of a firm's performance relative to that of other firms, we used a cardinal-scaling technique to transform the static and dynamic measures of individual firm performance into index values. The scale employed for these index values ranged from -1 to +1. Specifically, for the values of $FYAR_{T,j}$, in a single year T (j=1, ..., 25 firms), we assigned an index value ($IVFYAR_{T,j}$) of +1 to the minimum (i.e., best) value of $FYAR_{T,j}$. In addition, we computed the arithmetic average for the 25 values of $FYAR_{T,j}$ and assigned the arithmetic average ($\overline{FYAR_T}$) an index value of zero (0). For each value of $FYAR_{T,j}$ that is greater than $\overline{FYAR_T}$, we assigned an index value between -1 and 0 by using the following linear ratio scaling formula:

$$IVFYAR_{T,j} = \frac{\overline{FYAR_T} - FYAR_{T,j}}{FYAR_{T,max} - \overline{FYAR_T}} .$$

For each value $FYAR_{T,j}$ that is less than $\overline{FYAR_T}$, we assigned an index value between 0 and 1 by using the following formula:

$$IVFYAR_{T,j} = \frac{\overline{FYAR_T} - FYAR_{T,j}}{\overline{FYAR_T} - FYAR_{T,min}} .$$

The values of $IVFYAR_{T,j}$ are the indicators of a firm's relative static performance when compared with the average of the 25 firms. A value of zero indicates average performance; positive index values indicate better than average performance (i.e., lower than average rates); and negative values indicate worse than average performance (i.e., higher than average rates).

To compute an index of a firm's dynamic performance relative to that of other firms ($IVDELAR_{T,j}$), we followed the same procedure as that described for $IVFYAR_{T,j}$, using the values of $DELAR_{T,j}$ instead of $FYAR_{T,j}$. As a result we constructed an index in which average performance is assigned an index value of zero; better than average performance (i.e., a lower than average rate of increase in rates) is assigned a value between 0 and 1; and worse than average performance (i.e., a higher than average rate of increase in rates) is assigned a value between -1 and 0. The firm with the best performance record in each year (i.e., the lowest rate of increase) is assigned a value of +1; the firm with the worst performance record in each year (i.e., the highest rate of increase) is assigned a value of -1.

Fifth, after the indexes of relative static and dynamic performance were developed, it was necessary to combine these performance index values into a single index. To do this, we adopted the non-uniform weighting procedure described in Chapter 4. Specifically, the weighting procedure assigns a higher weight to static performance for those firms with relatively better static performance; correspondingly, these firms' dynamic performance is deemphasized by assigning a lower weight on dynamic performance. On the other side of the scale, firms with relatively worse static performance have a lower weight assigned to this measure and a higher weight assigned to dynamic performance. A firm with average static performance will have uniform weights assigned in combining the indexes of static and dynamic performance.

This variable weighting scheme was adopted to recognize that firms with superior relative static performance may experience difficulty in achieving good dynamic performance; yet, in an incentive program, we would want to encourage and reward the achievement and maintenance of relatively better static performance. Thus, for these firms, the weighting scheme emphasizes static performance and deemphasizes dynamic performance. Conversely, firms with relatively poor static performance may have difficulty, at least for some period of time, in achieving good static performance; however, in an incentive regulation program, we also want to encourage and reward the achievement of relatively better dynamic performance. Therefore, the weighting scheme for these firms emphasizes dynamic performance and deemphasizes static performance. Of course, the relative degree of emphasis of these two types of performance should shift smoothly as the firm achieves different levels of relative static performance.

With these points in mind, our weighting scheme is as follows. The firm with the best static performance (i.e., $IVFYAR_{T,j} = 1$) receives a weight of 2/3 on static performance and 1/3 (or 1 minus 2/3) on dynamic performance. The firm with the worst static performance (i.e., $IVFYAR_{T,j} = -1$) receives a weight of 1/3 on static performance and 2/3 (or 1 minus 1/3) on dynamic performance. A firm that had attained an average level of static performance (i.e., $IVFYAR_{T,j} = 0$) would receive uniform weights (1/2 on dynamic performance and 1/2 on static performance).

For static performance index values between - and +1, the weights are assigned on a linear interpolative basis. Accordingly, the formula for the static weight is:

$$WT_{IVFYAR} = 1/2 + \frac{IVFYAR}{6}$$

for the dynamic weight, it is:

$$WT_{IVDELAR} = 1 - WT_{IVFYAR} .$$

Using the weights calculated for each firm in each year, we summed the index values for static performance (IVFYAR) and dynamic performance (IVDELAR) in each year to develop a composite index of a firm's relative static and dynamic performance with respect to its revenues per kWh. We then multiplied the composite mix values by 100 to give the scale a general range of -100 to +100.

3. An aggregate unit cost index based on gross revenues from the sale of electricity minus returns to capital. The basic measure of aggregate cost embodied in this index is defined as a ratio whose numerator is equal to the sum of the following accounts:

- Total electric operating and maintenance expense,
- Depreciation expense,
- Amortization expense, and
- Taxes other than income taxes.

This numerator is equivalent to gross revenues from the sale of electricity less interest expense, after-tax earnings, and income taxes. The denominator is the sum of the firm's total kWh sales (from retail sales plus sales for resale) and kWh losses. As described for the average revenue index, we developed an index scoring and weighting procedure for combining the measures of a firm's static and dynamic performance relative to those of other firms. In all respects, except for substituting the revised definition of average cost per kWh in the numerator, we used the same method for developing this index as that described for the average revenue index.

ANALYZING PERFORMANCE AS INDICATED BY THE INDEXES

To analyze the performance indicated by these indexes, we used them to compute the index values for a sample of 25 firms over the period 1969 through 1975. As we previously indicated, the TFP values were obtained from Dr. Rodney Stevenson. We computed the two aggregate cost indexes using data from the 1964-1975 annual volumes of the Federal Power Commission's publication, Statistics of Privately-Owned Electric Utilities in the United States.

To analyze the comparability and similarity of these alternative indexes in indicating a firm's performance, we ranked the 25 firms' performance as indicated by the indexes for each year. Thus, for each firm in each year, we obtained three performance ranks, one for each index. Exhibits D.1, D.2, and D.3 illustrate the index scores and ranks for the three indexes.

Exhibit D.1

TOTAL FACTOR PRODUCTIVITY INDEX VALUES (PI) AND RANK ORDERING (PIR)

	ANNUAL PERCENT CHANGE IN TOTAL FACTOR PRODUCTIVITY (PI)							PRODUCTIVITY INDEX RANK ORDER (PIR)						
UTILITY	1969	1970	1971	1972	1973	1974	1975	1969	1970	1971	1972	1973	1974	1975
1	5.29	5.00	-1.14	-11.19	-3.04	-1.90	-3.55	4	4	20	25	22	19	25
2	1.95	1.53	-0.90	1.20	-5.49	0.33	-3.25	8	9	17	12	23	12	21
3	5.78	-0.16	-0.40	2.12	-2.63	4.27	4.96	3	18	16	10	21	4	4
4	-1.35	4.86	-1.13	-4.04	4.30	-1.12	-0.56	22	5	19	24	7	16	18
5	0.36	0.13	2.15	2.57	0.37	1.86	1.35	16	17	11	8	15	7	9
6	1.28	1.16	-0.02	2.40	3.11	0.50	1.96	9	12	14	9	9	11	8
7	1.21	0.38	-0.05	-2.22	2.82	1.66	-2.91	10	16	15	22	11	8	20
8	0.13	3.99	-0.96	-1.86	5.06	0.72	2.90	18	6	18	21	5	10	7
9	-3.48	10.66	0.15	15.25	-0.49	3.37	18.98	25	1	13	1	18	6	1
10	15.04	-2.37	7.23	-3.04	-10.70	10.86	-2.54	1	24	5	23	24	2	19
11	4.18	1.65	-10.32	14.68	1.36	5.44	0.95	5	8	25	2	13	3	11
12	-1.45	-0.62	-3.11	7.32	2.92	-13.23	9.23	23	20	21	3	10	23	2
13	-0.43	-1.21	-4.09	-1.85	4.74	-1.56	-3.51	20	21	23	20	6	18	24
14	-0.38	0.51	-3.27	2.59	-29.72	53.97	-3.39	19	14	22	7	25	1	22
15	0.72	2.35	-6.32	4.71	1.63	-2.25	0.60	11	7	24	5	12	20	13
16	0.49	8.46	3.92	4.37	39.05	-26.72	0.67	14	2	[illegible]	6	1	25	12
17	3.17	1.34	7.50	0.49	-0.34	-9.18	-0.35	6	11	4	15	14	22	17
18	-1.15	1.50	3.96	5.35	-0.68	-2.65	0.24	21	10	8	4	19	21	15
19	0.42	-0.27	7.56	-1.00	-0.46	4.00	7.95	15	19	3	18	17	5	3
20	0.05	5.34	0.53	-0.15	3.41	-1.24	-3.48	17	3	12	17	8	17	23
21	0.68	-1.53	7.07	0.98	-1.22	0.31	3.00	12	22	6	13	20	13	6
22	-1.61	0.81	5.10	-0.11	0.03	-0.29	1.28	24	13	7	16	16	14	10
23	7.32	-1.89	8.25	0.92	6.34	0.80	0.19	2	23	2	14	4	9	16
24	0.57	0.49	3.90	1.37	[illegible]7.08	-20.64	4.80	13	15	10	11	2	24	5
25	1.99	-5.48	10.50	-1.59	[illegible].39	-0.30	0.32	7	25	1	19	3	15	14

Exhibit D.2

REVENUE INDEX VALUES (RI) AND RANK ORDERING (RIR)

	REVENUE INDEX VALUES (RI)					(SEE NOTE BELOW)		REVENUE INDEX RANK ORDER (RIR)						
UTILITY	1969	1970	1971	1972	1973	1974	1975	1969	1970	1971	1972	1973	1974	1975
1	-21.18	-2.18	14.40	15.06	-10.35	7.15	-13.69	22	18	12	14	16	16	17
2	-23.56	7.85	19.37	12.10	-4.90	33.08	30.58	23	15	10	16	14	6	8
3	-15.45	39.87	34.53	39.39	4.78	-64.05	-48.33	19	3	4	4	12	23	25
4	27.26	-19.52	-8.15	-31.39	-30.96	10.51	-20.50*	6	20	18	22	22	13	18
5	-4.45	18.83	-17.55	-7.01	-18.23	-64.57	-26.73	14	10	21	19	17	24	20
6	-26.96	8.22	-9.60	-0.73	-31.71	7.54	-47.77	24	19	19	17	23	15	24
7	-49.25	-64.53	19.86	25.75	-6.66	13.88	-0.86	25	25	9	8	15	12	15
8	-14.38	7.02	12.98	15.14	1.51	32.82	34.57	18	16	13	13	13	7	7
9	-20.41	-27.30	-47.18	-37.72	33.33	29.13	6.95	21	22	24	24	4	8	12
10	17.02	11.81	6.23	20.83	31.23	16.58	56.32	8	13	16	10	5	10	5
11	38.24	75.12	87.02	82.68	59.49	16.68	3.27	4	1	1	1	2	9	14
12	-11.70	-37.11	-11.78	-10.59	-28.16	-21.17	-25.90	17	24	20	20	21	21	19
13	2.81	23.32	20.08	27.60	31.14	45.16	57.80	11	6	8	7	7	5	4
14	42.05	9.59	6.22	-3.27	-21.77	6.18	19.34	3	14	17	18	19	17	10
15	-11.57	36.86	21.64	21.02	-23.70	-48.66	-46.46	16	4	7	9	20	22	23
16	64.24	20.24	15.46	32.71	15.05	46.41	86.58	2	8	11	6	10	4	1
17	-3.80	17.23	52.26	56.79	29.23	63.46	73.35	13	11	3	2	8	2	3
18	24.27	29.22	23.79	20.07	31.15	9.97	27.12	5	5	6	11	6	14	9
19	-18.39	-36.00	-66.24	-73.19	-76.50	-72.08	-38.52	20	23	25	25	25	25	22
20	13.26	14.23	8.15	14.37	17.35	5.44	4.35	9	12	15	15	9	18	13
21	23.96	19.00	11.45	17.34	10.59	-12.00	-9.21	7	9	14	12	11	19	16
22	65.83	65.69	55.90	55.92	63.13	59.61	52.12	1	2	2	3	1	3	6
23	4.46	22.62	28.37	33.26	46.42	72.95	77.11	10	7	5	5	3	1	2
24	2.02	-13.35	-31.55	-23.90	-20.00	-19.71	-29.41	12	19	23	21	18	20	21
25	-9.68	-21.36	-22.30	-37.26	-43.35	15.88	19.06	15	21	22	23	24	11	11

NOTE INDEX =((STATIC INDEX X SW) + (DYNAMIC INDEX X DW(I E 1 - SW))) X 100

Exhibit D.3

COST INDEX VALUES (CI) AND RANK ORDERING (CIR)

	COST INDEX VALUES (CI)					(SEE NOTE BELOW)		COST INDEX RANK ORDER (CIR)						
UTILITY	1969	1970	1971	1972	1973	1974	1975	1969	1970	1971	1972	1973	1974	1975
1	-58.62	-14.05	6.89	2.28	-0.30	24.35	26.63	24	17	9	15	18	19	14
2	55.47	71.64	87.02	2.21	-1.54	33.33	33.33	1	1	1	16	19	13	12
3	24.23	8.59	24.61	33.61	0.53	-33.32	-10.43	5	7	8	8	16	25	25
4	30.83	-8.49	-15.09	-8.89	2.36	25.49	26.38	4	14	16	20	15	18	16
5	-8.21	-12.95	-62.16	-16.98	-15.54	-16.09	18.63	13	16	24	23	23	22	21
6	-0.87	-7.40	-10.35	3.69	-4.46	32.85	-8.88	10	12	13	14	21	15	24
7	-0.97	11.98	30.44	33.33	28.69	48.03	23.40	11	5	6	9	12	9	17
8	-27.19	1.29	4.00	1.21	32.52	59.18	65.41	15	9	10	18	11	6	5
9	-42.08	-35.83	-19.32	1.44	48.16	51.10	52.56	22	21	18	17	6	7	7
10	17.23	50.70	45.25	70.05	47.92	49.35	63.48	6	2	3	2	7	8	6
11	14.91	31.54	32.31	69.14	64.61	33.95	21.57	7	4	5	3	3	12	20
12	-65.40	-61.44	-50.30	-27.17	-10.31	-9.58	22.59	25	24	23	24	22	21	18
13	-4.63	-17.80	-2.31	10.78	40.24	65.69	72.84	12	18	11	12	10	4	4
14	50.09	-7.82	-21.27	10.52	0.24	30.24	31.55	2	13	19	13	17	16	13
15	35.73	6.17	-15.24	-8.92	-38.67	-16.28	6.18	3	8	17	21	25	23	23
16	10.87	39.08	47.25	72.99	62.41	91.47	84.07	8	3	2	1	4	1	1
17	-23.59	-6.95	42.89	54.16	42.38	76.89	79.57	14	11	4	5	8	3	2
18	-41.08	-17.96	-7.00	35.92	53.39	39.46	38.97	21	19	12	7	5	10	10
19	-42.34	-68.87	-79.91	-45.50	-38.64	-17.29	15.90	23	25	25	25	24	24	22
20	-39.95	-5.90	-13.31	29.66	41.43	37.82	39.11	20	10	14	10	9	11	9
21	-38.32	-34.43	-24.82	22.99	19.52	21.97	33.42	18	20	20	11	13	20	11
22	-29.00	-12.88	-14.86	56.59	65.77	62.65	26.52	16	15	15	4	2	5	15
23	4.32	10.28	28.79	50.16	72.36	87.60	74.75	9	6	7	6	1	2	3
24	-38.96	-56.82	-35.42	-2.40	16.15	26.71	21.62	19	23	22	19	14	17	19
25	-36.40	-49.38	-34.95	-15.86	-3.10	32.97	45.89	17	22	21	22	20	14	8

NOTE INDEX =((STATIC INDEX X SW) + (DYNAMIC INDEX X DW(I E . 1 - SW))) X 100

To test the stability of the performance rankings from index to index, we computed rank correlation coefficients for each of the three possible pairwise combinations of index rankings. The rank correlation coefficient (often referred to as rho) is a measure of the stability or similarity of the ranks assigned to a set of observations (in this case, firms) on the basis of two sets of scores (here, the performance indexes). A value of +1 indicates a perfect matching of two sets of ranks. A value of -1 indicates the exact opposite matching of two sets of ranks (i.e., a firm receives the highest rank on one scale and the lowest rank on the other with every other firm switching ranks in the same manner). A value of zero indicates no statistical relationship between the two sets of ranks.

On the basis of this rank correlation analysis, we found a relatively high degree of correspondence between the performance ranks for the average revenue and average cost indexes: the average value of rho over the seven years is 0.679. We found essentially no correspondence between the TFP index ranks and both the cost and revenue index ranks. In these cases, the average value of rho over the seven years for the TFP and revenues index ranks is -0.145; the average value of rho over the seven years for the TFP and cost index ranks is 0.018 (see Exhibit D.4). As a result of these findings, we conclude that the TFP index does not measure the same kind of performance as the cost and revenue indexes. In particular, the TFP index considers only the change in absolute production efficiency (i.e., it measures only dynamic performance) while the cost and revenue indexes consider the relative static and dynamic performance of firms. As we argue in Chapter 2, an incentive regulation program should be based on the evaluation of both static and dynamic performance.

Exhibit D.4

SUMMARY OF RANK CORRELATION COEFFICIENTS

RHO = RANK CORRELATION COEFFICIENT (AS PERCENT)
RI = REVENUE INDEX
CI = COST INDEX
PI = TOTAL FACTOR PRODUCTIVITY INDEX

DESCRIPTION	1969	1970	1971	1972	1973	1974	1975	MEAN
RHO (RI.CI)	16.85	38.00	67.46	81.46	89.46	91.62	90.46	67.90
RHO (RI.PI)	-23.08	1.62	-15.85	1.77	-13.77	-8.69	-43.31	-14.47
RHO (CI.PI)	34.08	21.92	-7.00	0.92	12.69	-13.08	-37.00	1.79

APPENDIX E

THE ICC RAIL RATE ADJUSTMENT MECHANISM

In Section 203 of the Staggers Rail Act of 1980 (49 USC 10707a), Congress instructed the Interstate Commerce Commission (ICC) to publish quarterly or more frequently a "rail cost adjustment factor" that would provide a basis for automatic adjustments to railroad rates. In April 1981, the ICC promulgated final rates to implement a quarterly rail rate adjustment mechanism (49 CFR Part 1102).

Because the ICC rail rate adjustment represents a regulatory commission's effort to develop a systematic cost measurement and rate adjustment mechanism, it is reviewed and evaluated here. In the following sections, we describe the ICC rail rate adjustment mechanism, review the major issues raised in the ratemaking proceeding which may be relevant to designing an incentive mechanism for the electric utility industry, and briefly consider a similar rate adjustment procedure for possible use as an incentive mechanism in the electric utility industry.

Description of the ICC Rail Rate Adjustment Mechanism

This mechanism is designed to allow railroads to increase their rates in line with increases in the cost of certain factor inputs without going through a formal, lengthy regulatory proceeding. Each quarter, the ICC sets a ceiling percentage of increase that railroad firms may apply at their discretion in setting rail rates for the upcoming quarter. The firms may then adjust their rates from quarter to quarter by a percentage amount that does not exceed the percentage change in the ICC rail rate adjustment index.

The percentage limit on adjustments applies to rail rates on an individual freight service basis; that is, a rail firm may not increase any specific rate by more than the allowed percentage increase, even though the aggregate increase over all of the firm's rates still falls below the percentage limit. So long as adjustments to individual freight services meet the percentage limit, the revised rates may be put into effect with only one day's notice.

The allowed percentage increase in rail rates is determined by the change in a composite index of the price of factor inputs to railroad operations. Because the ICC did not believe it possible to design and apply a comprehensive cost index within the time period that Congress mandated for implementing an adjustment mechanism, the ICC adopted the readily available Association of American Railroads' (AAR) input price index, which is based on input price information compiled quarterly from AAR member firms. In addition, ICC conducted statistical analyses which verified the reasonableness of using the AAR index.

The AAR index is a Laspeyres (fixed initial input mix) index. The component weights in the index are based on the average mix of factor inputs for all railroads reporting price information to the AAR. ICC plans to update these fractional weights annually to reflect change in the railroads' average mix of factor inputs. The general input categories that comprise the price index are: salaries, wages and supplements; fuel; materials and supplies; and other expenses (e.g., a depreciation allowance). The weights currently applied by ICC to these component categories are based on the mix of factor inputs at 1980 base prices. They are as follows:

Input Category	Weight (Percent)
Salaries, Wages, and Supplements	47.2
Fuel	12.3
Materials and Supplies	12.2
Other Expenses	28.3

In compiling the quarterly index, AAR collects price information on the materials and supplies, and on other expenses categories from 10 railroad firms; it collects fuel price information from all Class I railroads. Wage, salary, and supplement levels are estimated on the basis of escalation rates specified in rail labor contracts. Because the sample of firms reporting non-fuel price information is relatively small, ICC has indicated its concern that the price data may not fully represent all railroads' input prices.

To minimize the earnings attrition associated with regulatory lag, the ICC allows rates to be increased based on the expected increase in input costs to a point midway in the quarter in which the rate adjustment applies. Specifically, using regression analysis, the ICC forecasts the price index as measured midway through one quarter to a point midway in the upcoming quarter. Through this procedure, the ICC intends to approximate the average rate increase that would be allowed if the price index and rates were adjusted monthly.

The ICC does not intend that companies use the rail rate adjustment mechanism to recover the costs of expense items that do not recur on a frequent and routine basis, for example, the cost resulting from major purchases of capital equipment. Instead, it continues to deal with such expenses and the associated adjustments to base rates in company-specific rate proceedings. In addition, if a rail firm can substantiate that the adjustment mechanism is not adequately offsetting the effects of inflation, then the firm may file with the ICC for a rate increase to recover its additional costs. ICC rules for individual firm filings prevent a company from using both the rail rate adjustment mechanism and an individual firm filing to achieve a double recovery of inflation-related increases in cost.

Review of Issues Relevant to the Design of Electric <u>Utility Incentive Mechanisms</u>

During the ICC ratemaking procedure, various intervenors (e.g., rail firms, shippers, and their trade organizations) raised a number of issues concerning the design and implementation of the rail rate adjustment mechanism. Below, we discuss the issues that may be relevant to the design of an incentive mechanism for the electric utility industry.

1. <u>Should the rail rate adjustment mechanism account for differences among firms</u>? The rail cost index is currently based on a mix of factor inputs that are averaged over all of the firms submitting information to AAR. To the extent that the mix of inputs varies among firms and the different components of the index do not experience a uniform rate of inflation, then some firms will have input price increases for the aggregate set of inputs that exceed or fall below the rate of price increase in the composite index. Accordingly, some firms will recover more than their actually experienced price increase of factor inputs, while other firms will recover less. The ICC acknowledged this problem but argued that, overall, the production functions of railroads are sufficiently homogeneous to prevent these wide disparities across firms. In addition, the ICC will permit a firm to appeal for additional rate increases if it can demonstrate that the mechanism's ceiling rate increase is less than the increase the firm needs for the full recovery of its cost increases. However, no provision is made for retracting rate increases under the ceiling formula if they lead to an excess recovery of cost increases.

2. <u>Should the rail rate adjustment mechanism be based on a product cost or an input price index</u>? The rail cost index is an input price index rather than a product cost index. The index assumes that the relationship of physical inputs to the quantity of product does not change; thus, it does not directly account for changes in productivity or cost-reducing changes in the mix of factor inputs. However, various intervenors pointed out that the consistency that with changes in productivity or the mix of inputs, the change in the index of input prices will differ from the change in production costs. Thus, the intervenors argued that the ICC should adjust the index to account for changes in productivity or changes in the combination of factor inputs. ICC's response was that the authorizing legislation specified that the adjustment mechanism should account only for the effects of inflation on rail firm operations. In addition, the ICC argued that it would be extremely difficult, if not impossible, to account fairly and accurately for productivity changes in the rail industry. More recently, the ICC has reopened this ratemaking proceeding and, among other topics, may consider including a productivity adjustment in the adjustment mechanism.

3. Does the rail rate adjustment mechanism provide sufficient incentives for rail firms to operate efficiently and maximize productivity? Some intervenors (e.g., shippers such as the Western Coal Traffic League) argued that, by eliminating regulatory lag, the adjustment mechanism would remove incentives for efficient rail operations. The ICC and other intervenors responded that the mechanism might actually improve incentives for efficiency because firms that could improve their productivity would experience a lower growth in production costs than their rate of input price increase. Accordingly, firms that improved their productivity would earn an additional return that might otherwise not accrue to the firm in a regulated environment. (This incentive effect is not symmetric since a firm experiencing declines in productivity may apply to the ICC for a rate increase to offset increasing production costs.)

4. Should ICC distribute to ratepayers at least some of the additional return earned by firms with improving productivity? As discussed in the preceding issue, the adjustment mechanism may allow firms with improving productivity to earn an additional return (called an economic rent). Some intervenors argued that some or all of this rent would be excess profits and should be distributed to consumers through rate reductions. ICC acknowledged that, if the rail industry were financially healthy, some of the rent ought to be transferred to consumers. However, ICC argued that rail firms currently earn subnormal profits and that at this point in time, it made no sense to worry over increased earnings flowing to the industry.

Applicability of a Similar Rate Adjustment Procedure to the Electric Utility Industry

On the basis of our review of the ICC rate adjustment mechanism, we believe that it may be possible to use such a procedure as an incentive mechanism in the electric utility industry.* Such a mechanism may prove relatively

* See Chapter 5 for a discussion of an automatic rate adjustment mechanism for the electric utility industry that is conceptually similar to the ICC rail rate adjustment mechanism.

easy to administer and could provide substantial incentives to electric utilities to improve their production efficiency. However, in designing an operationally similar incentive mechanism for the electric utility industry, it is necessary to account for differences in the rail and electric utility industries that may require modifications to the concept underlying the ICC mechanism. In addition, modifications may also be required to account for the different objectives of cost adjustment and incentive programs. Both types of modifications are briefly discussed in the remainder of this section.

A chief concern in applying an ICC-type program as an incentive mechanism in the electric utility industry is that the utility industry is not homogeneous enough to permit using a single set of index weights to represent the mix of factor inputs for all firms. Variations in fuel and generation system mix, and in customer characteristics lead to significant variations in the factor input mix across firms. As a result, in designing a program for the electric utility industry, it will probably be necessary to allow for these differences by using mixes of factor inputs that are specific to each firm. A firm's specified mix of factor inputs might remain fixed for a maximum period of, say, three to five years, or until some rearrangement in inputs occurs that is sufficient to trigger a revision in the input mix. At the same time the input mix is specified, the initial cost level to which adjustments would be made would also be specified.

A second concern is how to determine the rate of increase in cost for the different components of a utility's production inputs. Rather than periodically sampling firms on the costs they have incurred, it may be possible to use regional price indexes for various commodities and services as indicators of the change in utility costs (e.g., a regional labor cost index may be satisfactory for estimating the change in utility labor costs).

A third concern is determining which component(s) of a utility's costs (and correspondingly, rates) for which the automatic adjustment would apply. The automatic adjustment could apply to all costs and, accordingly, the full rate. However, this procedure might present problems in that only the utility's short-run costs vary with changes in the current price of factor inputs (e.g., the costs associated with embedded plant and equipment are not changing with changes in the current prices of factor inputs). As a result, it may be more appropriate to apply the adjustment to only that portion of current rates that is based on non-capital inputs. In this case, the utility would continue to file periodically in regular rate cases for rate adjustments based on changes in its capital costs or cost-of-capital.

A fourth concern is how to control for factors or events that are beyond management's control. Perhaps the most easily implemented procedure would be to outline criteria for events or factors that utility regulators would view as beyond management's control; for example, the Nuclear Regulatory Commission might require that a firm's nuclear generating units be shut down when a manufacturing design flaw is discovered. When situations develop that fall within these criteria, a utility would file with regulators to revise the input mix embodied in its rate adjustment index.

How to manage the distribution of a utility's performance gains or losses between the firm and its ratepayers is a fifth concern. Since the ICC program is essentially designed to improve the financial health of the rail industry, the issue of incentive arrangements for sharing gains and losses was not addressed. In an incentive program for the electric utility industry, however, it would be necessary to achieve some distribution of gains or losses in performance that occur while a firm is operating under the rate adjustment procedure. The most practical method for distributing these gains or losses would be an occasional recalibration of the factor input mix relative to output value to transfer any change in production costs achieved by the firm to ratepayers. In this way, before the recalibration, the firm would retain all of the gains or losses it achieved under the program relative to its base period operating characteristics; after the recalibration, the incremental gains or losses would be received by ratepayers. Alternatively, ratepayers could receive a share of the presumed cost performance improvements by including an assumed rate of productivity improvement in the rate increase formulas. That is, assuming input prices are increasing, rates would rise less than the rate of input price increase.

APPENDIX F

ANALYZING THE REDUCTION IN UTILITY OPERATING EXPENSES REQUIRED TO FUND AN INCENTIVE RATE-OF-RETURN PROGRAM

The design of any incentive program should ensure that consumers will not incur unnecessary losses in either their costs or service reliability because of the program. Indeed, consumers should be expected to benefit from the program. In particular, an incentive program should be designed so that firms are provided with a sufficient incentive to undertake cost-reducing improvements, while ensuring that the participating firms do not receive a reward that exceeds the cost-savings associated with an improvement in their performance.

To assist in understanding the potential effectiveness of an incentive rate-of-return incentive mechanism in meeting these goals, we analyzed the reduction in utility operating expenses required to offset an incremental one percent adjustment to a utility's allowed rate of return. Specifically, for a sample of 10 utilities over a period of six years, we asked the question: by how much would performance have to improve (i.e., the utility's cost decrease) to permit the award of a one percent increase in allowed rate-of-return, while ensuring that ratepayers are at least as well off. In answering this question, the analysis provides insight on the potential effectiveness of an incentive rate-of-return mechanism in meeting these goals, we analyzed the reduction in utility operating expenses required to offset an incremental one percent adjustment to a utility's allowed rate of return. Specifically, for a sample of 10 utilities over a period of six years, we asked the question: by how much would performance have to improve (i.e., the utility's costs decrease) to permit the award of a one percent increase in allowed rate-of-return, while ensuring that ratepayers are at least as well off. In answering this question, the analysis provides insight on the potential effectiveness of an incentive rate-of-return program. In addition, the results of the analysis would assist in developing the numerical parameters of an incentive linking operating cost performance to adjustments to the allowed return. On the basis of this analysis, we found that, for a broadly defined measure of current operating cost (i.e., total revenues less interest expense and before-tax earnings), the sample firms would have to achieve, on average, an approximate 2.5 percent reduction in operating costs to offset an increase of one percent in after-tax allowed return on equity.

If an incentive program were to be applied uniformly to all firms in this sample, then the reward parameters would need to ensure that consumers were not just as well off, on average, across firms. Rather, the reward parameter would have to ensure that consumers were at least as well off for the firm that has the highest reduction in operating costs necessary to offset the incremental adjustment to the allowed return. In this case, the reduction in operating cost required to offset the one percent increase in allowed return would be about four percent, which corresponds to the highest offsetting reduction required over the sample of 10 firms.

In the following sections, we more fully describe the procedure for and results of this analysis. First, we develop a framework for the analysis. Then, we summarize and explain the results of the analysis, including the implications for the design of an incentive program.

ANALYTIC FRAMEWORK

To analyze the reduction in operating expenses required to offset an incremental one percent adjustment to the allowed return, it is helpful to posit a simple, hypothetical framework for an incentive program. In this program, average unit cost, excluding return to capital and income tax, is selected as a performance measure. Performance is evaluated by comparing a firm's actual performance to its expected performance level in the absence of the program. If the firm's actual performance is better than its projected performance (i.e., its costs are lower), then it will receive a higher than "normal" allowed return on equity. Inferior performance will lead to a lower then "normal" return.

To analyze this scheme from the customers' perspective, it is necessary to develop some simple relationships. In doing so, we employed the following notation:

RREX: required revenue (excluding return on capital)

F: fuel

O&M: operating and maintenance expenses (excluding fuel)

DEP: depreciation expense

OTX: taxes other than income tax

PP: purchased power

RR: required revenue (including return on capital)

i: interest rate on debt

D: debt capital employed

k: allowed return on equity capital

E: equity capital employed

t: marginal income tax rate.

The required revenue, excluding return on capital, can be expressed as the sum of various operating costs:

$$(1)\quad RREX = F + PP + O\&M + DEP + OTX.$$

For the purposes of exposition, we let ERREX equal the expected value of RREX in the absence of the incentive program, and indicated operating costs under the program as a fractional adjustment to ERREX. As a result, the overall required revenues (RR), with and without the incentive system, will be:*

$$(2)\quad RR_{w/o} = ERREX + iD + k_N\left(\frac{1}{1-t}\right)E.$$

* The incentive return on equity allowed in a time period is assumed to be coincident with the performance to which it is related.

$$(3) \quad RR_{with} = (1-x)ERREX + iD + k_x(\frac{1}{1-t})E.$$

where x is the fractional change in performance under the incentive, k_N is the normal allowed return on equity, and k_x is the allowed return on equity associated with the performance change of x.* The differential in required revenue is simply:

$$(4) \quad RR_{with} - RR_{w/o} = (k_x - k_N)(\frac{1}{1-t})E - xERREX.$$

Under this incentive system, customers are better off (i.e., the utility has lower required revenues) if this difference is negative, that is:

$$(5) \quad (k_x - k_N(\frac{1}{1-t})E - xERREX < 0$$

or if

$$(6) \quad x > \frac{(k_x - k_N)(\frac{1}{1-t})E}{ERREX}.$$

That is, if we assume, on an expected value basis, that x is positive, then the cost reduction generated by the incentive scheme must exceed a specified amount or customers will pay higher, rather than lower, rates. That amount depends on the degree of incentive of the reward/penalty function ($k_x - k_N$), the amount of equity receiving the reward/penalty, the income tax rate, and the expected level of operating costs on which the improvement is to be obtained (ERREX).

Results of Analysis

To understand the required improvement, x, to offset the incremental adjustment to the allowed return, we examined the components of the critical relationship (equation 6) for the 10 utilities, both in terms of their wholesale (i.e., FERC jurisdictional) and total electric revenues. In particular, we calculated the ratio $(\frac{1}{1-t})E/RREX$ for

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* Assumes the interest rate and capital structure are independent of k.

various definitions of RREX from data assembled by the Office of Electric Power Regulation at the FERC. These data were collected in rate cases of the sample utilities before the Commission over the past six years. A range of definitions for RREX was employed to reflect the extent to which certain costs are perceived as "controllable" or "uncontrollable"; the costs excluded from the definition were assumed to be independent of the incentive rate of return and, like the debt cost in the equations above, do not appear in the critical equation.

Summary results of our analysis are found in Exhibit F.1. A simple interpretation is obtained if we set $(k_X - k_N)$ in equation (6) equal to one percent. Then, the entries in Exhibit F.1 are the percentage of cost reduction, for each of the definitions of cost, that would be necessary to offset a one percent increase in the rate of return on equity (after tax).

Five definitions of controllable costs were employed, which range from broad to narrow. Using Utah Power and Light Company (Docket ER82-211, test year ending 12/31/82) as an example, the following definitions were employed:

CONTROLLABLE COST DEFINITIONS

	($ in thousands)	
	Total Sales	Sales for Resale
1. Total Operating Expense Excluding Income Taxes (F + PP + O&M + Dep + OTX)	$577,538	$58,809
2. Cost #1 less Other Taxes (F + PP + O&M + Dep)	544,779	56,083
3. Cost #2 less Depreciation Expenses (F + PP + O&M)	491,351	51,735
4. Cost #3 less Purchased Power (F + O&M)	415,022	42,661
5. Cost #4 less Fuel Expenses (O&M)	197,990	14,108

Exhibit F.1

PERCENT COST REDUCTION NECESSARY TO OFFSET A ONE PERCENTAGE POINT INCREASE IN ALLOWED RETURN ON EQUITY (DOCKET NO. IN PARENTHESES)

	1977		1978		1979		1980		1981		1982	
Company & Cost Category	Total	Resale	Total	Resale	Total	Resale	Total	Resale	Total	Resale	Total	Resale
* Alabama Power												
Company	(ER78-77)								(ER81-95)		(ER82-229)	
1	2.10	2.11							1.99	1.99	1.58	1.48
2	2.30	2.18							2.18	2.06	1.72	1.53
3	2.67	2.48							2.62	2.41	2.00	1.74
4	3.28	3.14							2.60	2.39	2.52	2.27
5	8.88	11.75							6.16	7.28	6.83	9.80
Arizona Public												
Service Co.												
1			(ER78-145)		(ER79-126)				(ER81-179)			
2			3.58	2.09	3.31	2.43			2.71	2.46		
3			4.14	2.30	3.82	2.66			3.26	2.68		
4			4.82	2.52	4.56	2.99			3.91	3.08		
5			5.38	2.85	5.38	3.61			4.49	3.58		
.			12.74	10.08	11.98	11.15			11.24	11.17		
Carolina												
Power & Light	(ER77-485)						(ER80-344)		(ER81-538)			
1	3.04	2.95					2.36	2.22	2.24	2.09		
2	3.19	3.05					2.45	2.28	2.32	2.15		
3	3.76	3.58					2.80	2.60	2.66	2.47		
4	3.85	3.68					2.81	2.61	2.67	2.47		
5	10.74	14.71					7.21	8.83	5.90	6.77		
Delmarva												
Power & Light			(ER78-414)				(ER80-363)		(ER81-504)			
1			2.41	2.35			1.72	1.67	2.09	2.34		
2			2.60	2.43			1.78	2.05	2.39	2.43		
3			2.98	2.75			1.99	2.27	2.76	2.78		
4			2.86	2.63			1.81	2.04	1.81	1.72		
5			8.36	11.84			6.69	11.85	7.49	10.94		

Exhibit F.1 (cont.)

PERCENT COST REDUCTION NECESSARY TO OFFSET A ONE PERCENTAGE POINT INCREASE IN ALLOWED RETURN ON EQUITY (DOCKET NO. IN PARENTHESES)

Company & Cost Category			1978		1979		1980		1981		1982	
	Total	Resale	Total	Resale	Total	Resale	Total	Resale	Total	Resale	Total	Resale
Kansas Power & Light			(ER78-001)		(ER79-283)		(ER80-559)					
1			1.96	1.59	2.07	1.83	3.11	2.84				
2			2.09	1.67	2.22	1.94	3.38	3.04				
3			2.35	1.80	2.55	2.15	4.10	3.54				
4			2.60	2.03	2.49	2.10	3.31	2.82				
5			9.95	12.23	9.70	11.87	11.04	12.93				
Pacific Gas & Electric							(ER80-214)		(ER81-679)		(ER82-271)	
1							1.64	1.26	1.42	1.02	1.42	3.88
2							1.70	1.30	1.45	1.03	1.45	3.95
3							1.87	1.37	1.57	1.08	1.57	4.14
4							2.01	1.49	1.73	1.22	1.73	4.14
5							7.77	13.15	6.38	10.07	6.38	38.41
Public Service Co. of New Mexico							(ER80-313)		(ER81-187)		(ER82-001)	
1							2.61	2.34	2.37	2.12	3.02	2.76
2							2.82	2.44	2.54	2.20	3.21	2.85
3							3.27	2.75	2.84	2.41	3.75	3.26
4							3.67	3.18	3.27	2.86	4.05	3.58
5							5.94	6.28	5.87	6.73	7.48	8.14
So. Cal. Edison Co.					(ER79-150)				(ER81-177)		(ER82-427)	
1					1.68	1.33			1.09	0.78	1.38	1.20
2					1.74	1.37			1.11	0.79	1.41	1.22
3					1.92	1.47			1.18	0.82	1.54	1.31
4					2.01	1.55			1.23	0.87	1.78	1.55
5					6.91	8.50			6.44	9.14	5.68	7.58
Utah Power & Light	(ER77-311)				(ER79-121)						(ER82-211)	
1	3.79	3.22			3.69	3.33					2.59	2.28
2	4.17	3.46			4.05	3.59					2.74	2.40
3	4.84	3.89			4.73	4.09					3.05	2.60
4	6.00	5.22			4.95	4.32					3.61	3.15
5	10.91	14.86			10.91	14.52					7.56	9.53
Virginia Electric & Power			(ER78-522)						(ER81-121)		(ER82-423)	
1			1.91	1.73					1.87	1.69	2.17	1.93
2			2.10	1.91					1.94	1.74	2.26	2.00
3			2.45	2.19					2.22	1.95	2.67	2.34
4			2.50	2.24					2.29	2.02	3.08	2.80
5			8.52	12.63					5.55	5.64	6.26	8.17

For Utah Power and Light, for which the composite tax rate is 48.214 percent, E_{total} = \$775,460 and E_{resale} = \$69,633 (both in thousands), the following results apply:

PERCENT COST REDUCTION NECESSARY TO OFFSET A ONE PERCENT INCREASE IN ALLOWED RETURN ON EQUITY

Cost Category	Total	Resale
1	2.59	2.28
2	2.75	2.40
3	3.05	2.60
4	3.61	3.15
5	7.56	9.53

The question is not whether a one percent additional return on equity is an adequate incentive, but rather, how should the performance/reward relationship be structured so as to ensure that customers benefit from its use? From the above table it can be deemed that, if the broadest cost category were chosen to measure the performance of Utah Power and Light, any relationship which allowed less than a one percent increase in the return on equity for each 2.59 (or 2.28) percent decrease in costs over the assumed base level improvement would benefit customers (as well as reward equity).

Turning back to Exhibit F.1, a number of observations can be made:

1. The differences from one filing to the next for a given company or between companies cannot be attributed to differential tax rates; due to normalization, all the tax rates were roughly 50 percent (48 to 52 percent).

2. Generally speaking, there is relatively little difference between cost categories #1 through #4. Since costs are being more narrowly defined as the categories progress, the required reduction increases (except in a few cases in which the company, on net, has negative purchased power).

CATEGORY VALUES FOR TOTAL SALES

Cost Category	Average	Range
#1	2.33	1.09-3.79
#2	2.49	1.11-4.17
#3	2.87	1.18-4.84
#4	3.06	1.23-6.00
#5	7.57	5.55-12.74

The ranges for categories #1 through #4 are remarkably narrow, considering the extreme diversity of the firms in the sample.

3. There is no significant trend exhibited in the overall time series, although the ratios exhibit some tendency to decline over the period. This would be consistent with fuel and labor costs tending to rise faster than the equity base over the period in question, since fuel costs increase with inflation, while labor costs increase only with new construction.

4. The ratios for the wholesale segments are virtually the same or slightly lower than their total business counterparts for the first four cost categories. Almost uniformly, however, the ratio for the narrowest definition of costs (#5) is higher for the wholesale business. This is because fuel expenses are a much larger component of total wholesale costs than they are for total business, and narrowly defined O&M expenses are a larger component of production and transmission costs relative to their share of the rate base than are distribution (and retail administrative) costs.

5. The instability of a given company's ratios through time can reflect fundamental changes in the company over the period. For example, KP&L displayed the following:

RATIO VALUES FOR KP&L

Cost Category	Ratio Value 1978	1979	1980
#1	1.96	2.07	3.11
#4	2.60	2.49	3.31
Rate Base ($ millions)	$404	$584	$734
Purchased Power ($ millions)	$ 14	$ -4	$-35

> The company brought substantial capacity on line over the three-year period and, as a result, went from being a net consumer of purchased power to a net supplier. The broadest cost category ratio (#1) increased substantially, reflecting the increased rate base (which was probably underutilized), while the ratio net of purchased power showed a much less dramatic change.

There are, of course, many factors which would explain the differences for any ratio from one company to the next. They include fuel types and costs, the original capital costs of facilities, the designed labor intensity of facilities, fuel efficiency of production and transmission, the capital structure, and capacity utilization rates. While some of these factors are difficult to quantify, others are readily available (see Exhibit F.2 for some salient statistics). As expected, the relative importance of fuel expense explains much of the observed variability from company to company, as well as within companies. For example, the relatively low (and falling from 1979 through 1981) ratios for cost categories #1 through #4 for Delmarva P&L, PG&E, and So. Cal. Ed. can be attributed to the relatively high (and increasing) cost of fuel (these utilities are heavily dependent on oil). In 1980, fuel expenses (expressed as a percent of total O&M) were 55 percent for Delmarva and 45 percent for the California utilities, while the other seven companies averaged only 30 percent. Equity ratios require a larger percentage change to offset a one percent increase in their return on equity.

Exhibit F.2

SAMPLE SALIENT STATISTICS, 1980

Company	Sales (kWh x 10^9) Total	Sales (kWh x 10^9) Resale	Fuel as % of O&M[a]	O&M as % of Revenues	Average Price per kWh (¢)	Electric Utility Return on Rate Base	Common Equity as Percent of Total Capitalization	Fuel Composition (Percent Oil, Gas, Coal, Nuclear, and Other)
Alabama Power Co.	33.5	3.9	53.8	65.1	4.22	9.76	31.4	NA
Arizona Public Service	11.9	1.9	36.0	50.1	5.10	11.13	43.0	2/10/78/0/10
Carolina P&L	30.3	6.8	60.0	61.2	3.52	7.93	35.9	0/0/69/28/3
Delmarva P&L	7.5	1.3	75.1	68.5	5.86	7.73	36.0	43/0/36/15/6
Kansas P&L	6.9	0.9	77.3	52.2	4.06	9.56	40.7	2/14/84/0/0
Pacific G&E	58.4	1.9	60.3	74.4	5.30	7.71	40.8	47/[c]/0/0/53
P.S.C. of NM	5.4	1.8	42.5	54.0	5.03	11.14	35.2	0/15/77/0/8
So. Cal. Ed.	59.9	5.5	55.0	81.7	6.06	7.97	32.5	28/30/12/1/29
Utah P&L	15.4	4.4	52.0	53.1	3.89	9.63	39.4	2/[c]/90/0/8
VEPCO	39.2	5.2	48.6	65.1	5.18	9.71	33.8	20/0/25/27/28
Total (Average) Sample	268.4	33.6	56.1[b]	62.5[b]	4.82[b]	9.23[b]	37.5[b]	NM
All Class A&B	1,941.4	321.2	54.6	65.6	4.43	NA	NA	NA
Sample as % of All A&B	13.8%	10.5%	NM	NM	NM	NM	NM	NM

NOTE: NM: not meaningful, NA: not available

SOURCE: U.S. DOE, Energy Information Agency. Statistics of Privately Owned Electric Utilities in the United States, 1980 Annual, Classes A and B Companies. Document No. 0044(80), 1981. Value Line, April 3, 1981; June 12, 1981; May 1, 1981 (fuel composition).

[a] O&M corresponds to cost category #3; fuel is sum of steam power fuel and nuclear power fuel; revenues are from sale of electricity.

[b] Simple average.

[c] Oil and gas together reported as oil.

From the above sensitivity exercise, it would seem possible to set up incentive systems that guarantee the consumer is better off if a utility improves its cost performance relative to some target. For example, if the return on equity was permitted to increase 25 basis points for each 100 basis point reduction in the real cost per unit of output in cost category #1, then the customers of each firm in the sample would find their rates relatively lower (since no ratio in Exhibit F.1 for cost category #1 is above 4.0, i.e., 100/25). The extent to which such an incentive framework would result in improved cost performance and, accordingly, rate reductions for consumers, would depend, of course, on the response by utility managers in effecting cost savings within the firm.

APPENDIX G

EXECUTIVE INCENTIVE COMPENSATION PROGRAMS IN THE ELECTRIC UTILITY INDUSTRY

Incentive compensation programs for top managers and executives are widely used in many industries in the United States. These programs essentially link an executive's annual compensation (e.g., base salary, bonus, stock options) to the individual's and/or the company's performance. By directly linking compensation to performance, a well-designed executive incentive compensation program creates incentives for executives to make decisions and take actions that contribute to the achievement of specified corporate, as well as individual, objectives.

Despite their prevalence in many segments of American industry, executive incentive compensation programs are not widely used in the electric utility industry. However, in recent years, various factors have contributed to a greatly heightened interest by utilities in such programs. These factors include an increasing need to:

- Minimize operating costs during a period of rapid inflation,
- Attract and retain highly qualified and skilled managers, and
- Respond to consumer and regulatory complaints about potential operating inefficiencies.

In addition, because incentive compensation programs focus on management by objectives, this interest also probably reflects the growing sophistication of utility managers in adopting new management techniques to deal with a multitude of financial, planning, operating, environmental, and regulatory problems that were not faced by utilities before 1970.

To understand more about executive incentive compensation programs in the electric utility industry, we asked three utilities to supply us with information on their programs. The program with the longest operating history went into effect in 1976; the one with the shortest history went into effect in July 1982. To protect the confidentiality of some of the information supplied to us, we have not identified the names of the companies. Instead, we refer to them in the following sections as Utilities A, B, and C.

These programs have a number of elements in common. For example, the programs implemented by the three utilities cover only a small portion of each utility's employees. Each program links a covered employee's compensation to one or more performance targets, and a participant in these programs may receive a bonus award ranging from 10 percent to 50 percent of his base salary if the performance targets are met.

However, the programs also differ significantly in several important areas. For example, two of the programs focus on corporate-level objectives, as measured by earnings and rates. The third program focuses on a sub-corporate level objective, specifically, power plant performance. Each of the two programs that focus on corporate-level objectives uses different measures of performance. One company measures corporate performance on the basis of return on common equity, and the other uses net income and rates as performance measures.

In the sections below, we describe and discuss each program's focus, performance measurement, administration, and results. In addition, we attempt to highlight the features of each program that reflect how the utility has chosen to deal with some of the issues discussed in Chapters 2 and 3 (e.g., how to structure incentives to promote a cooperative effort among the participants in an incentive plan).

UTILITY A

Utility A is a holding company with eight subsidiary companies that generate and sell electricity in a seven-state area. Two of the subsidiary companies operate hydroelectric generating facilities, and one operates a nuclear power plant. Five subsidiaries have coal-fired generating facilities consisting of 17 plants with 49 generating units, for a total fossil-steam generating capacity of approximately 19,000 megawatts. As will be discussed below, many of these coal-fired generating units are identical across plants; this facilitates the setting of targets for the individual plants in the utility's incentive compensation program. Each of the five subsidiary companies with coal-fired generating facilities is regulated by FERC. Four of the five subsidiaries are also regulated by at least one state regulatory commission (two subsidiaries are regulated by two state commissions).

Program Description

In 1977, Utility A initiated a program to develop an Incentive Compensation Plan (ICP) for its power plant management at the coal-fired facilities. A consulting firm was selected to assist in developing the plan, which was completed and approved for implementation by the utility's corporate management in 1978. Incentive compensation awards to plant management personnel were first administered in 1979.

The principal objective of the Incentive Compensation Plan is to motivate key power plant management personnel to improve the operating efficiency of the generating system and the effectiveness of management programs at the power plant level. To promote this objective, the program provides monetary incentives to power plant management teams who meet or exceed the following established goals:

- Achieving and maintaining desired levels of short- and long-term plant availability,
- Maintaining a satisfactory plant heat rate,
- Maximizing the cost-effectiveness of operating and maintenance expenditures, and
- Improving management practices and techniques.*

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* The Incentive Compensation Plan stresses efficiency at the plant level and does not address broader corporate level issues, such as providing long-run incentives to corporate managers to purchase fuel at the least possible cost or to make capital expenditure decisions that would minimize the long-run cost to power consumers.

Because the efficient operation of a power plant requires close working relationships and coordination among administrative, operations, and maintenance personnel, the entire top management group at a plant participates as a team in the Incentive Compensation Plan.* The Plant Manager, Assistant Plant Manager, Operations Superintendent, Maintenance Superintendent, and Performance Superintendent are jointly responsible for the plant's performance and thus are evaluated as a team. Employees working under these individuals are rewarded for their individual performance via a merit salary program. The merit salary program covers all of Utility A's employees, including plant managers, and is based upon individual performance evaluations. However, these lower-level employees are not included in the Incentive Compensation Plan.

The ICP's four performance measures address both the results achieved and the effectiveness of the management processes applied by the power plant managers. Three of the measures address quantifiable results: total plant availability, total plant heat rate, and operating and maintenance (O&M) costs (less fuel). The fourth measure is a qualitative assessment of management proficiency in key performance areas that are not directly related to the operating characteristics of individual generating units at a plant. These performance measures include plant safety, labor relations, work planning and scheduling, management reporting, coal sampling and analysis, training programs, and stores administration.

Targets for each of these measures are not chosen by rigid adherence to mechanical formulae. Instead, they are chosen on the basis of the plant's historical operating experience, the performance of other plants in the system, information on "unique" circumstances that the plant may expect to face during the forthcoming year, and the subjective judgments of corporate management and the plant managers.

The manner in which targets are chosen can be best illustrated with reference to specific measures. For example, for total plant availability, a target is set for each

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* Currently, central corporate management is excluded from the plan.

of the plants' one to six operating units. Then an overall plant target is set by weighting each individual unit's target by its share of total plant capacity. The individual unit targets are determined with reference to the unit's annual maintenance requirements (this may vary over time depending upon the maintenance schedule for the unit), the five-year historical average of forced outages the unit has incurred, and planned curtailments for the year (which are based on the condition of each unit). These considerations are tempered by the subjective judgments of corporate management, which are based partially on comparisons with identical units installed in other plants.

Targets are chosen for heat rates with reference to the historical performance of the plant. Here again, "unique" circumstances are factored into the target-setting process. For example, the planned loading of each unit is taken into account because it is well-established that the heat rate varies with the loading of a unit. This consideration has proven important during the last year, because the recession that struck hard in many of the subsidiaries' operating territories has reduced their industrial customers' demand for power and hence the loading of many of their units.

In each performance area, targets are set to reward both continual outstanding performance and improvements in performance. For example, absenteeism is judged with reference to average absentee rates over the entire holding company system. Plants that initially show above-average performance (below-average absentee rates) in this area might be given targets that call for them to maintain their performance. In contrast, plants that initially show below-average performance (above-average absentee rates) might be given targets that call for them to move towards the average absentee rate in the system. In several of the other areas, such as work planning, the setting of targets is much more subjective and is determined by "criteria audits."

Because of the size of Utility A's generating system, comparisons with other utilities are not customarily made in setting performance targets. The company feels that it is among the most efficiently run in the industry, and because it has identical generating units operating in a number of plants, such comparisons are unnecessary.

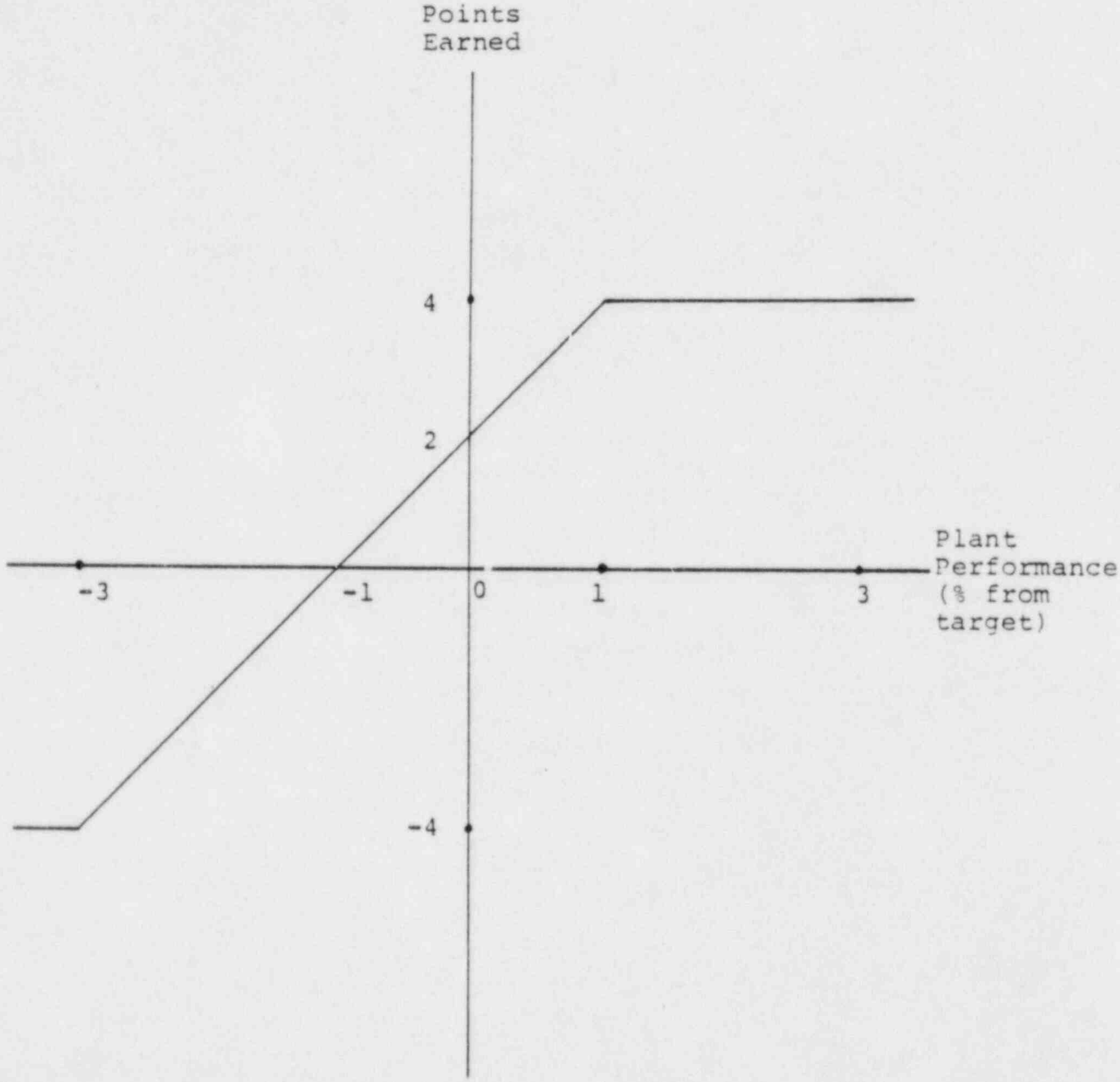
The plan is implemented on a plant-by-plant basis and targets are established annually for the four performance measures. Most incentive compensation plans in the private non-regulated sector are based on multi-year performance to encourage management to take actions that are in the long-run interests of the firm. However, because Utility A's plan is directed at the decisions made by plant management (which are more short-run in nature than those made by corporate management), and because their budget and maintenance plans are drawn up on an annual basis, Utility A chose to tie its incentive compensation plan to annual performance measures.

Incentive points are awarded to each plant's management team based on the team's relative success in meeting the targets established in the four performance areas. A maximum of plus or minus four points can be earned in each of the three quantifiable performance areas. In the management proficiency performance area, the range of incentive points that can be earned is zero to plus four. Thus, the total number of incentive points that a plant can earn in a year can range from plus 16 to minus 12 points.

In each of the three areas where the company can fairly accurately measure the dollar savings due to improved performance (i.e., higher unit availabilities, lower heat rates, and lower O&M costs), the number of points received varies with deviations in actual performance from target performance. For example, meeting the plant availability target yields two incentive points. In addition, plus (minus) one point is given for each one-half percent increase (decrease) in the availability rate as compared to the target rate. That is, if the availability rate achieved exceeds the target by one percent, the plant earns an incentive point score of plus four. On the other hand, if the availability rate is three percent less than the target, the plant earns an incentive point score of minus four. The relationship between plant availability and performance point scores is presented graphically in Exhibit G.1. Points in the heat rate and operating and maintenance cost areas are assigned in an analogous way, with a maximum of plus or minus four points awarded in each area.

Exhibit G.1

PERFORMANCE/POINT SCHEDULE FOR
PLANT AVAILABILITY AREA



In the fourth area, management proficiency, one-third of a point is awarded in each of 12 categories* if the category target is met, and no points are awarded if the target is not met. This leads to a "performance/point" schedule like the one shown in Exhibit G.2. In the management proficiency areas, points do not vary at the margin with performance. That is, unlike incentives provided in the other three areas, no incentive is provided for plant managers to do better than their management proficiency performance targets. Utility A's rationale for this difference is that it is difficult to attain an accurate measurement of the cost-savings in this area at the margin. Because improving performance substantially beyond the targets may result in higher targets in the future (see below), this lack of marginal reward for exceeding the targets may have an adverse effect on a manager's efforts (at the margin) in the management proficiency area.

The total points that each plant receives in the four performance areas are then weighted by a factor that varies with the generating capacity of the plant, according to the schedule shown below.

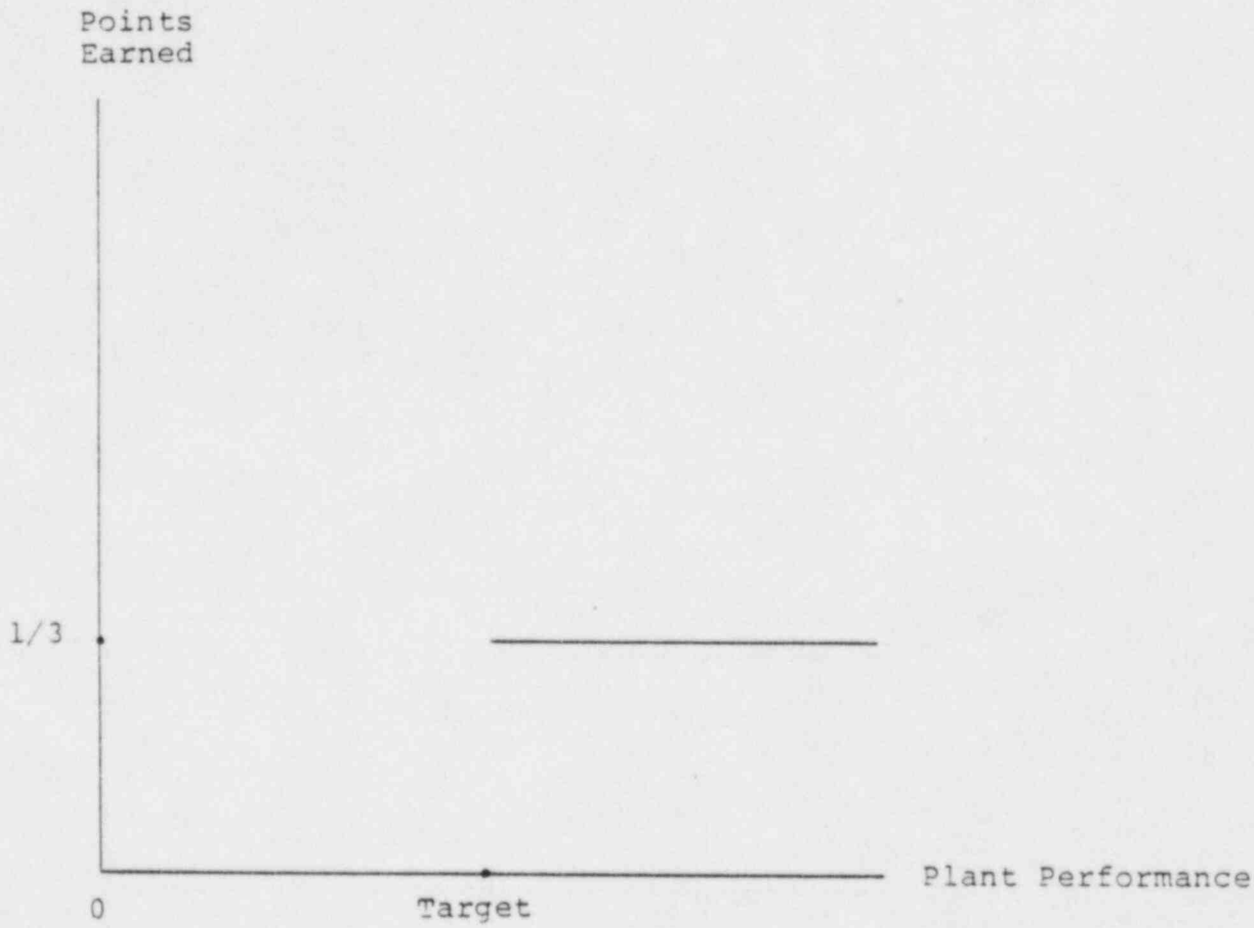
PLANT SIZE WEIGHTS

Plant Size	Weight
1,800 MW and up	1.25
1,000 to 1,799 MW	1.00
300 to 999 MW	.75
Less than 300 MW	.50

* Examples of the 12 categories are: accidents per 200,000 man-hours, average man-days lost per accident, average sick days per person, number of grievances, employee turnover, work planning documentation and effectiveness, completeness of coal sampling/analysis, training programs, storeroom operations, and results from company audit reports.

Exhibit G.2

PERFORMANCE/POINT SCHEDULE FOR
MANAGEMENT PROFICIENCY AREA



The weighted point total for a plant is used to calculate the incentive compensation award for each plant management team. Specifically, a plant's weighted point total is multiplied by the aggregate base salaries of the plant's team members to determine the plant's incentive compensation award. The maximum incentive opportunity varies by plant size from eight percent of the aggregate base salaries for the smallest plants' team up to 20 percent of the aggregate base salaries for the largest plants' team. This weighting scheme was adopted because the magnitude of the dollar benefit to the company varies with plant size.*

There are no explicit penalties assigned under the ICP for poor net performance (negative points), primarily because if unexpected events caused a plant to perform poorly during a year, Utility A would not want to penalize its managers. On the other hand, if a plant persistently failed to meet its targets over longer periods, Utility A probably would replace part or all of that plant's management team. In this sense, the program does have implicit penalties.

Program Administration

As we noted above, Utility A adopted the Incentive Compensation Plan in 1978 and implemented it in 1979. In mid-January 1979, Utility A's coal-fired plant managers were briefed on the plan and provided with a written description of the plan to distribute to the participants at each plant. Source documents and definitions for the three quantifiable measures of availability, heat rate, and operating and maintenance costs were identified at this briefing. The selected source documents were existing management reports that are available on a continuing basis by the 20th of the month for the preceding month, and by January 20 for the preceding year.

A Plan Committee administers the plan by developing annual goals with each plant management team, reviewing

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* That is, a one-percent efficiency improvement in a larger plant results in a greater level of dollar savings than a one-percent efficiency improvement in a smaller plant.

performance, and determining incentive awards. The Plan Committee consists of the Senior Vice President-Operations, the Assistant Vice President-Plant Operations, Manager-Wage and Salary Administration, and the Operating Company Power Plant representatives.

The Plan Committee meets with the manager of each plant during the first week of February each year to set performance targets for the plant for that year. In preparing for this meeting, historic data on each plant's availability, heat rate, operating and maintenance costs, absentee rates, and other performance indicators are tabulated and used as a basis for target-setting. The process is repeated with each plant manager until targets are set for all the plants.

The Plan Commiteee then presents the targets in a meeting with the Chairman and the operating company Presidents. Individual plant targets and benefits of the plants' achieving their targets are discussed, and final targets are approved at this meeting. Each plant manager then reviews the approved targets with the ICP participants at the plant. Utility A tries to ensure that the approved targets are transmitted to the plant managers by March 1.

Each plant manager is asked to submit any requests for target changes to the Plan Committee early in the following December. As soon as year-end performance results are known (usually about January 20 of the next year), the Plan Committee meets to consider the requests for target changes, calculate final performance results to reflect any approved target changes, and determine incentive awards.

The Plan Committee presents the final performance results and proposed award payments during a meeting with the Chairman and the operating company Presidents, who must approve any award payments. Proposals for and decisions concerning improvements and changes in the plan are also made at this meeting. The Plan Committee then meets with each plant manager during the first week of February to review results, present incentive awards, and set targets for the next year.*

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* It should be noted that the administration of the ICP is separate from the administration of performance reviews and salary determinations for individuals that may be covered under the program.

Program Results

During the first three years of the ICP (1979-1981), the average effective system availability of Utility A's fossil units increased from 70.5 percent to 75.4 percent. In 1981 the utility's average system heat rate decreased despite a number of adverse situations, including a coal miners' strike that necessitated the purchase of lower-quality, less effective fuels. In the three-year period, actual O&M expenditures have been within three percent of the approved annual budget for operating and maintenance expenses. In the last two years, O&M expenses have been under the approved, which was approximately $250 million in 1981.

Utility A estimates that the dollar value to the company from performance improvements in 1981 was approximately $25 million. This dollar value reflects fuel savings from meeting or exceeding heat rate targets, actual operating and maintenance cost reductions, and higher revenues made possible by an increase in the kilowatt-hours available for sale, which is attributable to improvements in unit availability. Approximately $295,000 in bonus awards was earned by 70 of the 85 plant supervisors. The estimated administrative cost of the program is $10,000 to $15,000 per year.

Three points should be noted about the 1981 results. First, incentive awards were made to 14 of the 17 plants in 1981. During the three years of the plan's existence, up to 16 of the plants have received awards. However, one plant has not received an award during any year of the ICP's existence, and managerial changes have, or will take place at this plant in the near future.

Second, approximately 1.2 percent of the estimated dollar value of the plan in 1981 ($295,000/$25,000,000) was paid to managers in 1981 under the incentive program. This percentage distribution was not preset. That is, the ICP does not set the potential level of total incentive compensation awards as a percentage of the dollar value of the program in a given year. The only implicit award target in the ICP is the plant weighting scheme that is designed to allow managers at the largest plants to earn up to 20 percent of their aggregate base salaries as a performance award. The average percentage bonus award to date has been approximately eight percent.

Third, although the state public utility commissions that regulate the five subsidiary companies in the ICP have been briefed on the plan, the regulators and companies have not yet discussed what the appropriate distribution of the program's dollar value (i.e., savings) should be between consumers (in the form of lower rates) and managers.

Program Issues

The ICP at Utility A appears to be well-conceived, inexpensive to administer, and relatively successful at creating incentives that result in improved power plant performance. However, four issues should be addressed for incentive compensation programs like Utility A's. First, the program currently operates only at the individual power plant level, stressing short-run, technical efficiency issues. The program does not address broader, long-run issues at the corporate level, such as providing incentives for corporate managers to make capital expenditure decisions to minimize the long-run cost of power to consumers. Such decisions clearly affect the price of delivered energy to purchasers and the availability of adequate capacity levels; the outcomes of such decisions are presumably the ultimate concern of purchasers.

Utility A (and other utilities that adopt similar programs) should thus consider extending the program to the corporate level and focusing on variables, such as delivered electricity prices, that are influenced by both short- and long-run management decisions. Performance at the corporate level of the program might also be evaluated over intervals longer than a year to reflect the results of short- and long-run management decisions. Performance at the corporate level of the program might also be evaluated over intervals longer than a year to reflect the results of short- and long-run operating, planning, and investment decisions.

The second issue that should be carefully addressed in an incentive program similar to Utility A's ICP is how plant performance targets should be set. Under the ICP, targets are set partially with reference to the performance of similar operating units within Utility A's system, but not against those of other utilities. Unless Utility A is certain that its units operate more efficiently than those of other utilities, comparisons with similar generating units operated by other utilities might be warranted. Obviously, such comparisons would more likely be required if a utility that is much smaller than Utility A attempted to implement an incentive program similar to Utility A's.

A third issue involves how regulators and utilities should distribute among stockholders, managers, and ratepayers the dollar value of the savings that may result from an ICP-type program. This issue may be especially important from the regulator's viewpoint in situations where the base salaries of plant managers are not reduced at the time the incentive program is introduced.* Regulators may well question why power plant managers should be paid higher average salaries for doing only what they were initially hired to do, i.e., operate power plants efficiently.

A fourth issue is created by the target-setting process in Utility A's ICP, where a plant that does "too well" in one year may have its performance targets increased significantly for the next year. Utility A is well aware of this potential problem and tries to structure the targets in such a way that plant managers can continue to receive incentive compensation awards, even if the targets are set at levels that are increasingly more difficult to achieve. Plant managers, for obvious reasons, sometimes try to resist changes that make the targets harder to achieve. For example, Utility A indicates that plant managers may sometimes submit inflated operating and maintenance budgets at the start of a plan year. These budgets must then be reduced during the review process. However, Utility A also maintains that plant managers have, in general, bee very responsive to the plan. So far, the target levels have been increased and all participants appear to agree that they are achievable.

UTILITY B

Utility B is a combination electric/gas utility that serves about 1.3 million electricity customers and one million gas customers in a mid-western state. The utility has approximately 7,000 MW of electric generating capacity and is regulated by FERC and one state regulatory commission.

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* Utility A did not reduce base salaries when the ICP was implemented.

Program Description

In 1976 Utility B adopted an Executive Incentive Compensation Program (EICP) for both its electric and gas operations. The objective of the EICP is to improve the company's performance in selected target areas by providing competitive compensation levels for officers and other key executives. These compensation levels are intended to permit the company to attract and retain highly competent people and to motivate these people by providing incentives to improve both their and the company's performance. The program currently covers 60 executives, including 20 officers, which is 0.5 percent and 1.5 percent of the company's total and salaried work forces, respectively. Each executive participating in the program is responsible for an area that can significantly affect the company's overall operations and/or critical programs.

Under the EICP, a program participant may receive a bonus award each year that reflects his or her performance relative to a set of preselected performance targets, as well as the company's performance relative to a preselected net income target and to prices charged by other electric and gas utilities. More specifically, the company measures its performance on both its earnings and its ability to maintain or lower its gas and electric rates for customers relative to the historic relationship between its rates and those of other major U.S. investor-owned utilities.

The amount of EICP bonus pool that can be distributed to program participants is determined in several steps. First, each participant is assigned a standard incentive compensation award, which varies from 10 percent of the participant's year-end base salary for lower-level executives to 35 percent for upper-level executives. Both the EICP and the base salaries of participants are structured so that when taken together, a participant's total compensation is competitive with that of other major comparably sized, non-utility industrial corporations. While salary grade mid-points plus standard incentive compensation payments are fully competitive for lower-level executives, they are somewhat conservative for higher-level executives. However, as discussed in more detail below, if Utility B's corporate performance targets are met, the standard incentive compensation award for a higher-level executive may be adjusted upward so that his relatively low compensation (defined by the mid-point of the executive's salary grade plus his standard incentive compensation award) is offset.

At the beginning of each year, the company's Board of Directors sets a net income target for the utility. The sum of the standard incentive compensation awards of EICP participants is then adjusted up or down as the company's actual net income varies from this target. For each percentage point that the utility's actual net income exceeds (falls below) the target, the EICP bonus pool is increased (reduced) by four percent. If 75 percent of the net income target is not achieved, the EICP bonus pool is set at zero and no incentive compensation bonuses are paid for the year.

The EICP bonus pool is then divided into two equal parts. One part is adjusted to reflect the company's performance in maintaining or lowering the relationship of its electricity rates to those of other major utilities; the second part is adjusted analogously to reflect the company's performance with respect to its gas rates.

Adjustments to the electricity part of the EICP bonus pool again focus on comparisons of Utility B's current and historic electricity prices relative to those of other electric utilities. Specifically, the average revenue per kWh sold by Utility B in a current year is compared to the average revenue per kWh sold by the ten largest investor-owned utilities in the United States during the same year. The ratio of Utility B's average rate to the sample utilities' average rate is expressed as a percentage (P_t). Similarly, each year, the ratio of Utility B's average rate per kWh over the previous five years to the sample utilities' average rate for the same time period is expressed as a percentage ($\bar{P}$). These two percentages (P_t and $\bar{P}$) are used to adjust the EICP bonus pool up or down. For example, the electricity part of the EICP bonus pool is adjusted up (down) as the company's rate relationship during the current performance year is lower than (exceeds) its rate relationship during the previous five-year period. The adjustment formula used when the company's rate performance is improving is shown below. An analogous adjustment is used when performance is worsening. This results in the performance/adjustment schedule depicted in Exhibit G.3.

ADJUSTMENT FORMULA FOR IMPROVED RATE PERFORMANCE

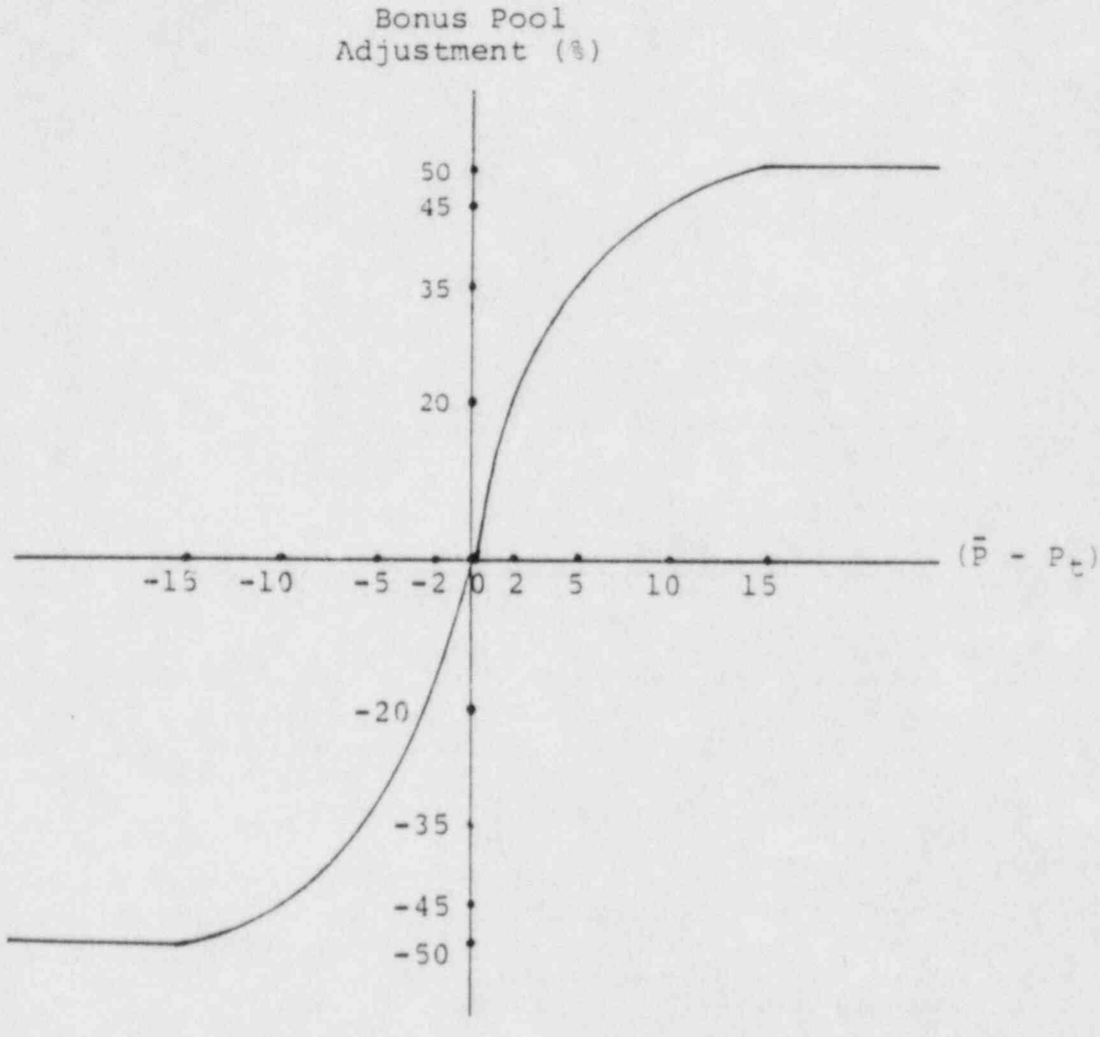
$\bar{P} - P_t$ (%)	Adjustment to EICP Bonus Pool (%)	Maximum Adjustment to EICP Bonus Pool (%)
0 to 2.00	$10 (\bar{P} - P_t)$	20
2.01 to 5.00	$20 + 5 (\bar{P} - P_t - 2)$	35
5.01 to 10.00	$35 + 2 (\bar{P} - P_t - 5)$	45
10.01 to 15.00	$45 + 1 (\bar{P} - P_t - 10)$	50
Over 15.00	$50 + 0 (\bar{P} - P_t - 1)$	50

The gas portion of the bonus pool is adjusted in a similar manner. This adjustment is based on comparisons of the company's current and five-year average gas rates (average revenue per 1,000 cubic feet sold) with those of the ten largest U.S. investor-owned gas utilities. The P_t and $\bar{P}$ ratios of current and five-year average rates for the company's gas operations are developed in the manner described above for its electric operations. A formula similar to that shown above is then used to complete the adjustment to the gas portion of the EICP bonus pool.

The sum of the adjusted electricity and gas parts becomes the actual EICP bonus pool, subject to two restrictions. First, the actual bonus pool can never exceed 150 percent of the sum of the standard incentive compensation awards for the program's participants. Second, the pool may not exceed 120 percent of the aggregate standard incentive compensation of the eligible participants unless the earnings performance target is met and neither the company's relative electric nor relative gas rates worsen. The bonus pool can, however, be set at zero, as noted above. The actual EICP bonus pool has exceeded the sum of the standard incentive compensation awards in only one year of the last six years.

Exhibit G.3

EFFECT OF RELATIVE ELECTRIC RATE POSITION
ON SIZE OF EICP BONUS POOL



The EICP bonus pool is distributed to individual participants (excluding the company's President and Chairman) in the following manner.* First, a par amount is set for each participant. The par amount is roughly equal to the participant's standard incentive compensation award multiplied by the ratio of the adjusted EICP bonus pool to the unadjusted EICP bonus pool. Second, this par amount is adjusted subjectively by the Chairman and the President based upon an evaluation of the participant's performance. The range of awards may vary from 50 percent to 150 percent of the par amounts, except that no bonus award is paid unless warranted by performance. The typical award received by a participant is equal to his par amount, subject to an adjustment by the Chairman and the President to reflect special performance considerations. Because the aggregate amount of the bonus awards cannot exceed the size of the total EICP pool, each participant's award is implicitly based upon the performance of other plan participants as well as his or her own performance.

Program Administration

A personal objectives program is used to assist in evaluating each participant's performance. Under this program, each eligible participant establishes a set of objectives which must be approved by higher level management before the performance year begins. The participant's performance is then evaluated against these objectives at a formal year-end review.

At least six specific objectives must be established for each participant. The objectives must define reasonably attainable targets that will contribute significantly to meeting the company's earnings and rates objectives. They also must be stated in such a way that the participant's performance can be clearly measured, either on a quantitative or qualitative basis. Although most of the objectives focus on current year results, long-range objectives may also be included. In such cases, specific sub-goals tied to these longer-term objectives must be established for the current program year. Under the EICP, a participant may defer all or part of his bonus award in a current year and invest it in various tax-deferred programs. The total

* EICP bonus awards for the Chairman and President are determined by the company's Committee on Executive Organization and Development and are approved by the company's Board of Directors.

administrative costs of the program are estimated to be about $5,000 annually. The major portion of these administrative costs is represented by the salaries of the various employees of Utility B who administer the program.

Program Results

Utility B was unable to supply quantitative data on the results of its EICP. To date, however, the executives covered by the EICP seem pleased with the program, which has had a payout in every year since its inception. However, the 1980 and 1981 awards were substantially reduced because of economic conditions in the utility's service areas.

The program's administrators feel that the program has united the company's management team and helped Utility B to attract executives from non-utility industries, who have brought new approaches and innovative perspectives to the company. In terms of improving the program, the company sees a need to follow-up the personal objectives program more closely and to develop an additional longer-term incentive program that would tie a significant part of executive compensation to success in achieving long-term corporate goals.

Program Issues

In developing the EICP, Utility B has taken a different approach to addressing several incentive structure and costing issues than Utilities A and C. First, the size of the EICP bonus pool depends both on meeting corporate profit targets and on improving or maintaining the relationship between the company's average rates and rates for other electric and gas utilities. Second, because the base salaries plus standard incentive compensation awards of higher-level executives is set below those for similar employment positions in non-utility industries, the EICP allows higher-level executives to earn up to 150 percent of their par amounts if both the individuals and the company perform well. Thus, the greatest monetary incentives under the EICP are available to the higher-level executives who can most directly affect Utility B's performance. At their lower relative compensation level, the potentially large bonus award provides an aggressive executive with an opportunity to earn a compensation level that is probably higher than for comparable positions in non-utility industries. However, higher compensation is tied to superior corporate and individual performance. Finally, individual performance targets, which are often subjective in nature, affect only individual bonus awards and not the size of the EICP bonus pool. Put another way, the overall size of the EICP bonus pool depends only on the two measures that are most important for consumers (rates) and shareholders (profitability).

UTILITY C

Utility C is a holding company comprised of several subsidiary companies that generate and sell electricity. Each of the subsidiaries is regulated by FERC and a different state regulatory commission. The total generating capacity operated by Utility C exceeds 10,000 MW.

Program Description

In 1982, Utility C implemented a Productivity Improvement Plan (PIP). The plan has three major features for its participants:

- The PIP requires each program participant to set individual performance objectives. These objectives will play a key role in the yearly evaluation of the participant's overall work performance.
- Financial incentives are provided for program participants to meet their individual objectives; collectively, these objectives contribute to improvements in corporate performance.
- Potential compensation levels for individuals are set high enough to enable Utility C to attract, retain, and motivate its key management employees.

Utility C classifies its employees on the basis of a formal job evaluation system. Under the PIP program, employees that occupy positions with a job evaluation rating above a specified level are eligible to participate in the program. Approximately 0.5 percent of Utility C's employees meet this criterion and are PIP participants. These employees make up the upper management group in Utility C, and include the President of Utility C and the Chief Executive Officer of each of the subsidiary companies.*

The PIP program has two major incentive components, both of which are linked to Utility C's return on common equity (ROCE). The first component focuses on the actual performance of each PIP participant relative to the annual performance objectives that are set for the participant. The second component focuses on the company's overall financial performance relative to the financial performance objectives set for the company. A PIP participant can receive an annual bonus award under one or both of these program components. Specifically, if a participant meets his annual performance objectives in a particular year, he is eligible for a bonus award under the individual performance component. Similarly, if Utility C achieves selected corporate financial performance objectives in that year, a participant may receive another bonus award under the corporate financial performance component.

Maximum bonus award levels are formulated each year for the individual performance component (IPC) and the corporate financial performance component (CFPC). The maximum level of IPC bonus awards is determined annually be comparing Utility C's average return on common equity with the average ROCE in the same year of a peer group of 16 utilities selected by Utility C.

More specifically, the maximum level of IPC bonus awards is set as a percentage of the sum of the salary range mid-points of the PIP participants; this percentage is, in turn, determined by the ROCE of Utility C relative to the ROCE of the 16 other utilities. As shown below, if Utility C earns an annual ROCE equal to or greater than the ROCE of the four utilities with the highest ROCE in the 16-utility peer group, the maximum level of IPC bonus awards is set at 10 percent of the sum of the salary range mid-points of the PIP participants. If Utility C's ROCE is less than or equal to the ROCE of the four utilities with the lowest ROCE in the 16-utility peer group, the maximum level of IPC bonus awards is zero.**

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* As we noted in the preceding sections, top corporate executives are excluded from the program implemented by Utility A and included in Utility B's program.

** If Utility C's earnings are insufficient to fund the current dividend, the maximum level of IPC bonus awards will be set at zero regardless of the ROCE comparisons.

IPC BONUS AWARDS

ROCE Rank of Utility C	Maximum Level of IPC Bonus Awards as Percentage of Sum of Participants' Salary Range Mid-Points	Participant Bonus Award as Percentage of Salary Range Mid-Point
4th Quartile of Peer Group Utilities	10.0	0-20
3rd Quartile of Peer Group Utilities	7.5	0-15
2nd Quartile of Peer Group Utilities	5.0	0-10
1st Quartile of Peer Group Utilities	0.0	0

As can be seen from the table, the bonus award that a PIP participant is eligible to receive ranges from zero to 20 percent of the participant's salary range mid-point for the year. The size of a participant's award is determined in a formal year-end evaluation of the participant's performance during the year relative to the performance objectives that were set the beginning of the year. Since the sum of the awards made cannot exceed the maximum level of IPC bonus awards, an individual's IPC bonus award implicitly depends not only on the participant's own performance, but also on the participant's performance relative to other participants in the plan. Individual performance awards are paid as soon as possible after the utility's year-end closing and the plan provides for the participant to elect a deferral of payment, which may provide tax advantages to the participants.

The annual CFPC bonus awards are determined by three factors:

1. The salary range mid-points of the PIP participants

2. Utility C's average ROCE relative to a ROCE target for a four-year period, and

3. The average ROCE of Utility C over a four-year period relative to the average ROCE of the peer group of utilities over the same period.

In general, the aggregate level of CFPC bonus awards to PIP participants will be larger in a particular year when three variables are higher:

1. The sum of the salary range mid-points for the PIP participants

2. Utility C's average ROCE in the year relative to its target ROCE for the four-year period, and

3. Utility C's four-year average ROCE relative to the average ROCE of the 16 other utilities.

An individual participant's potential bonus award under the CFPC is initially determined by the job evaluation rating of his position in the company. As shown below, a participant may receive a CFPC bonus award ranging from 8 percent to 20 percent of his annual salary range mid-point, depending on the job evaluation rating of his position.

JOB EVALUATION RATING AND POTENTIAL CFPC BONUS AWARD

Job Evaluation Rating	Potential Award as Percentage of Salary Range Mid-Point Within Rating Level
Level 1	20
Level 2	16
Level 3	12
Level 4	8

Higher percentage award opportunities are offered to higher-level executives, presumably because their decisions and actions have greater potential effects on corporate performance.

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

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
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.

made by the participant's immediate supervisor and reviewed by the next level supervisor. The Chief Executive Officer of each subsidiary company in Utility C must approve the bonus awards to individuals and, if necessary, make adjustments so that the sum of the individual awards does not exceed the maximum level of aggregate bonus awards.

Performance objectives for the Chief Executive Officer of each subsidiary company are developed in conjunction with the compensation committee of the subsidiary's Board of Directors. The compensation committee of each subsidiary company's Board of Directors then reviews the performance of its Chief Executive Officer and recommends an individual performance bonus award to its Board of Directors. The entire Board of the subsidiary must then approve any IPC bonus award to its Chief Executive Officer.

In a similar manner, performance objectives for the President of Utility C are developed in conjunction with the compensation committee of the holding company's Board of Directors and approved by the entire Board of Utility C. The President's performance against these objectives is reviewed by the compensation committee, which is responsible for recommending to the entire Board any IPC bonus award to the President. The Board of Utility C must then decide whether to approve the recommended award.

Program Results

Because the PIP program has only been in effect since July 1982, no program results have been determined.

Utility C estimates that if the ROCE goals and the goals of each PIP participant were achieved (i.e., each participant received his maximum IPC and CFPC bonus awards, the cost of the program in terms of bonus awards would still be less than 0.3 percent of the utility's pre-tax earnings. This amount is quite small relative to the potential benefits of a one-percent increase in the company's ROCE.

Program Issues

Three aspects of the PIP program are interesting from the perspectives of both regulators and other utilities that might be considering alternative structures for management incentive compensation programs. First, the PIP program deals properly with the issue of the time frame over which an incentive program should be focused. In particular, of the three management incentive compensation programs, we reviewed, the PIP program is one of two programs (Utility B's program is the other) that focuses most clearly on longer-term performance objectives, specifically, through its corporate financial performance component. Utility C's use of four-year performance averages encourages the contemplation of the long-run nature of major management decisions.

Second, the PIP program focuses on the major concern of shareholders (i.e., ROCE)* as well as the concerns of regulators and ratepayers. Under the CFPC, the size of a participant's potential bonus award depends only on the achievement of absolute and relative ROCE targets for Utility C. In addition, the IPC bonus awards of selected PIP participants focus on two important corporate objectives: improving the quality of service to customers and minimizing the cost of delivered energy by planning and operating more efficiently. From the perspective of regulators and ratepayers, these two objectives should be important elements in decisions about the size of potential bonus awards to PIP participants.

Third, with respect to who should pay for an incentive program, Utility C feels that regulators will allow the company to treat bonuses under the PIP program as normal labor expenses for ratemaking purposes. The company contends that, over time, the program will certainly be

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* A utility might consider focusing an incentive program on growth in earnings per share instead of improvements in ROCE. However, an earnings per share focus may not be of the greatest interest to a utility's shareholders. Specifically, recent research has indicated that earnings per share growth does not lead to shareholder value if a company's return on equity (ROCE) is less than the return on equity a shareholder could receive on an investment with similar risk. Thus, programs designed to increase shareholder value should focus on incentives that promote the company's ability to earn an ROCE higher than its cost of equity and higher than the ROCE of the company's competitors. See: Brindisi, L. J., Jr. "Why Executive Compensation Programs Go Wrong," Wall Street Journal, June 14, 1982.

cost-effective and produce major benefits to ratepayers as well as shareholders.

APPENDIX H

CONSTRUCTION COST CONTROL INCENTIVE PROGRAMS: ALASKA NATURAL GAS TRANSPORTATION SYSTEM AND NINE MILE POINT NO. 2 NUCLEAR STATION

Two large-scale construction projects that have had construction cost control incentive programs imposed upon them are reviewed here. They are the Alaska Natural Gas Transportation System (ANGTS) and the Nine Mile Point No. 2 nuclear station (NMP-2). Although both programs are basically similar to the recommended construction cost control incentive program described in Chapter 5, the ANGTS and NMP-2 programs are deficient in two areas. First, neither program was conceived and implemented early enough to obtain unbiased cost estimates for its construction. Second, both programs have incentive rates of return that provide, at best, only weak incentives to control costs. We discuss each program below.

Plan Descriptions

The ANGTS is a proposed 4,800 mile, large diameter pipeline system which will be used to transport natural gas from Prudhoe Bay, Alaska to parts of the U.S. and Canada. The southern half of the system was completed in 1982 and carries Canadian export gas from Alberta; the northern half of the system is now scheduled for completion in 1989. When it is fully completed, the system will carry approximately four percent of our nation's current natural gas consumption (one percent of total U.S. energy consumption) and will cost in excess of $40 billion "as spent" dollars, making it one of the largest projects in the world. The project has been broken into four separate segments: the Alaskan, Canadian, and Eastern and Western lower-48 legs. All but the Western leg are completely new systems (rather than expansions of an existing system). All of the systems except the Canadian leg are also subject to a construction cost control incentive program that incorporates an incentive rate of return plan (IROR). Under this plan, FERC sets the rate of return to be earned on the project's equity capital as a function of its cost performance. The ANGTS IROR was devised and imposed only after the project had been chosen from three competing systems, but before any construction had begun.

NMP-2 is a 1.08 million kilowatt nuclear-powered electric generating plant currently under construction on the southern shore of Lake Ontario; it is scheduled for commercial operation in 1986. Five utilities are co-tenants of the plant, which was approximately 50 percent complete (in terms of direct outlays, using the sponsor's estimated total cost) when the New York State Public Service Commission (PSC) held hearings on proposals to abandon the project. Given the substantial increase in the estimated completed cost and the continuing uncertainty of the final completed cost, the PSC decided to impose an IROR "to encourage the expeditious and cost-effective implementation of the Nine Mile project."* The plan calls for a constant sharing factor of 20 percent of the change in revenue requirements resulting from any cost overrun or underrun from the target level of $4.6 billion.

Investment Community Reactions

The receptivity of the investment community to the FERC and PSC incentive systems has been less than positive. In the ANGTS case, the handful of pipeline companies that were equity sponsors initially viewed the scheme with a great deal of skepticism, but once its details were worked out and understood, these sponsors appeared willing to tolerate the imposition.

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* State of New York Public Service Commission. "Establishment of an Incentive Rate of Return Plan for the Ratemaking Treatment of Future Construction Costs of the Nine Mile No. 2 Nuclear Generating Plant." Case No. 28059, February 23, 1982.

In the NMP-2 case, the reaction has been much more negative. For example, Moody's carried an article which began by stating that their review and downgrading of one co-tenant's bonds was prompted by the PSC's adoption of the IROR for NMP-2. A careful reading of the article clearly demonstrates a bias: it focuses almost exclusively on the penalty side and makes such statements as "For one thing, the IROR abrogates the fundamental assumption of assured capital recovery of prudently invested capital.* However, the NMP-2 plan explicitly permits the full recovery of all prudently invested capital, the full recovery of all interest on debt, and, at worst, a return on equity capital in excess of 11.3 percent.

Comparison and Evaluation of the ANGTS and NMP-2 Plans

The IROR plan imposed by the FERC on the ANGTS departs from the IROR system described in Chapter 5 in two ways. First, the plan was conceived after the ANGTS' sponsors had submitted their initial cost estimates. Because the FERC could not reasonably use the initial cost estimate as a basis for the projected capital cost (PCC), the sponsors were able to resubmit their cost estimates. While little argument was raised on the revised estimates for the Eastern leg, there was considerable controversy over the revised estimates for the Alaskan section. The most recent report on the U.S. portion of the Eastern leg (which is approximately 80 percent complete) was that the leg's PCC was \$1.237 billion and the anticipated actual capital cost was \$1.190 billion, resulting in a cost performance ratio (CPR) of 0.962, almost four percent under the project's projected cost. The Commission has not yet specified the numbers it will use for the Alaskan leg's projected capital cost base.

Second, the real degree of cost control incentive embodied in the entire ANGTS plan is questionable. Specifically, the eight percent level at which r_m (the rate of return

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* Moody's Investor Service. "Impact of a Recent NYSPSC Order on Some New York State Electric Utilities." Moody's Bond Survey, May 17, 1982, pp. 2042-2043.

level the sponsors will be allowed to earn on the dollar value of deviations in actual completed construction costs from projected costs) was set is high relative to the rate for government bonds of similar duration when investment tax credits effects are considered.

The IROR plan for NMP-2 was also implemented after construction began. In addition, the NMP-2 plan, like the ANGTS plan, provided only a moderate cost-control incentive. Specifically, as we discuss in more detail below, the after-tax marginal rate of return associated with the proposed plan was 11.3 percent.

While it was expressed by the PSC in its order as a 20 percent cost-sharing plan, it can be shown that such a plan is equivalent to an incentive rate return. If:

- A = actual completed cost (including AFUDC)
- P = projected completed cost (including AFUDC)
- r = before-tax fixed charge (interest, return on equity, income taxes, and depreciation) per dollar of capital
- q = normal cost of equity (after corporate taxes)
- f = cost-saving fraction by which revenue requirements are to be shared between ratepayers and equity
- z = equity capital ratio
- t = marginal tax rate,

then:

- The difference in revenue requirements calculated on the basis of actual performance compared to projected performance is r (A-P);
- Equity investment is (zA);
- Allowing a normal rate of return on the equity investment, but reducing the total revenue requirement by a fraction of the differential requirement calculated (r (A-P)) results in after-tax equity earnings of qz - fr(A-P)(1-t);
- The average after-tax rate of return on equity will be:

$$(1) \quad \frac{\text{after-tax equity earnings}}{\text{equity investment}} = \frac{qzA - fr(1-t)(A-P)}{zA}$$

$$= q - \frac{fr\ (1-t)}{z} \left[\frac{A-P}{A}\right]; \text{ and}$$

- The marginal rate of return on equity will be

$$(2) \quad \frac{\Delta \text{ after-tax equity earnings}}{\Delta \text{ equity investment}} = q - \frac{fr(1-t)}{z}.$$

Thus, the NMP-2 percentage-sharing plan effectively is an incentive rate-of-return plan, with the average rate of return expressed as a function of the cost performance ratio (A/P) according to equation (1), and an embedded constant marginal rate of return on equity, as specified by equation (2).*

In the NMP-2 case, the parameter values used by the PSC on prospective costs in its Notice on the plan** were:

$r = .2189$

$q = .17$

$f = .20$

$z = .42$

$t = .45$

resulting in the schedule shown in Exhibit H.1. Note that the after-tax marginal rate of return is:

$$.17 - \frac{(.20)(.2189)(1-.45)}{.42} = 113,$$

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* Equation (1) is identical to equation (4) in Chapter 5 with $r_m = k - \frac{fr(1-t)}{d}$.

** State of New York Public Service Commission, op. cit.

Exhibit H.1

NMP-2 IROR PLAN ADOPTED BY NEW YORK PSC
(Millions of dollars where applicable)

(1) Total Project Cost	(2) Projected Cost	(3) Over/Under Target*	(4) Total Change From Target Revenues	(5) Revenue Reduction	(6) Stockholders' Prospective Capital	(7) Stockholders' Prospective Income	(8) Rate of Stockholders' Prospective Capital	(9) Incremental Rate of Return
3,100	1,700	-1,500	-328.4	65.7	714	157.5	22.0	-
3,600	2,200	-1,000	-218.9	43.8	924	181.2	19.6	11.3
4,100	2,700	- 500	-109.5	21.9	1,134	204.8	18.1	11.3
4,600	3,200	0	0	0	1,344	228.5	17.0	11.3
5,100	3,700	500	109.5	-21.9	1,554	252.1	16.2	11.3
5,600	4,200	1,000	218.9	-43.8	1,764	275.8	15.6	11.3
6,100	4,700	1,500	328.4	-65.7	1,974	299.4	15.2	11.3
6,600	5,200	2,000	437.8	-87.6	2,184	323.1	14.8	11.3

(3) = A-P = [2] - 3,200

(4) = r(A-P) = .2189 x [3]

(5) = fr(A-P) = .2 x [4]

(6) = (z) [2] = .42 x [2]

(7) = (q) [6] + (1-t) x [5] = .17 x [6] + (1-.45) x [5]

(8) = [7]/[6] (or equation 1)

(9) = Δ [7]/ Δ [6] (or equation 2)

which implies only a moderate incentive.* From equation (2), it can be seen that if a larger share of the incremental revenue (f) had been specified, the incremental rate would be lower.

A major difference between the plan for ANGTS and the plan for NMP-2 lies in the relative degree of procedural detail that each plan incorporates for changes in a project's scope. While FERC explicitly limited the conditions which would trigger a possible scope change (permitting the PCC component of the cost performance ratio to be adjusted), it did allow major design changes compelled by changes in federal or state law. By comparison, the PSC simply stated:

> The co-tenants and other parties will have the opportunity, at the time rates are set that include NMP-2 expenditures, to request modification of the target figure for increased or decreased expenditures resulting from extraordinary events.**

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* The PSC had a built-in, non-binding constraint regarding the marginal rate of return implicit in its scheme. Specifically, it provided that the average return on equity under the IROR plan could not be set at less than half the normal rate. But half of 17 percent (k) is 8.5 percent, which is well below the marginal rate of 11.3 percent embedded in parameter values used by the PSC in its Notice. As we demonstated in Chapter 5, the average rate can never fall below the marginal rate if it begins above it. Therefore, the PSC's constraint is non-binding.

** State of New York Public Service Commission. Opinion and Order Concluding Inquiry into Financial and Economic Cost Implications of Constructing the Nine Mile Point No. 2 Nuclear Station. Case No. 28059, April 16, 1982, Appendix 1, page 1.

In its opinion, it provided some guidance as to the term "extraordinary events":

> We recognize that in providing an exclusion only for costs relating to extraordinary events, the co-tenants will bear a penalty for some potential cost overruns that are not within the control of management. However, we believe that it is proper for several reasons to include such overruns to the extent they are not extraordinary. For example, the in-service date, which is to a great extent under the co-tenants' control, has an impact on costs resulting from changing interest, AFUDC and regulatory requirements. And, the longer a plant is under construction, the greater its exposure to such costs. Routine NRC scope changes also are not directly under management's control. However, the co-tenants have the ability to anticipate and implement such changes in an efficient or inefficient manner. In fact, the ability to respond to change may have a more important impact on project costs than the cost of the actual change itself.*

The difference in the treatment of inflation and extraordinary events between the two IROR plans is most likely a function of their relative size and degree of project completion at the time the IRORs were imposed. Many parties in the NMP-2 case contend that the plan would never have been acceptable if the project was at its infancy, because the NMP-2 plan, unlike the ANGST plans, lacks explicit inflation indexing and clearly defined and comprehensive extraordinary events. The parties contend that this lack would have created too much uncertainty for both debt and equity investors. This suggests that the greater complexity of the ANGTS plan may be necessary in order to achieve investor acceptance for newly proposed projects.

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* _Ibid_., pp. 61-62.

Implementation Issues

The documents and statements issued by FERC on the ANGTS plan provide some useful insights into the practical aspects of implementing an incentive rate of return program. For example, the FERC set the rate r_m on the U.S. sections of the system at eight percent. The Commission justified this rate on the grounds that it was sufficiently below the rate of return that equity investors could earn elsewhere (the cost of equity capital), even after allowing for some financial leverage employed by the equity supplier.* In setting k, the Commission chose to "derive" this number by summing three terms: an "operation phase" rate (normal pipeline risk), a "project risk premium," and an "IROR risk premium." The project risk premium was added to recognize that the ANGTS project is more risky than a simple pipeline extension project. The IROR risk premium was added to compensate for the uncertainty created by the IROR system itself. For the Alaska section, the factors were:

Operation Phase Rate	14.0
Project Risk Premium	2.0
IROR Risk Premium	1.5
k	17.5

* Unfortunately, the effective after-tax marginal rate is much higher than eight percent, due to an anachronistic condition in the Federal tax code. Under the Revenue Act of 1971, the FERC is prohibited from directly or indirectly considering the effect of the Investment Tax Credit (ITC) in its rate-setting. The Commission's IROR order, therefore, makes no reference to the substantial impacts the ITC has on the return to equity holders. It can be shown that with a 75/25 debt/equity ratio and virtually all of marginal outlays qualifying for an ITC of 10 percent, the marginal return to equity associated with a nominal return of eight percent after tax is close to 16 percent.

This rate is the rate of return on equity that will be allowed throughout the life of the project. If it is completed at the projected capital cost.* In the ANGTS case, the FERC also decided to utilize a one-time rate base adjustment procedure:

> The Commission has adopted the one-time adjustment approach for two reasons. First, the use of a one-time adjustment simplifies the determination of just and reasonable rates of return in the future, because the risks attached to the construction phase, including the risk of the IROR mechanism itself, are already recognized in the adjusted capital structure and rate base. By compensating for these risks through an adjustment to the project's rate base, future rate of return determinations need only address project risks and financial market conditions at the time of determination, not those risks associated with the construction of the project which took place in the past.
>
> The second reason is to simplify future financing for, and rate determinations on, expansions or looping of the ANGTS. The risks of participation in this project prior to and during construction are significantly different from the risks associated with project investments made in the future when in an operational phase. The IROR mechanism is a concept developed to recognize the project sponsors' performance in the initial construction phase only, and the resulting adjustment should not affect the return on future investment in an

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* The Commission made a distinction that we have ignored here. The projected completion costs can be considered as a combination of a budgeted capital cost and an expected overrun. The budgeted capital cost would then be premised on conservative calculations, with its contingency factor containing only known uncertainties. The unknown unknowns ("unk-unks" in the trade) would then be incorporated into the expected overrun.

> expansion of that project. The one-time adjustment ensures this result without the need for separate return determinations for investments made in the ANGTS at different times.*

However, there is a third reason for the one-time adjustment approach which the Commission obviously did not wish to state. That is, by using a one-time rate base adjustment at the end of the construction period, all unique risk premiums are clearly dealt with in a relatively short time frame. This is particularly important with respect to the Commission's credibility. While no party to the FERC proceedings suggested the Commission would later renege on the allowed return should it turn out to be very high, it is likely that equity investors would probably anticipate such an event, knowing that conditions, institutions, and people change over time and that the period over which the IROR is to be earned may be relatively long (20 to 30 years). Allowing "normal" rates after the one-time adjustment makes the IROR reward or penalty far less conspicuous over time.

The potential investor risk inherent in a changing regulatory environment was clearly stated by Standard & Poor's in its comments on the proposed IROR system for NMP-2:

> There can be no doubt that under-running the target can benefit the credit position of the sponsors. However, the binding ability of the PSC to allow the sponsors an opportunity to earn returns in excess of their cost of capital seems problematic. There is an underlying question as to whether the PSC has the authority to make binding decisions on future commissions. Presently, there is no guarantee that the "reward" could not be given back through legislative action or an adverse court ruling, which would not be unlikely given

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* Federal Energy Regulatory Commission. "Order Setting Values for Incentive Rate of Return, Establishing Inflation Adjustment and Change in Scope Procedures, and Determining Applicable Tariff Provisons." Order No. 31, June 8, 1979.

> the precedent setting nature of the proposal. Even assuming legal sanction, investors would question whether regulators would "come through" with an incentive return at a time when rates need to be raised to accommodate the new plant in rate base.*

In response, the PSC imposed a one-time rate base adjustment:

> After consideration of all of the comments, we will, however, amend the IROR plan to provide that any reward or penalty will be implemented through a one-time adjustment to each co-tenant's rate base or through a short-term amortization to income. Thus, when the amount of any underrun or overrun is known, and the revenue effect of the IROR determined, we will alter the co-tenant's rate base (or amortize the effects of the penalty to income) accordingly. By doing so, there will be no need to make such adjustments continually in rate cases over the life of the plant.**

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* Standard & Poor's Corporation. "Comments on Incentive/Penalty and Risk Sharing Mechanisms." Case No. 28059, State of New York Public Service Commission, March 29, 1982.

** State of New York Public Service Commission. Opinion and Order Concluding Inquiry into Financial and Economic Cost Implications of Constructing the Nine Mile Point No. 2 Nuclear Station, op. cit.

APPENDIX I

THE NEW MEXICO COST OF SERVICE INDEX

From 1975 until early 1982, the New Mexico Public Service Commission used a cost of service index (COSI) for adjusting the rates of one utility in its jurisdiction, the Public Service Company of New Mexico (PNM). The use of the COSI represented an important departure from traditional regulatory procedures in that it allowed for frequent, comprehensive rate adjustments to maintain PNM's earned return on equity within a specified margin of its allowed return. Moreover, these rate adjustments were accomplished without going through the traditional rate case process. In this way, the COSI procedure was intended to protect the utility against anticipated increases in its cost of service that would otherwise lead to earnings erosion and a higher cost of capital. Ultimately, reductions in PNM's cost of capital were expected to reduce charges to its ratepayers (all other things held unchanged).

Because of the innovativeness of the COSI procedure and its potential for reducing a utility's cost of capital, we reviewed and evaluated COSI as a potential component of an incentive regulation program. On the basis of this review, we conclude that, as applied in New Mexico, the COSI program would not generally be a viable component of an incentive program to improve performance in the electric utility industry and minimize costs to ratepayers. As alternatives to the New Mexico formulation of COSI, we identified a number of modifications to the New Mexico program that would tend to reduce the adverse incentive effects on a utility's production efficiency. However, it should be noted that these modifications will also tend to reduce the efficacy of COSI in lowering a firm's cost of capital.

This appendix focuses on seven aspects of the use of COSI in New Mexico. First, we describe the circumstances that led to the adoption of COSI, particularly the economic conditions and regulatory setting of PNM in 1974 and 1975. In describing these circumstances, the reasons for the adoption of COSI are also discussed. Second, the operation of COSI is described, both in its originally adopted form and its form after 1978, when the operation of COSI changed significantly. Third, we present a discussion of the index's effect on PNM's economic efficiency; this discussion centers on the economic impacts of COSI on incentives for efficient management by PNM officials. Fourth, we examine the administrative costs of COSI borne by the New Mexico Public Service Commission. Fifth, we discuss the effect of COSI on the utility's cost of capital. Sixth, in light of the experience of PNM's consumers, regulators, and company officials with COSI, we evaluate whether or not COSI worked. Finally, we consider possible modifications to COSI which would encourage economic efficiency in PNM's operations.

THE ADOPTION OF COSI

Two factors contributed to the adoption of COSI for PNM: the company's poor and increasingly uncertain financial condition, and the regulatory burden faced by the New Mexico Public Service Commission. In the rate case that preceded the adoption of COSI (Case 1130), the Commission granted PNM a 14 percent allowed return on its jurisdictional common equity capital. However, due primarily to regulatory lag, PNM was unable to earn the return allowed by the Commission. For example, in 1974, the utility earned only 10.1 percent on its average jurisdictional common equity.

In addition, PNM faced a nearly overwhelming construction budget. Because the utility needed to convert its generation from oil to coal and expand its capacity to service the new customers attracted by New Mexico's sunbelt status and mining, PNM's five-year construction budget was $742 million, approximately to and one-half times its undepreciated original cost of plant at that time.

Further, the market value of PNM's common stock was substantially less than its book value, and sold for only two-thirds of its book value in late 1975. Coupled with its huge construction budget and recent inability to earn its allowed rate of return, the company faced a severe danger of having its AA bonds downrated by such rating services as Standard and Poor's and Moody's. A downrating or derating of its bonds not only would increase the company's interest costs for this substantial construction budget, but it would also eventually increase rates to its customers. In addition, a bond downrating would call the ability of PNM to raise capital into question. Therefore, the possibility existed that PNM would simply be unable to raise the capital necessary to build the plant required to serve the fastest-growing load in the nation. In this situation, COSI was viewed as a means of improving the likelihood that PNM would earn its allowed return and maintain efficient coverage of its interest and other fixed costs to prevent deterioration of its debt ratings, thus improving its ability to raise capital. Indeed, by reducing the variance in its earnings and operating income levels, it was posited that COSI would lead to reductions in the cost of capital for financing its ambitious construction program.

A second reason for the adoption of COSI, although somewhat less important than the first, was still significant, especially in the eyes of the Commission. The Commission has less than ten members and regulates 74 electric, natural gas, and water utilities (26 of these are electric utilities). Faced with the prospect of annual or semi-annual rate cases from each of its 26 electric utilities and a rate case every year to 18 months for the natural gas and water utilities, the Commission was clearly overwhelmed. The sponsors of COSI argued that COSI might remove both the Commission staff and the companies from the "tyranny of the rate cycle." Whether or not COSI actually achieved these goals will be discussed later in this appendix.

THE OPERATION OF COSI

In this section, we address two formulations of the COSI program. The first, adopted in Case 1196, was in effect from mid-1975 through the end of 1978. COSI was then modified significantly in 1978; this formulation remained in effect until COSI was eliminated by action of the state legislature of New Mexico early in 1982.

As originally constituted, COSI involved a quarterly adjustment to rates. This adjustment applied only to the consumption or energy charge; demand charges were not affected. Three weeks after the end of each quarter, PNM submitted its costs for the year ending with the most recent quarter. It also submitted its revenues for the year, recalculated by pricing the quantities of electricity sold in each service category as if the last quarter's COSI were in effect. This process assumed that consumers, faced with a COSI-induced price increase or decrease, would not react to that price change by altering the quantity of electricity they demanded. Thus, this recalculation of revenues assumed a zero demand elasticity.

PNM then took its actual costs and its hypothetical revenues and calculated the firm's return to common jurisdictional equity capital over the previous 12 months. If that return was between 13.5 and 14.5 percent, no adjustment to the COSI surcharge was made. If the return was below 13.5 percent, the COSI rate surcharge was adjusted upward (again assuming a zero demand elasticity) so that revenues would have been just sufficient over the previous year to allow the utility to earn exactly 13.5 percent on its common jurisdictional equity. If the calculated return was greater than 14.5 percent, the COSI surcharge was adjusted downward so that the utility would have earned exactly 14.5 percent. This range of equity return was adopted in Case 1196, subject to change. If the cost of equity capital rise or decreased significantly, the Commission expected to change this band commensurately.

Following the company's submission of its COSI factor, the Commission staff was then given 10 days (including weekends) to verify the company's calculations. If, during the 10-day period, the staff found some of the calculations to be in error or some of the expenditures to be questionable, it could petition the Commission to stop the COSI adjustment from going into effect. If the staff did not make any objection during the 10-day period, the COSI adjustment would go into effect on the first day of the month following the end of the quarter (i.e., if the quarter ended March 31, the COSI adjustment would go into effect on May 1).

As originally instituted, COSI had several effects on both the Commission and PNM. First, the COSI adjustments (in effect, "mini" rate cases) came at predictable spacing intervals. With a rate adjustment every three months, regulatory lag was shortened to a very predictable three months. Second, the Commission's oversight of PNM's expenditures was drastically reduced, at least during the COSI review process. The Commission staff, limited as it was in that period, was unable to do anything more than simply check the addition of the columns of numbers submitted by PNM. As a result, there was no effective regulatory oversight of company expenditures by the Commission. Finally, although COSI had been implemented with the expectation of stabilizing PNM's equity return at between 13.5 and 14.5 percent, we will see later in this section that the stabilization did occur, but it was not within this band.

On December 29, 1978, the Commission, in Case 1419, dramatically modified the COSI procedure. First, it eliminated the quarterly adjustment in favor of an annual adjustment. This annual adjustment was really a series of adjustments that were to occur over a six-month period. Under this revised adjustment procedure, PNM was to file a cost and revenue statement each December that was based on 10-month actual/two-month projected data. (This statement was to follow an eight-month actual/four-month projected statement made by PNM in October.) On January 1, a preliminary COSI surcharge equivalent to 90 percent of the surcharge necessary to bring it to a 15.5 percent return on equity would go into effect without an audit. If the surcharge change would result in a rate increase of five percent or more, the Commission would hold a full review. In addition, the Commission could insert a revised COSI surcharge in the March billing that would reflect PNM's actual cost and revenue experience in the preceding 12 months. Finally, a formal COSI hearing was to be held each year and a decision on the final COSI surcharge to be made on May 31. The final COSI surcharge was reduced on June 1 relative to its January 1 or March 1 level, the company was required to refund the "excess" revenues, with a 15.5 percent interest applied to the refund amount.

Relative to the earlier COSI procedure, the more recent procedure lengthened the regulatory lag period to one year. The staff was given a significantly greater amount of time to review the company's submissions, from 10 days under the first procedure to as much as three months in the later procedure. Finally, the initial rate of return band (13.5 to 14.5 percent) was eliminated in favor of a point estimate of the cost of capital (15.5 percent).

Early in 1982, the legislature of the State of New Mexico eliminated this COSI procedure through Bill 167. After describing all of the elements of a traditional rate case in some detail, Section 10-E of the Bill states "any increase in rates or charges for the utility commodity based upon cost factors other than taxes or cost of fuel, gas or purchase power filed for after the effective date of this section shall be permitted only after notice and hearing as provided by this section." Essentially, this bill eliminated the automatic rate increase nature of COSI, and substituted instead a traditional rate case, which will come at predictable one-year interals. What is left in New Mexico is thus a procedure that is a great deal different from its radical experiment with COSI.

INCENTIVES FOR ECONOMIC EFFICIENCY UNDER COSI

In its first form, COSI had a substantial negative effect on incentives for economic efficiency. These effects derive principally from COSI's effect on regulatory lag. In addition, COSI had several secondary effects on PNM's efficiency incentives. We discuss these incentive effects in the following pages.

Effect of COSI On Regulatory Lag

Alfred Kahn described regulatory lag as follows:

> The regulatory lag--the inevitable delay that regulation imposes in the downward adjustment of rate levels that produce excessive rates of return and in the upward adjustments ordinarily

> called for if profits are too low--is thus to be regarded not as a deplorable imperfection of regulation but as a positive advantage. Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their opposites: companies can for a time keep the higher profits they reap from the superior performance and have to suffer the losses from a poor one.*

The explicit effect of COSI was to reduce regulatory lag and its associated incentive for achieving maximum operating efficiency. In the illustration of this effect which follows, we compare the incentives for efficiency under COSI with the incentives for efficiency facing a company which has a rate case every 5 months. In this comparison, we have made some simplifications in the regulatory process which do not significantly alter the effects we illustrate. Also, in our illustration, we assume that, because input price inflation exceeds the rate of productivity improvement, a firm faces continually eroding earnings if its electricity rates are held unchanged for any period of time. This scenario is consistent with the recent business history of the electric utility industry.

Exhibit I.1 illustrates the operation of COSI (in its 1975-78 form) over five quarters in which inflation adversely affected PNM's costs. The rate of return indicated is that being earned at the moment in time indicated. We begin at point A, following a COSI-induced rate increase, with PNM earning the allowed 13.5 percent rate of return. Immediately following the rate increase indicated at point A, the rate of return earned by PNM begins to fall, as its costs rise due to inflation. The company's costs rise because inflation is more rapid than the productivity advance achieved by the company. When point B is reached, it is time for another COSI adjustment. Rates are adjusted upward so that the instantaneous rate of return will be

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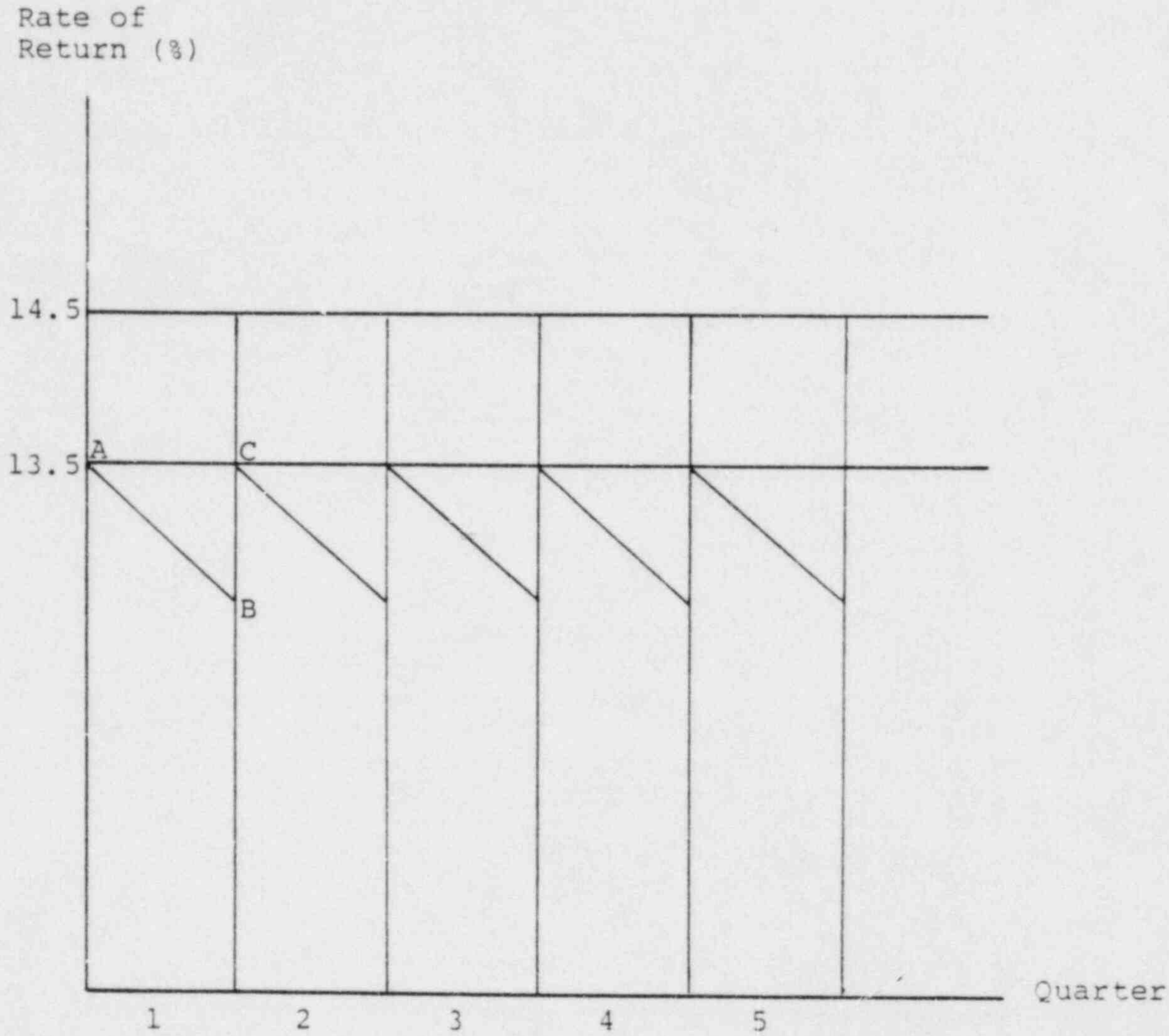
* Kahn, Alfred E. The Economics of Regulation, John Wiley & Sons, Inc. (New York: 1971). V. 2, p. 48.

Exhibit I.1

EFFECTS OF INFLATION UNDER COSI ON
PNM'S RATE OF RETURN ON EQUITY



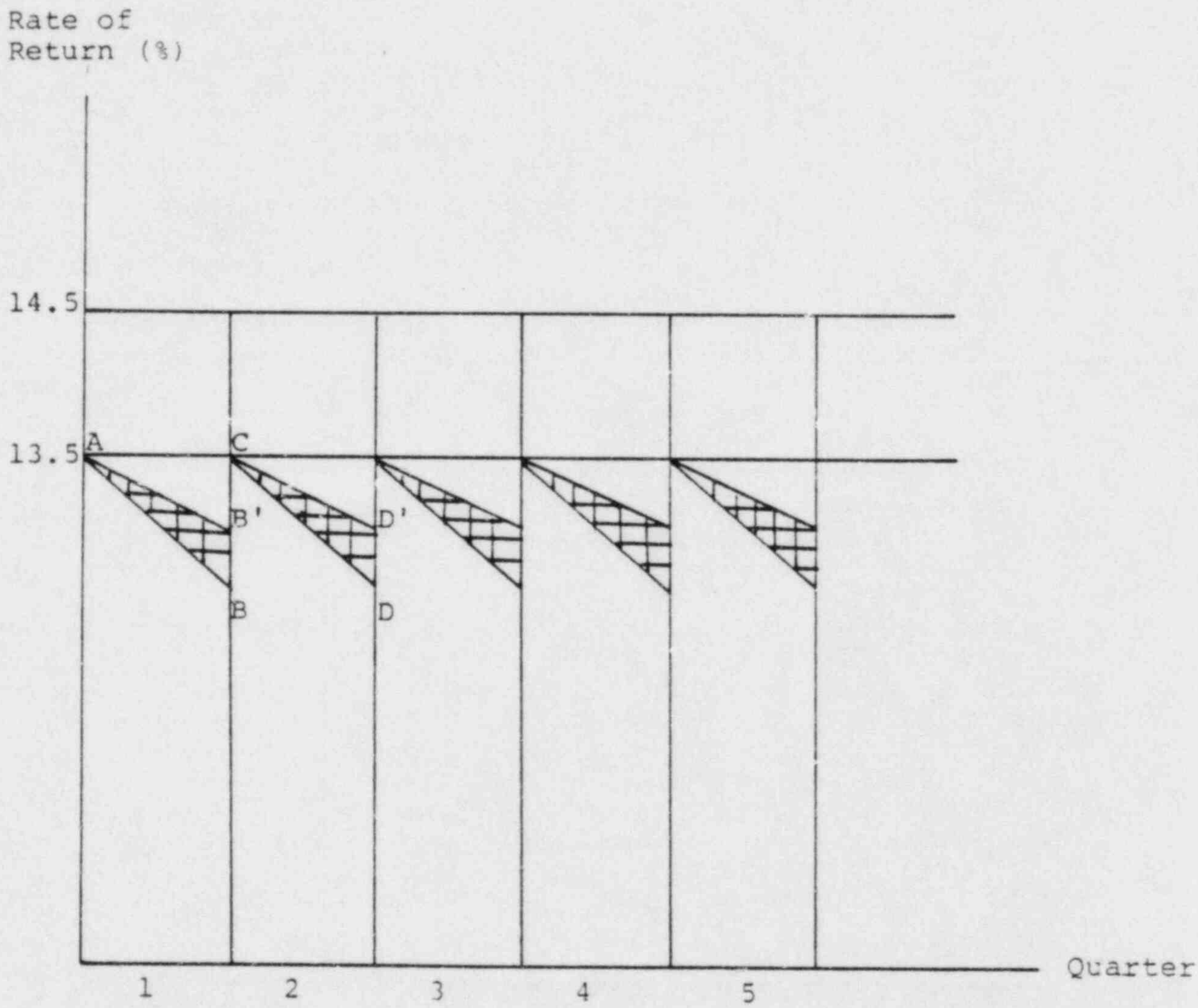
13.5 percent at point C, and the process begins again. In an inflationary environment then, the instantaneous rate of return on PNM's equity will follow the saw-tooth pattern illustrated in Exhibit I.1. Note that the average rate of return is below the lower band limit.

Two questions then arise. First, what incentives for efficient management could this procedure provide? This can be determined by looking at what happens to the rate of return on equity if some utility cost reductions are effected. Second, what are the benefits to PNM's stockholders (and indirectly to its managers through stock options and bonuses) if PNM reduces its costs below the cost levels used to illustrate Exhibit Exhibit I.1? The answer to this question will depend, to a certain degree, on the magnitude of the cost savings under consideration. The most likely, and best choice for the purposes of illustration, is that cost reductions occur in a steady stream of small reductions. If this steady stream of cost reductions is realized by PNM, its rate of return in the first quarter will be the one illustrated by the line AB' in Exhibit I.2. Rather than having its rate of return fall continuously during the first quarter from point A (i.e., 13.5 percent) to point B at the end of the first quarter, the rate of return will only fall from A to B', as indicated. The rate increase at the end of the first quarter under COSI with the cost savings (B' to C) will be smaller than the rate increase (B to C) that would occur without the cost savings. The process will repeat itself. The profit benefit from these cost reductions (and thus the incentive for undertaking them) is represented by the cross-hatched area between the rate of return that is realized with the cost reductions, and the rate of return that would have been realized had the cost reductions not been made. This illustration assumes that the firm's ability to enact cost reductions is not great enough to allow it to keep the price of electricity from rising in absolute terms, although productivity advances do reduce electricity price increases.

This profit incentive can be contrasted with the incentive that exists under traditional rate of return regulation. To do this, we have made three assumptions. First, the Commission sets rates so that the instantaneous rate of return at the time of the decision is 14 percent (the center of COSI's band). Second, in the absence of any

Exhibit I.2

EFFECT OF A SMALL STEADY STREAM OF COST REDUCTIONS UNDER COSI ON PNM'S RATE OF RETURN ON EQUITY



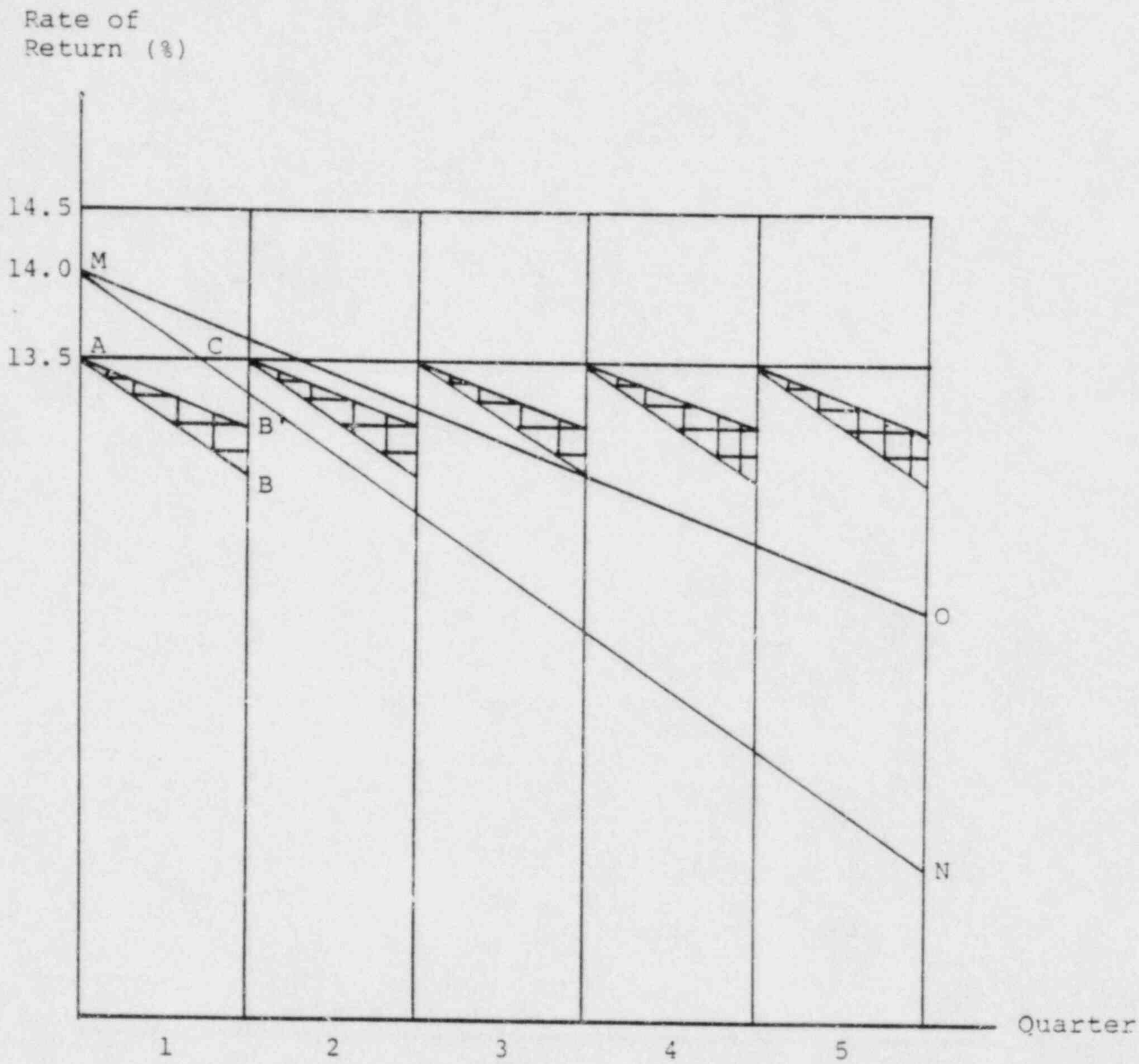
cost-saving improvements, inflation will cause PNM's costs to rise (and thus its return on equity to fall) at the same rate assumed under the COSI example above. Third, the same type of cost-saving investment is made under this example as in the previous example for COSI.

Exhibit I.3 illustrates these assumptions. Rather than starting at the bottom of the rate-of-return band (point A), the company is assumed to begin at point M (the 14 percent rate of return earned at that point in time). The decline in the rate of return over time from point M occurs at the same rate it did from point A (the line MN is parallel to lines AB, CD, etc). The rate of return at any point in time under traditional regulation can then be determined by finding its level on the line MN. Assuming the same rate of cost reductions as we assumed in the COSI case, the line MO represents the rate of return that would be earned if the cost reductions were achieved. The line MO is parallel to line AB' (the rate of return earned under COSI with cost savings). The benefit to PNM's stockholders from these cost reductions is represented by the area in the triangle MNO.

The stockholder benefits realized from enacting cost savings under traditional rate of return regulation versus a three-month COSI can be seen by comparing area MNO (traditional rate of return regulation with a 15-month regulatory lag) with the five cross-hatched areas which represent the profit benefit from cost reductions under COSI. It can easily be seen that the profit benefit to PNM's shareholders is significantly greater under traditional rate of return regulation than it is under COSI regulation (which has a three-month lag). This is so because, at the end of each quarter, COSI eliminates the profit benefit to PNM from the cost reductions by increasing the price by a smaller amount (B' to C) than it would have if the savings had not been effected (B to C). That is, COSI transfers the cost-reduction benefit to ratepayers after only three months and forces PNM to start its cost reduction program anew. Traditional rate of return regulation, with its longer period between rate adjustments, would allow the company to keep all the benefits for the entire time period between rate cases (15 months in this example). Of course, a greater incentive for cost reductions exists if a utility can earn and keep the fruits of its efforts for 15 months instead of only three under COSI.

Exhibit I.3

EFFECT OF COST SAVINGS UNDER TRADITIONAL REGULATION AND COSI ON PNM'S RATE OF RETURN ON EQUITY



This illustration of the incentive effects under traditional regulation would not be altered in substance if a future test year or some sort of attrition allowance were used. The results in Exhibit I.3 would be changed in a simple manner by the use of a future test year: the point at which the rate of return on line MO would equal 14 percent would no longer be at M; rather, the entire lime MO would be shifted up so that the 14 percent level would be reached at the mid-point of the future test year. Using a future test year treatment, the benefits from cost reductions would be identical to those under the traditional regulation depicted in Exhibit I.3, since the triangular area MNO would be the same over the 15-month period in both cases. Thus, while future test year treatment would affect the level of the rate of return earned, it would not affect the incremental return to the firm from cost-saving innovations.

In summary, the effect of COSI on incentives is equivalent to shortening the regulatory lag period to three months. Because the possibility of earning profits during the regulatory lag period is one of the major financial incentives for efficient management, COSI's effect on incentives is clearly negative.

Secondary Incentive Effects of COSI

In addition to shortening the regulatory lag period, COSI had two other negative impacts on efficiency incentives. First, because there was only a 10-day period for the review of PNM's accounting statements in the earlier version of COSI, there was effectively no Commission oversight of company expenditures. If the fear that a commission might disallow an expenditure retroactively (because the expenditure was deemed imprudent) is an incentive for keeping expenditures low, then the adoption of COSI must have had a highly negative impact upon efficiency incentives. With only 10 days to review the company's operating results, the Commission staff was effectively unable to monitor and allow or disallow (as prudency required) the company's expenditures, thus removing the incentive.

However, one effect of the 1978 modification of COSI was to lengthen the regulatory lag period substantially. Because the Commission had a significantly longer amount of time to analyze the company's operating statistics, it was more likely that any imprudent expenditures would be detected by Commission staff, thus increasing the efficiency incentives for PNM. This incentive was also probably strengthened by the fact that the COSI adjustment became the subject of an official hearing at which intervenors could present testimony and question company officials.

An additional negative incentive effect of COSI was isolated by Professor Myron Gordon in Case 1419. Gordon pointed out that making rate increases more predictable would ease the difficulty of financing new plant and equipment for PNM. He then expressed a concern that PNM might over-build as a result of easier access to the capital market.

The positive effects of COSI on management incentives are limited. One possible incentive for PNM's management created by COSI was the retention of the index itself. The Commission stated clearly at the time it adopted COSI that the index was an experiment and that PNM should view it as a privilege. Thus, COSI could be perceived as an efficiency incentive for PNM because the company needed to perform well if it wished to retain the privilege of using COSI. Whether or not the ability to retain such an index is a strong incentive or not depends upon what one believes about the Commission's ability to detect poor performance and their willingness to withdraw COSI in response to detected poor performance.

The rate of return on equity band under the early version of COSI provided another efficiency incentive. As long as PNM's return on equity fell within the 13.5 to 14.5 percent band, any increase in its profits resulting from efficiency measures would have accrued to the stockholders of PNM. Thus, as long as its efficiency measures did not cause PNM's return on equity to rise beyond 14.5 percent, PNM's efficiency incentives were identical to the incentives facing a firm whose profit is not regulated. Of course, this incentive is also present under traditional rate-of-return regulation; however, under COSI, the rules for determining the zone of reasonableness were better specified and the firm knew exactly the ceiling of return that would induce a reduction in its rates. Under traditional regulation, the firm may not know this "ceiling return." Thus, it may be encouraged to forego efficiency improvements if there is the risk of increasing earned return enough to induce a fallback in rates so that the rates produce lower earnings than before. This uncertainty was removed under COSI.

THE ADMINISTRATIVE COSTS OF COSI

One of the reasons COSI was originally adopted was that the time required to process a continual stream of rate cases coming before the Commission was overwhelming the Commission staff. While the use of COSI would not affect the need to have either traditional cost of capital or rate design testimony, it was hoped that COSI would greatly reduce the traditional "revenue requirements" testimony.

In his testimony in Case 1419, Robert Swartwout, Executive Director of the staff of the New Mexico Public Service Commission, addressed this administrative cost issue. Swartwout testified, for example, that by using COSI, two to four times more auditing effort went into the COSI mechanism that would go into a traditional annual rate case. Of course, since there would be no legal hearings unless the Commission found some objectionable cost items, legal costs (including the cost of expert witnesses) were reduced under COSI.

As revised in December 1978, the COSI adjustment was made less frequently, although hearings occurred every two or three months during the year. It was the opinion of the Commission staff* that the level of effort required by the later edition of COSI was still higher than what would have been required by traditional regulation (with annual

* Conversation with Commission personnel.

or less frequent rate cases). Thus, the administrative costs of COSI do not seem to have been significantly reduced. It is, of course, possible to reduce these costs beyond the level that the New Mexico Public Service Commission reduced them; however, to do so would essentially require that the Commission "bless" the company's submission without checking or analyzing it.

THE EFFECT OF COSI ON THE COST OF CAPITAL

Under traditional regulation, investors in privately owned utilities face several uncertainties. First, there is an uncertainty associated with regulatory lag: higher costs will generally be reflected in higher rates, although there may be a lag of up to several years before rates are raised to reflect the higher costs. Second, investors are always uncertain about whether or not public utility commissions will allow utilities to raise rates to recover all of their higher costs. That investors are concerned over this possibility is indicated by "commission ratings" undertaken by several investor research organizations. COSI was intended to modify these risks by making the regulatory lag period shorter and more certain, and by substantially reducing the risk that the Commissions in New Mexico would be able to hold rates below actual costs.

A number of attempts have been made to estimate the effect of COSI on PNM's cost of capital and, in conjunction, its effect on revenue requirements. The pertinent question in this case is: what is PNM's cost of capital (debt and equity) with COSI in place, and what would its cost of capital be, <u>ceteris paribus</u>, had COSI not been adopted in 1975? The best attempts to estimate the effect of COSI on the cost of capital came in Case 1419, which the Commission instituted to decide whether or not to retain and/or modify COSI. The Commission's decision, issued on December 29, 1978, provides an excellent summary of these attempts.

All of the economists and finance experts who have addressed this issue agree that COSI should affect PNM's cost of capital. The point of disagreement is an empirical one: can we measure the magnitude of COSI's impact? Several problems arise in attempting to make this determination. For example, because COSI affected only one company, it is entirely possible that other factors affecting the risk of that company could mask the effect of COSI upon the company's risk. In addition, during the period in which the experts were attempting to determine the impact of COSI, PNM issued an important dividend policy announcement. It is difficult to separate out the impact of this announcement from the impact of COSI.

Herman Roseman, an economist from National Economic Research Associates, testified on behalf of the Public Service Company of New Mexico in Case 1419. He estimated the impact of COSI on PNM's equity cost to be a reduction of one to two percentage points in this cost. His methodology included a comparison of PNM's market price with the market price of other utilities, and a comparison of PNM's price-earnings ratio with those of other companies.

Myron Gordon, a professor at the University of Toronto, was retained by the Commission in Case 1419 to estimate the impact of COSI on the cost of equity capital. He concluded that the adoption of COSI had not caused a perceptible reduction in PNM's cost of capital, even though his analytic results indicated that there had been a three-year net decrease of 0.84 percentage points in PNM's common equity capital costs relative to the average of five "comparable" companies. The analytic methodology used by Professor Gordon in Case 1419 differed from the methodology he had used in an earlier study dealing with a similar topic. In rebuttal testimony, Herman Roseman of N.E.R.A. stated that, "had Gordon used the methodology of the previous study, his methods and his data indicate that between February 1975 and February 1978 the cost of equity of PNM declined by 2.2 percentage points relative to the cost of equity of the comparison companies.*

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* Herman Roseman, 35 TR, 7-17.

The effect of COSI on debt capital costs should have been easier to determine. Specifically, with COSI, PNM should have been able to issue debt at a lower interest rate than other comparable utilities that did not have COSI. Unfortunately, PNM's witnesses in Case 1419 were unable to agree on this point. Mr. Frazier, employed by Paine, Webber, Jackson and Curtis, testified that "but for COSI, PNM would have lost its AA ratings.* Mr. Eugene Meyer, Vice President and Director of Kidder, Peabody and Company, also testifying on behalf of PNM, determined that, with COSI, PNM would have substantial savings on its debt, even relative to other AA listed companies. Herman Roseman, on the other hand, concluded that "one can't say for sure what the rating agencies would have done in different circumstances.**

Upon reviewing this testimony concerning the effect of COSI on the cost of debt and equity capital, the Commission concluded in "regards to COSI's impact upon preferred and long term debt, we are less confident of its past impact on reducing costs and even less confident of its future impact on these costs due to PNM's current financial parameters.+ With regard to equity costs, the Commission was more certain. It stated:

> The Commission feels that the weight of the evidence in the record supports the conclusion that COSI has been a primary factor in reducing PNM's cost of capital. In regard to equity savings, both Professor Gordon and Mr. Roseman's testimony and analysis have indicated a decrease in equity capital costs from 0.85% to above 2%.++

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* Frazier, 2TR 13-28.

** Roseman, 9 TR 1-10.

\+ Commission Decision in Case 1419, p. 36.

++ <u>Ibid</u>. In addition, the primary indicator of the COSI-induced decrease in PNM's equity capital costs was an increase in the market price of PNM's stock relative to other utilities at the time COSI was adopted in 1975. Thus, some of the capital cost "savings" created by COSI were passed on to PNM's stockholders at that time in the form of higher stock prices.

PNM continued to estimate the impact of COSI on its cost of capital and to submit its findings to the Commission in various COSI hearings between 1979 and 1982. PNM has estimated that the cumulative COSI-induced savings from 1975-1981 were $50 million in total savings, and a jurisdictional savings of $38.5 million. If, as Mr. Roseman testified for PNM in Case 1419, the COSI-induced cost of equity capital savings for PNM is two percentage points, then the total savings from 1978-81 were $87 million, and the jursidictional savings were $67 million. To place these values in perspective, PNM's total electric operating expenses in 1981 were $204.2 million.

DID COSI WORK?

We evaluated COSI from the perspectives of the company, its stockholders, the Commission, and the Commission staff. In summary, we found that from the perspectives of these groups, the cost of service index:

- Reduced equity capital costs by one to two percentage points
- Had little, if any, effect on PNM's debt costs (although the presence of COSI probably made it possible for PNM to raise capital when it would otherwise have been questionab e), and
- Did not substantially reduce the administrative burden on the Commission staff.

In evaluating COSI from the perspective of ratepayers in New Mexico, we found that the consumer reaction to COSI was almost uniformly negative in the later years of its experience. In general, ratepayers argued that, were it not for COSI, PNM would have received fewer rate increases and, on average, the rate increases would have been smaller (which may or may not be true). However, it is difficult to distinguish consumer objections to higher rates in general from objections to COSI in particular. In many cases, consumers attacked COSI because of its quarterly effect in their rates, even though these rates might well have increased in similar amounts had COSI not been in place. Exhibit I.4 lists the cost of service inde

Exhibit I.4

NEW MEXICO PUBLIC SERVICE COMMISSION COST OF SERVICE INDEX

Period Ending	Cents per kWh
June 1975	0.2688
September 1975	0.1997
December 1975	0.1974
March 1976	0.1974
June 1976	0.1974
September 1976	0.2209
December 1976	0.3003
March 1977	0.4942
June 1977	0.6898
September 1977	0.8853
March 1978	1.1212
June 1978	1.2329
September 1978	1.0730
December 1978	1.0882
December 1979	2.0940
December 1980	2.4081
December 1981	2.8081

SOURCE: Public Service Commission of New Mexico.

approved by the New Mexico Public Service Commission for the period 1975 through 1981. As shown in this exhibit, COSI-induced changes in PNM's kWh charges increased from 1.07¢/kWh in 1981. This increase of almost 200 percent was a contributing factor to consumer objections to COSI.

Some consumer criticism, however, was clearly directed at the lack of effective Commission oversight of PNM's expenditures. This criticism reached its peak late in 1981, and resulted in the initiation of legislative action and the enactment of House Bill 167 under which COSI is banned. The legislative action was initiated after a preliminary 1982 COSI surcharge had already gone into effect on January 1 (according to the 1978-1982 procedures).

The effect of COSI on PNM's productivity was the subject of much testimony and cross examination in Case 1419. Staff witness Rodney Stevenson, a Professor at the University of Wisconsin, testified that PNM had experienced a decrease in its total factor productivity since 1978: "the evidence indicates, on balance, a decline of productivity of PNM since the adoption of COSI."* The Attorney General of the State of New Mexico also retained a productivity expert, Jatinder Kumar. After using a partial factor productivity analysis on PNM, Kumar testified that PNM's productivity had decreased in more areas than it had increased since the adoption of COSI.

The company produced several productivity witnesses to rebut the testimony of these two witnesses. One witness for the company testified that PNM had experienced an increase in its total factor productivity since COSI was adopted; two other witnesses testifed that PNM had taken several actions to enhance its productivity.

The Commission concluded that "PNM's operations under COSI on the whole, had not conclusively resulted in the maintenance of and/or a net increase in the level of productivity.**

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* Testimony of R. Stevenson, Case 1419, p. 18. See Appendixes C and D for a discussion of different methodologies used to arrive at a total factor productivity index.

** Decision and Order in Case 1419, p. 46.

COSI's effect on PNM's earned return is somewhat more conclusive: while COSI may have increased the stability of PNM's earnings, it did not cause PNM's earnings to remain systematically within the "band of reasonableness." COSI was in place from 1975 through the end of 1981. In late 1978, the company's allowed rate of return was increased from 14 percent (the center of the band) to 15.5 percent. If COSI had been functioning perfectly, PNM would have expected to earn between 13.5 and 14.5 percent over the 1975-1978 period, and 15.5 percent from 1978-81. However, as shown in the table below, PNM did not earn either the lower bound (13.5 percent) during 1975-1978, or its target return of 15.5 percent from 1979-1981. The company's earnings, however, were relatively stable during this seven-year period.

What happened to PNM is exactly the result that is graphically presented in Exhibit I.1, i.e., PNM's actual return was systematically fluctuating between the lower-bound limit and a lower figure. This ratcheting was predictable if the expected rate of inflation was higher than PNM's expected rate of productivity increase, which was in fact the case throughout the seven-year period. As a result, PNM's average rate of return in each year was below the Commission's "target" rate of return of either 13.5 percent or 15.5 percent.

RETURN ON COMMON EQUITY[a] FOR
PUBLIC SERVICE COMPANY OF NEW MEXICO

Year	Return (Percent)
1975	11.7
1976	10.3
1977	11.6
1978	13.0
1979	13.6
1980	14.9
1981	14.7

NOTE: 1981 figure omits (from net operating income) a 90¢/share gain from liquidation of a subsidiary. With this gain included, the figure is 18.6%.

SOURCE: Standard & Poor's Stock Guide, 1975-1980; PNM officials provided data for 1981.

a. (Net operating income - preferred divident requirement) ÷ average common equity.

ALTERNATIVES TO COSI

There are a wide variety of alternatives to a pass-through mechanism such as COSI which would better retain efficiency incentives for management. In the sections below, we present five of these alternatives that would either increase the incentives for efficiency or allow the COSI to go into effect only during periods of high inflation when it is most needed.

1. Introduce a variable recovery cost of service index. Under this type of index, the portion of cost increases that a utility would be allowed to pass through to ratepayers would vary with the rate of inflation. For example, if the national rate of annual inflation were greater than seven percent, a utility would be allowed to pass through 100 percent of all cost increases (as measured by earnings below a minimum acceptable level). If the national inflation rate were six percent, 80 percent of all cost increases could be passed through; if it were five percent, 60 percent of all cost increases could be passed through, and so on as long as inflation remained above two percent per year. If the national rate were two percent or less, no automatic cost increases would be allowed. In this case, a utility's productivity growth should be sufficient to overcome a two percent inflation rate and allow it to keep total unit costs constant. The utility would recover the remainder of its higher costs through infrequent rate cases.

This proposal is somewhat similar to the Sliding Scale Plan that was applied by the District of Columbia Public Service Commission to the Potomac Electric Power Company (PEPCO) between 1925 and 1955. Under this program, a rate-of-return target was established as it was under COSI; however, changes in cost or productivity that caused the return to exceed the target triggered a rate adjustment that would transfer only 50 percent of the cost savings to ratepayers. If costs increased and PEPCO's return fell below the target, rates would be increased to restore PEPCO's return, but only after a variable period that depended on the extent of the return shortfall: the greater the shortfall, the shorter the period before adjustment.

2. Apply the cost of service index differently to different cost items. If FERC determines that a set of cost items is not controllable by management, changes in the cost of these items could be recovered through a

COSI-type mechanism. Cost items which are controllable, to a greater or lesser degree, could be covered by a modified COSI which passes through, for example, 80 percent of the cost increases for the moderately controllable items and 60 percent of the cost increases for the definitely controllable items. Again, periodic rate cases would allow the utility to recover the remainder of all proper cost increases.

3. <u>Create wider rate of return band</u>. To increase the efficiency incentives built into an index that contains a rate of return band such as COSI did in its first version, rate of return band within which no COSI adjustment occurs should be widened. The wider the band over which there is no adjustment, the greater the incentive for cost-reducing efforts. For example, if FERC determined that a utility's cost of capital was 14 percent, the rate of return band might be set from 13 to 15 percent.

4. <u>Introduce a COSI with a variable lag, where the lag depends on the national inflation rate</u>. Because a utility's need for protection from cost increases is greater in periods of rapid inflation, FERC might allow a COSI to operate with a four-month lag if the rate of inflation as measured by some national index (e.g., the producer price index) was greater than eight percent. If the inflation rate was between four and eight percent, adjustments to the COSI might be allowed only once each six months. Finally, if the rate of inflation was less than four percent, COSI-incuced rate adjustments might be allowed only once every year. If this alternative to the 1981 version of the New Mexico COSI were adopted, FERC would have to set up careful rules about the revision of the lag period in times of changing inflation rates. For example, the lag structure required if the inflation rate grew from seven to nine percent would have to be specified, since it might differ significantly from the lag structure that would be appropriate if the inflation rate fell from five percent to three percent. This alternative is superior to a fixed lag COSI in terms of providing incentives for efficient management to a utility, while protecting the utility's earnings from regulatory lag in the times of rapid inflation.

5. <u>Implement a conditional cost of service index</u>. The conditional cost of service index idea was developed principally by John W. Kendrick of George Washington

University.* A variety of formulations have been suggested for this index. Although these conditional cost of service index plans have major differences, they also have one common element. Namely, the degree of cost increases a firm is allowed to pass through is dependent on the productivity performance of the firm. If productivity is stagnant or declining, fewer cost increases are allowed in setting rates. If the firm's productivity increases rapidly, however, the firm is allowed to recover all of its cost increases and also retain an additional margin of return. There is an upper limit on the rate of return the firm is allowed to earn, regardless of how much productivity savings it can accomplish. The implementation of a conditional COSI program would differ from the New Mexico COSI, primarily in that the program's auditors would have to be trained in the methodology of measuring total factor productivity. The primary advantage of a conditional COSI is that it would increase incentives for efficiency above those in the New Mexico COSI by making the lower bound on the rate of return conditional on the firm's efficiency performance.

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* Kendrick, J. W. "Efficiency Incentives and Cost Factors in Public Utility Automatic Revenue Adjustment Clauses." Bell Journal of Economics, Spring 1975, pp. 229-313.

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IMAGE EVALUATION
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