POWERPLANT PRODUCTIVITY IMPROVEMENT STUDY

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Policy Analysis and Incentive Assessment

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EXECUTIVE SUMMARY

In the last decade, the U.S. electric utility industry has faced substantial challenges brought about by rapid developments on several fronts. Increased load growth uncertainty, inflation, tight capital markets, licensing and siting delays, and stringent environmental constraints were further complicated in 1974 by the OPEC oil embargo and steeply rising fuel prices. As a result of these pressures, increased attention has been given to the more efficient use of existing generating units as an economic alternative to new construction, and as a mechanism for near-term reductions in scarce fuel consumption.

In March, 1975, a Federal Interagency Task Group recommended a thorough analysis of the benefits of improved powerplant reliability in terms of reduced consumption of scarce fuels, reduced utility capital requirements, deferred additions of new capacity, and reduced rates to consumers of electricity (Reference A). The US Department of Energy has since encouraged increased efficiency in the use of scarce fuels in the electric utility industry under a broad range of programs. The potential for reducing oil consumption nationwide through improvements in the productivity (availability) of baseloaded units has been shown to be significant. It has been estimated (Reference B) that a 5 percentage point improvement in forced and planned outage rates of large coal and nuclear units could result in a net reduction in oil consumption of 54 million barrels per year by 1985 in the Northeast and East Central Regions alone. A substantial cost savings potential was also reported. In 1976, the Department of Energy (Federal Energy Administration) sponsored the development of a systematic methodology for the identification and analysis of candidate projects which a utility might undertake to improve baseload unit reliability (Reference C). This methodology also enabled the user to estimate a project's ef-

fect on the future performance of the unit. It was applied by Mechanics Research, Inc. at three utilities.

In order to demonstrate and further validate that methodology, and to encourage increased powerplant productivity in the state of Illinois, in 1977 the Department of Energy sponsored a cooperative study project with the Illinois Commerce Commission. Technical assistance was provided to the Commission by the Energy Resources Center, University of Illinois at Chicago Circle, and Trident Engineering Associates, Inc., at subcontractor. This study consists of the following major tasks.

- o Identification and documentation of current utility approaches to powerplant productivity in Illinois, based on a study of the four largest privately owned utilities in the state.
- o Application of the DOE developed methodology at Illinois Power Company Wood River 5 and Commonwealth Edison Company Quad Cities 1 and 2 units. A total of eight improvement projects were analyzed by Trident for their effect on unit performance.
- o Estimation of costs and benefits to the utility of the eight productivity improvement projects.
- o Comparison of current utility approaches to improvement of productivity with the DOE developed methodology to determine strengths and weaknesses of each.
- o Survey of historic productivity performance of powerplants in Illinois.
- o Analysis of current regulatory incentives and disincentives to improved powerplant productivity in Illinois and development of candidate regulatory incentive policies for consideration by the Illinois Commerce Commission.
- o Estimation of benefits to utilities and ratepayers in Illinois which would result from modest improvements in powerplant productivity in the state.

Objective of This Task

The objective of this task is to identify and analyze policy options which the Illinois Commerce Commission might adopt in order to promote improved powerplant productivity for existing units in Illinois. These policy options would generally involve either removing existing disincentives and/or adding direct incentives through the regulatory process. In view of the complexity of the issues which confront that objective, it is understood that this report will be essentially an exploratory, rather than definitive.

Approach

The approach followed in this task consisted of the following activities:

- o In-depth review of existing theoretical and empirical literature in the areas of powerplant reliability, regulated utility efficiency and performance incentives, and impacts of various regulatory mechanisms such as the Fuel Adjustment Clauses on productivity. Results of this literature search have been incorporated into an annotated bibliography as a part of the task report.
- o Contacts with other state public utility commissions known to be investigating or implementing productivity improvement incentive mechanisms.
- o Documentation and analysis of incentive mechanisms adopted or under consideration in other states.
- o Analysis of current regulatory practice in Illinois as it relates to powerplant productivity incentives and disincentives.
- o Identification of candidate incentive mechanisms for consideration by the Illinois Commerce Commission.
- o Analysis and evaluation of these candidates.

Key Findings and Conclusions

Because of the exploratory nature of this task, definitive results and recommendations could not be developed. However, the following observations are provided.

- o The current regulatory environment in Illinois is such that clear-cut statements about existing incentives and disincentives to the undertaking by utilities of productivity improvement projects can not be made. Normal regulatory lag, whether or not the allowed rate of return is being earned, and whether a project is expensed or capitalized, all affect the economic incentive structure in complex, case - dependent ways.
- o Because of the above, there is reason to believe that utilities generally respond to indirect rather than direct incentives when they undertake plant improvement projects. Under an indirect incentive, the utility usually cannot make a direct link between costs and benefits of the project and earnings. This arrangement is considered by the authors to be less desirable than one involving direct incentives, in which earnings are directly related to the net improvement as seen by consumers.
- o Although several state public utility commissions are currently experimenting with various incentive mechanisms directed at improving productivity, none of these has been in operation long enough to permit an empirical assessment of effectiveness. All such mechanisms brought to the attention of the Illinois study team appear to have the potential for improving powerplant performance in some specific area (such as capacity factor) at the cost of cost-effective improvements in other areas of performance. It should be made clear that this is a "theoretical" concern at this time and no empirical evidence is yet available which would provide a basis for a conclusion on the overall effectiveness of single measure incentives.
- o There appears to be little evidence at the present time that the single measure incentive mechanisms being implemented in other states will achieve the desired objective of improving performance in that measure. This is due entirely to the fact that most such mechanisms have been implemented fairly recently, and empirical data should become more abundant with time.
- o Currently, the most desirable incentive mechanism appears to be one which is direct, as discussed above, and which provides an incentive for the utility to undertake (and to search out opportunities for) productivity improvement projects in all areas. This would include such areas as availability, capacity factor, and heat rate. Although other elements of this project have confirmed that improvement in unit equivalent availability appears to be the most effective approach to the improvement of overall powerplant productivity, it should probably not be pursued in such a manner as to discourage cost-effective improvements in other areas.
- o The following specific mechanisms are suggested for consideration by the Illinois Commerce Commission:

A. Improve Information Flows Regarding Potential Productivity Improvements

The Commission could focus utility attention on productivity issues not only by publicly proclaiming their importance but also by facilitating the dispersal of information to utilities regarding possible productivity improvements such as technical R&D supported by the Department of Energy and trade associations such as EPRI.

B. Institution of Efficiency Incentives Tied to Rate of Return

A mechanism by which the allowed rate of return would be adjusted in accordance with overall productivity could be implemented with changes in the Public Utilities Act. Rate of return would be partially based on changes in a utility's performance as measured against its own historical performance or national averages. This would require consensus on the choice of an overall productivity measure which may constitute a substantial obstacle, but many of the potential adverse side effects of single measure incentives would be avoided.

C. Modification of the Fuel Adjustment Clause

Any fuel adjustment clause carries with it a potential for inefficient operation which could act as a disincentive to certain productivity improvement projects. Although no empirical data is available which support this concern, it may be possible to counter the disincentive effects. One mechanism for doing so is a Cost and Efficiency Adjustment clause which guarantees recovery of only a portion of increased costs (such as fuel costs). The balance of increased costs would have to be recovered through improved productivity.

Except for A, considerably more analysis appears to be needed to thoroughly evaluate these mechanisms. Substantial changes in regulation can only be achieved through legislation or formal hearings. Mechanisms B and C require further study before they can be subjected to this process.

I. INTRODUCTION

Background

In 1974, the Federal Energy Administration (FEA) led an interagency Task Group which investigated the then current status of powerplant productivity. Based on that study, it was determined that large coal-fired and nuclear generating units were operating below expectation. A subsequent study in 1975 by Mechanics Research, Inc. identified some underlying causes of lost productivity and defined possible corrective actions. A more comprehensive study was sponsored by FEA to develop analytic methods for the routine systematic analysis of cost and improved plant performance associated with plant improvement programs.

Simultaneously, General Electric's Center for Energy Systems conducted a study for FEA on the benefits of improved powerplant reliability and productivity. This analysis examined the effects of a hypothetical 5 percentage point improvement in planned and forced outage rates on utility fuel consumption, generation costs, and capacity expansion alternatives for Detroit Edison Company, the New England Power Pool, and the Northeast Utilities Company. For the Northeast and East Central Regions (representing approximately 25% of the US utility industry capacity) potential oil savings of 54 million BB^L per year, valued at approximately \$1 billion dollars per year, were reported.

In order to further validate the systematic methodology and encourage improved powerplant reliability and productivity in Illinois, the US Department of Energy sponsored a cooperative study with the Illinois Commerce Commission (ICC). Under the DOE/ICC program, eight candidate productivity improvement projects were selected and analyzed at Commonwealth Edison's Quad Cities units I and II, and Illinois Power's Wood River 5 unit.

This task consists of examining the current regulatory framework in Illinois and identifying any existing incentives or disincentives to the improvement of powerplant productivity. Based on a survey of literature and contacts with public utility commissions in other states, a list of candidate policy options to promote increased productivity is developed and analyzed in terms of applicability to Illinois. These analyses will be presented to the Illinois Commerce Commission for their consideration.

Overview of the Regulatory Process

Traditionally, questions of utility productivity or efficiency and regulatory incentives have not been at the forefront of state public utility commission priorities. This was partly due to the impressive advances made by the electric utility industry in the United States during the fifties and sixties as technological developments and economies of scale, combined with stable growth, resulted in declining charges to ratepayers. Given the performance of the industry during that period, few were inclined to ask whether further incentives were needed to achieve even greater efficiencies. There is increasing evidence, however, that past trends have leveled or possibly even peaked, and that any significant future gains in productivity will have to be pursued with great vigor.

The primary focus of this task is on regulatory policies which will essentially increase the efficiency of regulated electric utilities. More specifically, attention is concentrated on efficiencies to be brought about through the improvement of the reliability of existing powerplants. The overriding problem, of course, is to provide a mechanism by which the utility is encouraged to undertake cost-effective projects which improve plant reliability and availability. If reliability were the only performance criterion of interest to be

regulatory agency, any number of appropriate actions could be identified which would achieve that goal. Clearly it is not, and the major consideration in evaluating candidate incentives is whether the favoring of one or a few measures of performance will distort the firm's allocation of resources in such a way as to increase the net long-run cost of service to ratepayers.

There are several factors which may be responsible for the current level of performance of large nuclear and coal-fired powerplants. These include:

- o State-of-the-art technical problems involving hardware. These problems are responsible for lost productivity at a number of units in Illinois, but do not seem amenable to solution by regulatory action.
- o Cash flow problems. Especially during tight money market periods, utilities are forced to select projects subject to a relatively firm capital budget constraint. This can lead to the rejection or postponement of some projects which, although cost-effective, are not sufficiently so to compete with other projects for limited funds.
- o Regulatory disincentives. Fuel adjustment clauses and regulatory lag are examples of regulatory policies which could operate to discourage some cost-effective plant improvements.
- o Managerial problems. The rapidly changing environment in the electric utility industry requires innovative and aggressive responses by management. Institutional change, however, tends to evolve slowly.
- o Built-in hardware limitations. The performance of some units appears to be limited by original design with substantial commitments needed to effect improvements.
- o Environmental constraints. Most operating units in Illinois are influenced to some extent by compliance with various environmental regulations.

Any effort to address the upgrading of powerplant performance must consider that some or all of the above are operational. For the reasons stated, only recently have state public utility commissions begun to examine critically the productivity of regulated utilities, and to consider mechanisms for promoting improved performance. Few empirical studies in this area have been attempted and

the theoretical literature is sparse and often at an unusable level of abstraction. At best, the available literature serves as a general guide by providing a model of the regulated firm.

It is useful to distinguish in this report between what may be called direct and indirect incentives. By a direct incentive is meant one which operates to produce a clear economic benefit to the utility, the magnitude of which is directly determined by the project under consideration. For example, if a utility undertakes a capitalized plant improvement project which reduces annual fuel costs by more than the annual(-ized) cost of the project, this could result directly in improved earnings, the amount of which would be determined by the economics of the project.

An indirect incentive is one which operates through some intermediate path to yield benefits which are somewhat remotely related to the apparent economics of the project. For example, a maintenance project which is expensed might eventually produce a net reduction in revenue requirements but need not directly increase earnings. It could, however, lead to greater kilowatt-hour sales and revenues, which in turn would result in increased earnings. But the earnings improvement would depend on customers' price elasticities of demand, the company's incremental production costs, and numerous other factors. It would be difficult at best for a utility to estimate the ultimate impact on earnings of such a project. Another indirect consequence of such a project would be the less tangible but certainly real benefit which would stem from maintaining relatively lower rates as viewed by consumers and regulatory agencies.

Clearly, direct and indirect incentives are not mutually exclusive. It is probable that any project which produces direct benefits will carry with it some indirect ones as well.

A significant obstacle to the analysis of incentives and disincentives is the current regulatory framework is that neither is likely to be completely effective, with the exception of outright prohibitions and mandates. Thus, even if a disincentive exists, some improvement projects are likely to be undertaken. Likewise, even if a strong economic incentive exists, it may not always be exploited. The question of how effective an incentive (disincentive) is in practice is a difficult empirical question which could not be addressed quantitatively within the resource constraints of this study.

The task of identifying candidate incentive mechanisms for the improvement of powerplant productivity is complicated by the need to ensure that unintentional adverse side effects do not accompany the improvements. For example, it is often assumed that an incentive is satisfactory if the benefits due to improved productivity exceed the total costs, including any costs the incentive itself might entail. It is simply untrue that a utility should undertake (or be encouraged to undertake) every project for which benefits exceed costs. Consider a utility with two candidate projects, one involving an improvement in the transmission system and another an improvement in the generation system. If the projects each cost \$1 million, but benefits are \$4 million for the transmission project and \$3 million for the generation project, the transmission project should be undertaken first. If an incentive, however, is provided to encourage undertaking the generation project to the exclusion of the transmission project, customers will pay higher rates. This type of problem could arise whenever incentives are tied to specific performance measures, such as availability or capacity factor.

If utilities had unlimited funds available, then it would be reasonable to encourage that all cost-effective projects be undertaken. But utilities are similar to individuals and operate with relatively fixed capital budgets and

therefore must select the most attractive projects from their list of cost-effective projects. No financial institution would provide funds sufficient for a utility or an individual to undertake all cost-effective projects.

In order for a state public utility commission to provide an incentive for one type of cost-effective project, such as one which will improve capacity factor, it must determine that this will not cause other performance measures to suffer. Operationally, this means that it is insufficient to know that a particular project has benefits which exceed costs. What must be known is whether that project will produce more customer benefits per dollar expended than all other competing projects. This process is known as "capital budgeting" and is followed routinely by most business enterprises including regulated utilities. If an incentive structure is designed to favor improvements in a particular performance measure without consideration of effect on other performance measures, allocative distortions may result which effectively increase rates to consumers.

Clearly, not all single performance measure incentive mechanisms are ill-conceived and detrimental to ratepayers. At the same time, however, a state public utility commission is generally required to secure for the ratepayers the lowest possible rates consistent with other objectives. Concentration on a single measure of performance without some indication of the net effect on rates would probably not fulfill the obligations of that charter.

Approach

The general approach to this task consisted of the following activities.

- o Literature Survey. A through search was made of published papers, books, and articles dealing with regulated utility efficiency and performance incentives, and the impacts of various regulatory mechanisms, such as fuel adjustment clauses, on performance.

Relevant materials discovered as a result of this survey are listed in an annotated bibliography in an appendix to this report.

- o Contacts with Other State Public Utility Commissions. All state commissions known to be investigating or implementing productivity improvement incentive mechanisms were contacted by telephone or visited. In some cases staff analyses were obtained and are referenced in this report.
- o Development of Candidate Incentives. From the literature survey and other state commissions, a list of candidate incentive mechanisms was compiled.
- o Analysis of Current Regulatory Practice in Illinois. Current regulatory practice in Illinois as it relates to powerplant productivity incentives and disincentives was examined. Included were issues such as typical regulatory lag, effects of CWIP and AFDC, and the Fuel Adjustment Clauses.
- o Analysis of Candidate Incentives. Based on the results of the above activities, the list of candidate incentive mechanisms was analyzed and evaluated in terms of applicability to Illinois and overall effect on utility performance.
- o Identification of Near Term Options for Illinois. Options which are open to the Illinois Commerce Commission without major legislative changes were identified and discussed.

As suggested earlier, the approach adopted was directed at the development of a preliminary report on the current state of the use of incentive mechanisms for the improvement of powerplant productivity. It appears clear that considerably more experimentation and analysis will be required to support a recommendation for any substantive regulatory incentive mechanism. This report was intended to provide a background for such an undertaking.

II. CURRENT PRACTICE IN ILLINOIS

A. Introduction

Utility projects which are designed to improve the productivity of existing generating units currently come to the attention of the Illinois Commerce Commission only if they are very large. Although there now exists no formal mechanism for monitoring the productivity of utilities or for encouraging improvements in existing productivity, discussions with ICC staff and Commonwealth Edison and Illinois Power Company personnel have revealed specific incentives and disincentives for productivity improvements.

The most frequently mentioned factor for encouraging productivity improvement is the normal regulatory lag (currently it takes approximately 11 months from a filing to any eventual rate change). If regulation were instantaneous, so that rates were immediately adjusted to maintain the allowed rate of return whenever there were changes in demand or cost conditions, then utilities would have little incentive to improve productivity of existing plant. An unregulated, profit-maximizing firm would be expected to undertake any productivity improvement project which has an internal benefit cost ratio in excess of 1. For a utility, this would mean any project which would reduce its net revenue requirements (i.e., benefits > cost). But with no regulatory lag, the reduced revenue requirements (for expensed projects) would be instantly reflected in lower rates so that the utility's total profit would be unaffected by the improvement in productivity. Therefore the lag between the time an improvement is effected and the time at which the rate schedule is revised to reflect the lower revenue requirement allows the utility to earn a greater profit which could serve as an incentive to such innovation.

The above discussion assumes that the utility's rates are set so as to allow a "fair" rate of return. However, rapid increases in input prices (fuel, labor and capital) have resulted in many utilities earning less than the allowed rate, particularly since the early 1970's. As long as the actual rate of return is less than that authorized, the utility has essentially the same incentive to improve its productivity as would a firm which does not face an upper limit on its rate of return. In this situation it is expected that the social benefit-cost ratios of potential productivity improvements should be the same as the internal calculations made by the firm. That is, any project which is attractive from the ratepayer's perspective is also attractive to the utility.

Rapid increases in utility fuel prices have led to widespread adoption of fuel adjustment clauses (FAC) by many state regulatory commissions. The rationales for these plans are that fuel costs are volatile, outside the control of the utility, and contribute a major portion of utility expense. FAC provides an automatic adjustment in rates due to increased fuel costs and thus to some extent shifts the risk of future price fluctuations from the utility's stockholders to its customers. The FAC's currently in use in Illinois result in a surcharge per kwh to recover the cost increase per kwh compared to a base period, and provide for adjustments in cost recovery to account for technical efficiency and the heat rates of different fuels.

Optimal allocation, and therefore least cost production, requires that a firm adjust its production process in response to changes in factor prices. Least cost equilibrium requires that each factor of production be used in such a proportion that the revenue produced by the last unit employed be just sufficient to cover the unit cost of that factor. If the technology of production is

constant and the relative prices of factors change, optimal allocation requires that the firm alter its factor proportions. By guaranteeing the firm an automatic rate increase each time one component of its cost increases, the firm is partially insulated from the market signals necessary for making optimal allocational choices. Thus the FAC can create disincentives, not just to productivity improvements, but to efficient operation in general.

An objection which could be raised to the criticism of the efficiency aspects of FAC is that in the short run utilities cannot easily substitute factors in response to changes in relative prices because factor proportions are fixed by technological constraints. In other words, if fuel prices rise relative to labor prices, one would expect some substitution of labor for fuel. This might occur through increased maintenance on more efficient generating units for example. But opportunities are limited. If this is true, it holds only for the short run. Several authors have documented long run substitutions between capital and labor as well as between different types of capital, all in response to changes in the relative price of the factors Boyes (1976); Courville (1974); Petersen (1975); Spann (1974). The longer the FAC is in effect, the greater would be the social cost of the distortion in factor proportions.

It also should be noted that the Illinois FAC does contain provisions which may tend to reduce the disincentive effects. These include a lag between when costs are incurred and collected, and an inventory averaging mechanism which keeps higher per unit costs from being immediately collected. At the present time there is no empirical evidence which unambiguously resolves the question of a net FAC effect on incentives.

B. Analysis

It is instructive to examine the incentive and disincentive effects for capitalized and expensed projects under a number of different assumptions. In this section, the following matrix will be used as a framework for analysis.

<u>Case</u>	<u>Effects</u>	
	<u>Without Lag</u>	<u>With Lag</u>
<u>Capitalized Project:</u>		
Utility Earns Allowed Rate of Return	IA	IB
Utility Does Not Earn Allowed Rate of Return	IIA	IIB
<u>Expensed Project:</u>		
Utility Earns Allowed Rate of Return	IIIA	IIIB
Utility Does Not Earn Allowed Rate of Return	IVA	IVB

Some simplifying assumptions were made in this analysis. These are summarized below:

- (1) No changes other than those brought about by the project are assumed.
- (2) Cash flow is assumed positive in all periods, including the year of implementation of the project. In other words, in any year, cash inflow from a project exceeds or equals cash outflow for the project.
- (3) Allowance for Funds used During Construction (AFDC) and Construction Work in Progress (CWIP) are not considered.

Technically, the incentive and disincentive effects should be examined in terms of discounted cash flows and present values. This would complicate the

discussion, however, and at the same time provide little additional insight. Most of the effects of interest occur during the first year with lag, and without lag, do not change from year to year.

Case IA - Capitalized Project, AROR Earned, Without Lag

Since no regulatory lag is assumed, the capitalized project is immediately included in the rate base and the utility earns its allowed rate of return on the project. The maximum direct economic incentive in this case is equal to the return on the addition to the rate base. The effect of the project on revenue requirements is:

$$\Delta RR = \Delta C_{o\&m} - (C_p) \times AROR$$

where

ΔRR = Revenue Requirements reduction

$\Delta C_{o\&m}$ = Reduced O&M expenditures due to the project

C_p = Project capitalized cost included in rate base

AROR = Allowed Rate of Return

The absence of regulatory lag also means that revenue requirements are immediately adjusted to reflect changes in O&M expenses and earnings brought about by the project. It may be observed that even if the utility follows the rule that $\Delta RR > (C_p) \times AROR$, which ensures a direct net benefit to consumers, there is no direct relationship between the magnitude of the incentive and the magnitude of the benefit. To illustrate this, consider a project which is capitalized at \$1,000 and earns an allowed rate of return of 10%. The direct incentive to the utility is set at \$100, whether the reduced O&M expenditures equal \$100 or \$5,000. In the first case, consumers see no benefits, whereas in the second case, they see benefits of \$4,900.

This situation arises frequently as utilities analyze projects. As a rule, when comparing alternative projects to achieve a specific objective, utilities will select that project which minimizes revenue requirements, thereby ensuring maximum consumer benefits. The technique can also be applied to the analysis of a single plant improvement project provided that the utility has a mechanism for translating the improved performance brought about by the project into revenue requirements effects. It should be pointed out, however, that the use of revenue requirements in this way constitutes an indirect rather than direct economic incentive to the utility. Reductions in revenue requirements cannot be easily translated into improvements in earnings, and in fact, a \$1,000 reduction in revenue requirements could have widely differing earnings impacts for different projects.

Case IB - Capitalized Project, AROR Earned, With Lag

The effects for this case are similar to those for Case IA without lag. Here, it is assumed that the utility will be able to continue earning its allowed rate of return on rate base even after the project has been included. Between the time that the project is implemented and the next rate case, the utility will be able to exceed its allowed rate of return. Because positive cash flows were assumed, the net effect of the project is to reduce revenue requirements while maintaining revenues. It is not possible to definitively determine whether a direct economic incentive exists for this case because even though the utility earns in excess of the allowed rate of return on its rate base, that rate base does not yet include the project.

Assuming a 12 month lag, the magnitude of the direct economic incentive is given by:

$$\Delta RR' = \Delta C_{o\&m} + C_{pl}$$

where

$\Delta RR'$ = Difference between actual revenues, and revenue requirements which include the project for 12 month lag.

$\Delta C_{o\&m}$ = Reduced O&M costs

C_{pl} = Actual cash outflow due to the project in the first twelve months.

From Case IA (without lag), it was determined that the direct economic incentive is equal to the return on the addition of the project to the rate base, or:

$$\text{Incentive (without lag)} = (C_p) \times \text{AROR}$$

It is not immediately clear whether the incentive is greater with or without regulatory lag. Specifically, the question is under what conditions does the following inequality hold:

$$(C_p) \times \text{AROR} > \Delta C_{o\&m} + C_{pl}$$

Since the inequality may be true for some projects and not for others, it appears that for the assumptions used, regulatory lag does not automatically result in a direct economic incentive for a utility to undertake a project. Moreover, if the first year net cash flow is negative (i.e., first year costs exceed first year benefits) with lag, a direct economic disincentive may exist as given by:

$$\text{Disincentive (with lag)} = C_{pl} - \Delta C_{o\&m}$$

It is probably not unusual for projects to produce negative first year cash flows. Of course this disincentive would be offset by future earnings produced by the eventual inclusion of the project's capitalized cost in the rate base, and by the various indirect benefits to the utility.

Thus far, the above discussion has been limited to the twelve month period between implementation of the project and the next rate case, at which time the project would be included in the rate base. Since it was assumed that the utility would be able to earn its allowed rate of return, all of the future earnings resulting from inclusion of the project in the rate base would constitute a direct economic incentive, offset by any disincentive effects produced by the lag.

Case IIA - Capitalized Project, AROR Not Earned, Without Lag

When the utility is not earning its allowed rate of return, the direct economic incentive is:

$$\Delta RR = \Delta C_{o\&m} - (C_p) \times ROR$$

where

ΔRR = Revenue requirements reduction

$\Delta C_{o\&m}$ = Reduction in O&M costs due to the project

C_p = Project capitalized cost included in rate base

ROR = Rate of return actually achieved

Since the implementation of the project is assumed to reduce revenue requirements, it can potentially improve the utility's ability to earn the allowed rate of return. Thus, the rate of return actually achieved may be higher than it would have been had the project not been undertaken. This effect, however, is likely to border on insignificance even for the largest projects.

In general, since the rate of return actually earned is assumed to be less than the allowed rate of return, the direct economic incentive to the utility for this case is less than for Case IA, in which the allowed rate of return is achieved.

Case IIB - Capitalized Project, AROR Not Earned, With Lag

During the first year, the effect with lag is identical to Case IA, where the utility earns the allowed rate of return. That is,

$$\Delta RR' = \Delta C_{o\&m} + C_{pl}$$

where

$\Delta RR'$ = Difference between actual revenues, and revenue requirements which include the project for 12 month lag.

$\Delta C_{o\&m}$ = Reduced O&M costs

C_{pl} = Actual cash outflow due to the project in the first twelve months

Thus, the first year incentive is the same whether the utility is earning its allowed rate of return or not. In subsequent years, the magnitude of the incentive is:

$$\text{Incentive} = \Delta C_{o\&m} - (C_p) \times \text{AROR}$$

In comparing this to Case IB, in which the allowed rate of return is achieved, it can be seen that the incentive is reduced from that case by an amount equal to:

$$\text{Additional incentive when AROR is earned} = C_p (\text{AROR} - \text{ROR})$$

To determine whether lag improves the direct incentives when the allowed rate of return is not earned, the following inequality must be tested:

$$(C_p) \times \text{ROR} > \Delta C_{o\&m} + C_{pl}$$

As was true under Case IB, this inequality may be true for some projects and not for others. Thus, for the assumptions used, regulatory lag does not automatically result in a direct economic incentive for a utility to undertake a project, regardless of whether it is earning its allowed rate of return!

If the first year net cash flow is negative in this case, a direct economic disincentive may exist as given by:

$$\text{Disincentive} = C_{pl} - \Delta C_{o\&m}$$

It should be emphasized that all of the above applies only to the first twelve months (i.e., during the period of lag). In subsequent years, the project will be included in the rate base and will earn some return, which produces additional incentives. Clearly, the lower the actual rate of return achieved, the lower the total incentive. Of the four cases examined for capitalized projects, this appears to be the worst in terms of lowest potential incentive and highest potential disincentive.

Case IIIA - Expensed Project, AROR Earned, Without Lag

The effects in this case are readily observed. A project is undertaken which results in a net reduction in O&M costs. Without lag, revenue requirements are immediately adjusted downward. No direct incentive exists. Indirectly, a reduction in revenue requirements will benefit both the utility and the consumers as mentioned previously. Direct benefits to consumers, of course, are equal to the reduction in revenue requirements.

Case IIIB - Expensed Project, AROR Earned, With Lag

Since the utility is earning its allowed rate of return, a project which results in a net reduction in O&M costs will reduce revenue requirements but leave revenues unaffected. A direct economic incentive exists which is equal to the amount by which revenue requirements are reduced. If lag is assumed to be

twelve months, this will be a one-time incentive. After the next rate case, revenue requirements will be adjusted downward and only indirect incentives will remain.

Case IVA - Expensed Project, AROR Not Earned, Without Lag

This case is identical to Case IIIA in which the allowed rate of return is earned. No direct incentive exists.

Case IVB - Expensed Project, AROR Not Earned, With Lag

This case is identical to Case IIIB in which the allowed rate of return is earned. The direct incentive is not dependent upon whether the allowed rate of return is actually achieved.

C. Observations

From the foregoing, it is clear that considerable emphasis has been placed on direct, rather than indirect incentives. This results not so much from a belief in the inherent superiority of direct incentives as from the analytical intractability of those which are indirect. Yet, there is little question that utilities respond routinely to indirect incentives. In Illinois, the Public Utilities Act literally mandates that utilities base decisions on the objective of reducing revenue requirements, which means a reliance almost exclusively on indirect incentives.

The direct incentives considered certainly do not permit much generalization. As the situation stands, the direct incentive/disincentive structure is both complex and very project dependent. For capitalized projects, regulatory lag appears to produce ambiguous results, with the potential for economic disincentives. This finding runs counter to conventional wisdom on the incentive effects of lag and should be subjected to a more penetrating analysis.

CWIP and AFDC can provide some relief but are usually not used for smaller projects. In Illinois, a formal rate case filing is required to obtain permission to apply CWIP to a project. Cash flow considerations can be particularly important during inflationary periods with a one year lag on rate cases, and it is possible that a project with a negative first year cash flow would be untenable, even though flows in future years would be positive.

Although utilities have demonstrated the workability of the indirect incentive approach, it is possible both ratepayer and utility would benefit from a mechanism which directly rewarded the utility for innovative projects which results in direct benefits to customers. Ideally, such a mechanism would reward the utility in direct proportion to the benefits received by customers. This

would eliminate any allocational distortions and encourage improvements in all performance measures, including powerplant reliability, on the basis of net benefits to ratepayers. The following section of this report explores some candidates with this view.

III. SURVEY OF EXISTING INCENTIVES

This section is based on a preliminary survey of state public utility commissions which were known to be investigating or implementing incentive/disincentive mechanisms for improved productivity. In order to avoid semantic confusion, it is assumed in this report that an incentive to improved productivity is the same as a disincentive to poor or reduced productivity. A utility which is rewarded for improved productivity is automatically penalized for poor productivity since it is denied the reward.

The most general definition of productivity is the efficiency with which a firm utilizes inputs (labor, fuel, capital) to produce its output. Since the value of inputs may be expressed in dollars, the most productive firm will utilize the lowest cost combination of inputs per unit of output. Much of the current PUC activity in the area of productivity improvement incentives does not use such a definition, however. Instead, the focus is usually on some component of productivity as defined above, such as availability, capacity factor, or heat rate. All other things the same, an improvement in any of these components will result in an improvement in overall productivity, and this appears to be the justification for concentrating on the components. As indicated elsewhere in this report, it cannot always be assumed that all other things will be the same when the utility's resources are tilted through an incentive mechanism toward some specific component of overall productivity.

Connecticut

Within the last year the Connecticut Public Utilities Control Authority has taken two actions which affect incentives for powerplant productivity. On October

25, 1977 it issued two orders (Dockets No. 77-0319 and 77-0320) which established a target capacity factor of 68.8% for all nuclear units for purposes of computing reimbursement under the fuel adjustment clause (FAC). The FAC is scaled so that for an average capacity factor in excess of 68.8% for nuclear units, the firm is able to recover more than its actual fuel costs, while a capacity factor below the target forces the firm to absorb some portion of its fuel costs. The value of 68.8% was set forth after considering the historical capacity factors of existing units and the expected improvements in capacity factor as the newer units mature.

Another Authority order on the fuel adjustment clause has incentive implications. In a generic case decided on February 10, 1977 (Docket No. 76-0307) regarding rate adjustment procedures, the Authority modified the then existing FAC by introducing a variable heat rate into the clause. Under the previous provisions which assumed a fixed heat rate a utility increased its potential by adding more efficient plants to the system or by operating existing plants more efficiently. Under the new FAC, this incentive to efficient production is removed by reducing cost recovery each time an improvement in the heat rate lowers fuel costs. The motivation for the change was not, of course, to reduce incentives to efficiency but to compel utilities to pass on the gains of efficiency to its customers. Nevertheless, the impact which the change has on the incentive structure is adverse.

Michigan System Availability Incentive and Expense Indexing Procedures

In April 1977 the Michigan Public Service Commission issued an order (U-5108) regarding a Detroit Edison case which instituted a variable rate of return tied

to average annual system availability* via the following schedule:

Annual Average System Availability	Equity Return Incentive Adjustment
0-70%	-.25%
70.1-80%	-0%
80.1-85%	+.25%
85.1-100%	+.50%

The Staff stated that the "ideal" availability of a unit would be approximately 85% (allowing for planned maintenance need clarification outage hours). The incentive was intended to lower overall rates in the short run by reducing fuel and purchased power costs. In the long run it was argued that higher availability would decrease costs by reducing reserve requirements.

In July 1978 the Commission extended the availability incentive to Consumers Power Company and also instituted an operations and maintenance expenditure indexing scheme Order. The latter makes provision for "...automatic annual changes in the portion of the Applicant's rates attributable to certain operation and maintenance expenditures in accordance with changes in the National Consumer Price Index." (p. 114). The indexed portion of operation and maintenance expenditures are primarily administrative and general expenses since fuel, purchased power, and production maintenance expense were excluded from the indexing system. The rationale of the plan is to impose some competitive pressures on the firms by comparing their performance with that of the economy as a whole.

"By making the increase contingent on retail cost changes in the economy rather than utility incurred costs, management would be subjected to outside cost pressures. Thus it would necessarily have

* ECAR definition:
$$\frac{\text{System Available Hours}}{\text{Period Hours}}$$

to perform as well as the average of numerous other businesses as recognized by CPI or its stockholders would suffer a reduction in earnings. If management through cost control efforts could contain the...expenses such as to outperform the Consumer Price Index, then the stockholders would enjoy an increase in earnings. In this manner then, the proposal would act to reward efficiency and to punish inefficiency as would occur in a competitive market.' " (Ibid.)

Comments

The availability incentive plan is innovative and has attracted the interest of other state regulatory commissions. However, two aspects of the program deserve critical scrutiny. First, it is not clear that a target of approximately 85% availability is an appropriate "ideal". In the short run with existing plants, the optimal level of availability is that such that the additional cost of increasing availability further would exceed the additional benefits. The short run benefits of improved availability would be the avoidance of higher cost fuel or purchased power while the costs of improved availability would be reckoned in terms of expenditures on maintenance and other productivity improvements. In 1975 Detroit Edison conducted an internal cost-effectiveness study of availability improvements and the results are presented in Figure 2. Note that the availability level at which total cost is minimized is at 79%. It is possible that this is no longer an accurate estimate. The optimal availability level could have increased due to either technological changes, which would have shifted the maintenance cost curve rightward, or due to increases in the cost of purchased power. However, the Commission orders establishing the availability incentive do not document what the optimal level should be although the Staff appears to be mindful of this type of trade-off.

Furthermore, even if an optimal target level of availability were defined it is uncertain that the availability incentive would encourage achieving it.

**COST BENEFIT ANALYSIS of AVAILABILITY LEVELS
for DETROIT EDISON, NOVEMBER 1975**

Fig. 2

SOURCE: FEA, Electric Utility Design Proposals
February 1977, PB-272 266, p.205

The actual cost to consumers of passing through higher maintenance expenses may be greater than the amount of those expenses. This would occur if the benefits from spending those maintenance dollars elsewhere were greater than benefits from the increased maintenance. This is not to say that commissions will give carte blanche for all expenses which are somehow related to improvements in availability. It does suggest, however, that it will be generally impossible for a commission to second guess every expense allocation of a firm without completely supplanting the management function.

A second aspect of the availability plan relates to its long run impact on capacity expansion and reserve requirements. Given the existing plant sizes and generation mix, improving average system availability will decrease the need for future capacity and lower the reserves required to maintain a given level of reliability: "Over the long run, sustained high availability reduces the reserve requirements, which also reduces customer bills". (Case No. U-5108, p. 55). There is an additional dimension to the long run issue which is not addressed in the Commission orders. That is, what is the optimal tradeoff between a high initial cost of a more reliable (in an availability sense) generating unit and a less expensive one which will have lower expected availability over its useable life? Does the availability incentive encourage the firm to move toward this optimal point? There appears to be nothing in the Commission documentation which suggests an answer to these questions.

New Mexico Cost of Service Indexing Plan

On April 22, 1975 the New Mexico State Corporation Commission instituted an automatic cost of service indexing plan for the Public Service Company of New Mexico (Case no. 1196). The firm's rates are adjusted quarterly to maintain its

rate of return to equity within a 13.5 per cent to 14.5 per cent range. If any of the utility's costs increased, or decreases, so that the rate of return is outside the band, rates are adjusted without a rate hearing. A hearing is necessary only to change the target rate of return.

The New Mexico Commission felt compelled to institute some type of system because rapid inflation in input prices, demand growth, and environmental costs were causing frequent rate increase requests. Because of lags in the hearing process, the firm's revenue increases were insufficient to allow it to recover cost increases which were outside its control. By automatically revising rates quarterly, the Commission hoped to decrease the cost of the regulatory process while improving the firm's ability to raise capital. To the extent that these factors were previously providing disincentives to productivity improvements, such an indexing plan. Could be viewed as an incentive mechanism.

Comments

The plan has no provision for productivity change and would appear to create disincentives for productivity improvement in that the firm is guaranteed an approximately stable rate of return regardless of cost increases. The Commission responded to this concern in the original order (p. 29) by noting that since the firm is guaranteed a range rather than a specific rate of return, there still remains an incentive for efficiency in that the firm could raise its return to 14.5 per cent by cutting costs. Further, the three month delay between quarterly revisions was viewed as an incentive. However, recent conversations with staff of the New Mexico Commission revealed dissatisfaction with the plan, largely because of the incentive effects. The scheme has been in effect for over three years and is currently being reconsidered.

North Carolina Plant Performance Review Procedure

On March 9, 1978 the North Carolina Utilities Commission instituted a plant performance review procedure in conjunction with rate increase requests from three North Carolina Utilities (Docket No. E-2, Sub 316; Docket No. #-7, Sub 231; Docket No. E-22, Sub 216).

The procedure was developed from a proposal from the Commission Public Staff which would have required utilities to operate all base loaded plants at a predetermined 60 per cent capacity factor to receive full fuel cost adjustment. If a utility fell below the 60 per cent target, its fuel cost recovery formula would be adjusted downward as a penalty unless the firm could present evidence sufficient to convince the Commission to allow full cost recovery.

The Commission adopted a somewhat modified plan. It set a target of 60 per cent capacity factor for base loaded nuclear plants only. Firms' performance is to be reviewed twice yearly. If any plant fails to achieve at least a 60 per cent capacity factor, the Commission would hold hearings to investigate and then:

...upon finding from the evidence that any outage was caused by imprudent management, shall determine to what extent any resultant excess fuel expense shall be disallowed as an adjustment to the fuel costs to be charged in subsequent periods. (Docket No. E-22, Sub 216, p. 9)

Comments

The plan has not been in use long enough to measure its effects on power plant availability. It is designed to focus utilities' attention on one measure of productivity, the capacity factor. The Commission felt that normal payment lags gave utilities an incentive to minimize cost with respect to fuel expenditures but believed that incentives to achieve the least cost generation mix were

lacking (North Carolina has a mix of coal, oil and nuclear plants with minimal hydro generation). The Commission's decision to direct attention to the capacity factor of only nuclear plants reflects the fact that the variable cost of nuclear generation is the lowest of all generation modes available in North Carolina. Therefore these plants should be utilized whenever possible.

The plan relies on disincentives for inferior performance rather than incentives for achieving the stated goal:

Upon finding imprudent management to be the cause of an outage(s), the performance or disallowance of any resultant excess costs shall be determined after considering the length of the outage, the cost of fossil, hydro, or purchased power replacing the down unit, the lowest capacity level at which nuclear generation "breaks even" economically with efficient coal-fired generation, the prior performance of the units involved, the newness of the units, and the level of responsibility exercised by the utility, as well as other relevant factors suggested by the parties. (Docket No. E-22, Sub 216, p. 6).

Florida, Kentucky, Pennsylvania, Virginia

Several other state utility commissions are now more actively trying to promote productivity but on a case by case basis rather than by adopting a formula mechanism. The Florida Public Service Commission makes a case by case review of all outages. If it is determined that the length of the outage was due to poor management, the Commission sets rates after inputting a capacity factor which would have obtained if the unit had not gone down. This results in rates less than that required to recover all purchased power costs during the outage. The Florida Commission has devoted most of its attention to improving the productivity of nuclear plants (it currently has four such plants with the fifth to come on line within five years) because the variable cost of nuclear units is lower than that of fossil fuel generators.

The Kentucky Public Service Commission has discussed tying the fuel adjustment clause to some measure of productivity. Thus far, these discussions have

not gone beyond the staff level, however. The potential difficulties of undesired side effects which result from use of a single productivity performance measure have been an obstacle to the adoption of any official action.

Similarly, the staff of the Pennsylvania Public Utilities Commission tried to develop a method of tying the fuel adjustment mechanism to capacity factor, heat rate, or some other measure of productivity but eventually discarded the idea as being unworkable.

The Virginia State Corporation Commission considers a five year history of outages, capacity factor, and availability in reviewing rate increase requests but any incentive to improve productivity currently occurs on an ad hoc basis. The dominant view at the Commission appears to be that the data which would be necessary to make an incentive formula operational do not currently exist.

New York

The New York Department of Public Service currently deals with questions of utility productivity on an ad hoc basis as part of normal rate hearings but has established a Task Force on Powerplant Productivity to formulate new policy. Part of the impetus for new policy is the experience with scheduled shut downs of nuclear generating units. In the summer of 1976, the Consolidated Edison Indian Point II reactor was shut down for a scheduled refueling. This planned outage was supposed to last 3 months but actually took 6 months. The Department estimated that the extra fuel costs resulted in ratepayers paying approximately \$20 million more than they would have if the outage had lasted only 3 months. The Department is currently seeking a \$20 million rebate from the company arguing that the outage came about because of poor management resulting in part from the disincentive effects of the fuel adjustment clause.

The Department feels that making productivity an issue in specific cases will focus attention of other utilities on the issue and will eventually improve their performance. The goals of the Task Force on Powerplant Productivity are to improve information flows among utilities involving productivity improvements and to establish and monitor "efficient" plant maintenance schedules.

Summary and Evaluation of Incentive Procedures in States Other Than Illinois

The actions taken by various state public utility commissions to improve productivity of utilities can be categorized into two basic groups: formula mechanisms for improving productivity and ad hoc approaches to productivity improvement.

The formula mechanisms include those in Connecticut and North Carolina which tie fuel cost recovery to capacity factor and the Michigan system which provides a bonus or penalty on the rate of return depending on system availability. In addition to specific comments given above on each of the plans, they share one important weakness: each of them is based on a partial measure of productivity and as a result may introduce unplanned distortions into the firms' operating or investment decisions. The optimal level of availability, capacity factor, or outage rate is that such that the marginal social cost of such improvement. But there is no assurance that the optimal level will be achieved with the incentive mechanisms which have been reviewed. Suppose the state commission focuses the utilities' attention on availability by providing a bonus for improvement. The firm may be motivated to "buy" more availability than is socially optimal. One way of improving availability would be to increase short run operation and maintenance expenditures. Since these costs are

generally allowable expenses which compose part of the firms' revenue requirements, the customer pays higher rates to cover both increased O&M costs and the higher allowed rate of return due to the availability improvement.

It could be argued, of course, that increases in short run O&M costs will be cost effective in the long run if availability can be permanently improved. But if this is true, then the firm has an existing incentive to undertake such improvements so long as the actual rate of return is below that which is authorized. It loses this incentive only when the authorized rate is a binding constraint. In this case, the availability incentive scheme could be a cost effective mechanism but as it is currently in use in Michigan there is no provision for distinguishing between the case in which the firm has an existing incentive to cut costs because its actual rate is less than that allowed and the case in which the firm is earning the allowed rate. In the latter case, the only existing incentive to cut cost would appear to be regulatory lag.

The possibility of adverse side effects from a formula incentive mechanism appears to be a main reason why the utility commission in Kentucky and Pennsylvania rejected the notion after staff consideration. Productivity considerations are now more actively pursued by the Commissions in such states as New York, California, Florida, and Virginia but the approach in each has been on a case by case basis. The commissions attempt to stimulate interest of utilities in improving productivity by raising productivity related issues in specific cases.

The Illinois Bell Cost and Efficiency Adjustment Clause

In March 1974 Illinois Bell Telephone Company proposed to the Illinois Commerce Commission a revenue adjustment clause which would explicitly account for

productivity changes. It is an automatic revenue adjustment mechanism which would allow the firm to recover increases in unit cost provided its total factor productivity increases at the historic rate for the firm. The cost and efficiency adjustment (CEA) is defined as $CEA = (aX + bY)$, or Z , whichever is less:

where

- X = Aggregate dollar value of the percentage change in unit costs (plus or minus) exclusive of net income (return to equity) before income taxes
- Y = aggregate dollar cost savings (plus or minus) associated with changes in efficiency
- Z = change in aggregate revenue (plus or minus) required to meet the allowed ceiling rate of return
- a, b = coefficients as specified in the tariff to permit full recovery of unit cost changes if the change in total productivity equals or exceeds the recent trend rate for the company. (Kendrick [1975], p. 306).

Illinois Bell proposed that $a = .5$ and $b = 1.5$. This would mean the firm would receive only one half of cost increases via automatic revenue adjustment. To receive full recovery of costs the firm would have to experience a productivity increase equal to that of past periods for the firm.

The measure of productivity proposed was the total factor productivity developed by Kendrick (1961, 1973). Three categories of inputs were included:

1. Real labor cost, broken down by occupational groups;
2. Cost of intermediate products such as purchased materials and outside services deflated by the Wholesale Price Index; and
3. Real capital changes.

Comments

Although the Illinois Commerce Commission did not approve the CEA scheme, it is one of the most sophisticated revenue adjustment mechanisms which has been proposed to date. It attempts to account for productivity change with respect to all factors of production and relies on data which are readily available. A major disadvantage is that the firm has an incentive to improve its productivity over historic rates only at relatively high rates of general price inflation. At inflation rates below 8 per cent, the firm can recover all its costs while having lower productivity than in previous years (see Kendrick [1975], Table 3, p. 307).

A further weakness of the proposal is that it ignores substitution among factors of production due to changes in relative prices. This objection can be overcome by explicitly incorporating an estimate of the firm's production into the formula (Ram-Mohan et al [1977]) but the data requirements for the successful operation of such an arrangement may be too stringent to be practical.

IV. Discussion of Incentives for Illinois

An extensive review of the regulatory economics literature is discussed in Appendix A. One of the main conclusions is that although there are substantial theoretical and empirical justifications for the Averch-Johnson capital-intensive bias for regulated utilities, the exact effects depend upon the dynamics of regulatory lag and, within limits, the longer the lag the less the impact of the Averch-Johnson effect. However, the Averch-Johnson literature deals exclusively with long run biases that result from distortions in relative factor prices and therefore it is not directly relevant to the issue of improvements in productivity of existing capital. There is a much smaller body of research on productivity improvement and insights from this literature are incorporated into the candidate incentives discussed below.

The literature survey and study of the existing regulatory environment in Illinois as well as in other selected states has yielded the following general conclusions. If socially cost effective productivity improvement projects are not being undertaken by utilities, there are three alternative reasons:

first, utilities are not aware of the technology which would allow cost effective improvements to be made; second, there is no economic incentive for the projects to be undertaken; third, incentives exist but the projects are not undertaken because of managerial ineptness.

The regulatory agency can effectively deal with the first two but it is greatly limited in its power to affect the third. Because the candidate incentives which follow have been developed with these factors in mind, it is important to discuss the latter point in more detail.

The raison d'être of utility regulation has always been to prevent the allocational and distributional consequences of unconstrained monopoly power. The most obvious constraint imposed by regulation is control over the price which

the monopolist can charge. Because the firm no longer can charge the price it wishes, its incentives are altered in a variety of ways which range from the disincentive for efficiency in the simple cost-plus pricing case to the more complex--but equally costly--factor price distortions which have been described in the Averch-Johnson literature.

Regulation is a second best approach resulting from market failure and, as such, it can never achieve the first best results of a purely competitive market. Evaluating alternative regulatory policies is therefore a matter of choosing the least imperfect policy option.

Regulation can do a great deal toward improving information flows and in affecting economic incentives of the regulated firms. But unless regulators are willing to supplant the function of management, regulation will not be effective in the long run at correcting deficiencies resulting from managerial mistakes. In unregulated industries, forces operate against managerial ineffectiveness both from within the firm and from the market. Management which consistently makes wrong decisions or ignores profitable alternatives will have difficulty maintaining itself in control as the value of owners' equity is eroded by the entry of well managed firms into the market. If the owners do not remove the incompetent managers then they will be removed eventually by the firm's decline and bankruptcy.

Neither of these controls on managerial competence will work effectively under regulation. The threat of potential entry is thwarted by the technology of production and the legal barrier of regulation. Stockholder revolt is also likely to be an ineffective control on management performance unless the managers of the firm are blatantly incompetent. Only a modicum of alertness on the part of management is required to recognize that a worsening in owners' wealth positions can as easily be attributed to hidebound or vindictive regulation as

to management mistakes. Nor is threatening a firm with bankruptcy a realistic option for most regulators. Not only are there legal constraints on a public utility commission's ability to "destroy" a firm, no matter how poorly managed, there would also be widespread political opposition to such a regulatory strategy.

Unless regulators are able and willing to second guess each management decision there is no way of insuring that socially optimal decisions will always be made. The most that regulation can do is to configure the incentive structure within which the firm operates so as to increase the probability that socially optimal decisions will be made.

Attempts by the regulator to improve utility efficiency by exhorting or threatening the utility will be less effective absent a specific economic incentive. If an economic incentive is present, then exhortation or threats are unnecessary if management is competent to evaluate and respond rationally to those incentives. If management is incompetent, then no amount of "jawboning" may be effective in improving the overall performance of the firm even in the presence of incentives.

The case of New York State provides an interesting example. The New York Public Service Commission is widely regarded as an example of a highly professional and activist regulatory agency. It has been in the forefront in directing attention to issues of utility productivity. For example, the single most useful source on the definition and measurement of utility efficiency (Balk and Shafnitz [1975]) was done under its aegis. It has adopted the role of advocate and monitor of utility efficiency with exuberance. Consolidated Edison has frequently been the subject of its attention and a Commission-sponsored management study of the firm by Arthur D. Little, Inc. in 1976 concluded that more efficient operation would net the firm more than \$27 million annually. The Com-

mission has not been reluctant to "punish" the firm for specific cases of apparent mismanagement. Indeed, it seems the Commission continually hits the firm with successively larger sticks--witness its current attempt to disallow \$20 million in outage costs. However, it is still not clear how cost effective this approach has been.

Candidate Incentives

A. Improve Information Flows Regarding Potential Productivity Improvements

The Commission could focus utility attention on productivity issues not only by publicly proclaiming their importance but also by facilitating the dispersal of information to utilities regarding possible productivity improvements such as the technical research conducted by DOE or trade associations.

Advantages. This could be the least costly procedure to the extent that it involves dispersing information which already exists. There appears to be little chance of causing any allocative distortions.

Disadvantages. Procedure will be effective only to the extent that utilities do not currently have access to full information regarding productivity improvements--which seems doubtful--and to the extent that there exist economic incentives to put the productivity improvements into effect.

B. Institution of Efficiency Incentives Tied to Rate of Return

Normal regulatory lag provides some incentive for efficiency to the extent that the actual rate of return is on average less than that authorized. Regulatory lag alone, however, would not likely provide the socially optimal amount of productivity improvement once the actual rate of return approaches that allowed because the firm's choices of improvement projects would be biased toward those with the shortest payback period. Two incentives are suggested to deal with this problem:

- a. Construction work in progress should be allowed if the firm can demonstrate that the expenditure is directed toward expected improvements in powerplant productivity.

- b. The utility should be allowed to earn above the authorized rate of return providing it demonstrate an improvement in overall productivity compared to its own historical trend or compared to the industry average (this may require modification of the Public Utilities Act). That is, if the firm earns above its allowed rate because of efficiencies, its rates should not be reduced the full amount necessary to return its rate of return to the previously allowed level. Otherwise, the only incentive to undertake productivity improvements when earning near the allowed rate of return is the normal regulatory lag.

Advantages. This is probably the simplest formula incentive-scheme which could be effective. It provides no additional incentive so long as the actual rate of return is less than that allowed (this is a significance difference with the Michigan availability incentive plan).

Disadvantages. The Commission would have to individually evaluate each proposed improvement project before granting it status as an allowable cost. Firms' reporting requirements would be increased to some extent as required to monitor their overall productivity.

C. Modification of the Fuel Adjustment Clause

A simple fuel adjustment formula removes incentives for cost minimization in the short run, distorts optimal factor choices in the long run, and removes the beneficial incentive effects of regulatory lag since decreases as well as increases in costs are passed through to the consumer.

The Illinois Fuel Adjustment Clause incorporates two features which may tend to offset the adverse incentive effects of a simple (i.e., fully automatic and instantaneous) adjustment clause. A lag of one to four months is required and an inventory averaging mechanism is used to partially dilute the effects of an increase in fuel prices. The actual extent to which these features remove disincentives is not known and would require a considerable level of effort to estimate. It may be noted, however, that the short run disincentive effects of

the clause are probably negligible since economic loading of units is based largely on incremental generation costs. This procedure ensures the lowest short run variable cost regardless of whether a Fuel Adjustment Clause is operative. On the other hand, the long run disincentive effects of the Illinois FAC on new unit decisions may well be subtle.

Elimination of the current FAC would clearly remove any disincentives it might produce. However, this action could likely serve to increase the frequency of rate cases and aggravate problems of utility working capital requirements. Alternatively the disincentives could be countered through a cost and efficiency adjustment (CEA) clause similar to that proposed to the Illinois Commerce Commission by Illinois Bell Telephone in 1974. The CEA would guarantee recovery of only a portion of increased costs; the balance of increased costs would have to be recovered through productivity improvements. In the original proposal, the clause was defined as follows (for a more extensive discussion see Kendrick [1977] and *supra*, p.).

CEA = $(aX + bY)$, or Z whichever is less
where
X = aggregate percentage dollar change in unit costs
Y = aggregate dollar value of changes in total factor productivity
Z = allowed rate of return

The values a and b are weights attached to the two components of the formula and they determine the strength of the efficiency incentive. Illinois Bell advocated setting $a = .5$ and $b = 1.5$. With normal trend growth in Illinois Bell's total factor productivity these weights would have allowed it to recover all costs so long as inflation was less than 8% annually.

This scheme should be adequate to offset the disincentive effects of guaranteed recovery of costs but, as proposed by Illinois Bell, it would provide no incentive for productivity improvements when the rate of return constraint is

binding. A modification of the above formula is called for. The firm should be allowed to earn increments above the allowed rate of return due to improvements in efficiency. The Z in the above formula would no longer be fixed but would be dependent upon increases in total factor productivity. Such an adjustment mechanism could be defined in the following manner.

Total factor productivity (TFP) would be measured as Kwh per dollar cost and could be expressed as an index relative to some base year. In Ontario Hydro's internal management study of total factor productivity (July 1976, p. 45), for example, 1961 is used as base year so that the index for any given year i is:

$$TFP = \frac{TFP_i}{TFP_{1961}}$$

Representative TFP indices are given in Table 1 for a single firm and for the entire U.S. utility industry.

The rate of return increment above that authorized could be computed in the following way. If the firm exceeds its allowed rate of return, it gets to keep "excess" profit in direct proportion to the difference between its percentage increase in TFP for the year and the long run average percentage increase in TFP. For example, suppose the long run (5 year or 10 year, say) average increase is 2.5% and the firm's TFP increase last year was 100% better, or 5%. In this case it would be allowed to keep all of the excess above its allowed rate of return. That is, its revenue requirements would not be decreased during the current year. If its TFP had increased 3% so that it did only 20% better than the moving average, then its prices would be revised downward so that it is allowed to keep only 20% of the excess rate of return. Notice that with this scheme, the consumer is never worse off in the short run because rates are not increased due to superior performance as is true under the Michigan availability

Table 1

Ontario Hydro's and U.S. Utilities
Percentage Change in Productivity, 1961-1973

<u>Year</u>	<u>Productivity of Ontario Hydro</u>		<u>Productivity of U.S. Utilities</u>	
	<u>Index (1961=100)</u>	<u>% Change</u>	<u>Index (1961=100)</u>	<u>% Change</u>
1961	100.00		100.00	
1962	100.79	0.79	104.33	4.33
1963	98.29	-2.49	107.49	3.03
1964	102.12	3.90	111.27	3.52
1965	108.96	6.70	114.89	3.25
1966	118.01	8.30	120.17	4.60
1967	120.01	1.70	121.83	1.38
1968	126.12	5.08	126.64	3.95
1969	128.10	1.57	130.34	2.92
1970	128.56	0.36	130.18	-0.12
1971	126.25	-1.80	130.42	0.18
1972	134.08	6.20	132.47	1.57
1973	144.81	8.01	134.44	1.49
		Average = 3.19%	Average = 2.51%	

$$\text{Percentage Change in Productivity} = \frac{P_t - P_{(t-1)}}{P_{(t-1)}} \times 100$$

where, P_t = Productivity Index of year (t)

$P_{(t-1)}$ = Productivity Index of year (t-1)

Source: Ontario Hydro (July 1976), Table 4, p. 45.

incentive (a rate of improvement in TFP in excess of 100% would be treated as 100%). The consumer will eventually be better off because an exceptional TFP in a given year raises the moving average against which the firm will be measured in the future.

Advantages. Coupling the cost and efficiency adjustment with the possibility of earning "excess" rates of return due to productivity improvement should offset the adverse incentive effects of the fuel adjustment clause while providing new incentives for productivity improvements. Data requirements for administering the plan are essentially the same as for the procedures discussed in 4.12a and 4.12b.

Disadvantages. This procedure would add complexity to an already complicated regulatory procedure. Indeed, it is probably the most complex of the various incentive mechanisms considered. The proper weights a and b in the CEA clauses would have to be determined carefully to account for the firm's historical productivity trends and the expected rate of inflation. If a and b are not optimized there is some potential for adverse incentives.

It may be noted that in nominal terms, total factor productivity for the electric utility industry has been declining over the past several years. This is primarily due to increased fuel prices as well as increased capital and labor costs, but other factors are also involved. The output of an electric utility is not simply kilowatt hours, a homogeneous commodity. Output supplied during peak periods is more costly than output supplied during offpeak periods, and the mix of the two is subject to change over time. Simply averaging peak and offpeak production together tends to distort the usefulness of the term output. Also, environmental constraints such as scrubbers would cause total factor productivity to decline if output is measured simply as kilowatt hours. The value of cleaner air which results from environmental regulations would also have to be

included in output to account for these changes. If it is assumed that all utilities nationally are affected similarly, then national trends could be used but opportunities for exceptions are abundant.

Conceptually, however, the fact that total factor productivity has been declining is not a serious problem since a utility's performance would be compared to some trend. It is no more difficult to determine whether a utility is doing better than trend when trend is declining than when it is increasing.

D. Concluding Observations

In addition to describing the above candidates for consideration, it is equally important to consider incentive programs which are potentially counter productive. These include any procedure in which the rate of return or cost recovery is tied to a single dimension of performance such as system availability, capacity factor, outage rate, etc. There is a real potential for such schemes to induce long run distortions and eventually increase costs. Any incentive scheme must be tied to a measure of total factor productivity (i.e., overall productivity) to be cost effective in the long run.

A second observation has to do with the delimitation of this study to powerplant productivity. While most potential improvements in productivity probably are to be found at the generation stage, it must be recognized that an ideal productivity measure would account for generation, transmission, and distribution. By focussing incentives only at one stage there is a danger of worsening overall productivity of the firm in the long run.

Finally, the ideal regulatory policy should embody simplicity and consistency. Simplicity minimizes the changes of any unforeseen effects developing and lowers the cost of administration both for the Commission and for the firm.

Consistency minimizes the uncertainty of the firm to the extent that a clearly defined and consistently enforced regulatory policy simplifies the firm's strategy for dealing with the regulator.

V. NEAR-TERM STRATEGIES TO IMPROVE POWER PLANT PRODUCTIVITY IN ILLINOIS

The productivity (equivalent availability) of electrical generating plants in Illinois varies widely from unit to unit and utility to utility. For some units in Illinois the operating availability is well above the national average for comparable units, whereas other units in Illinois have performed significantly below the national averages. Low operating availability of power plants translates into higher operating costs which are passed on to the utilities' rate payers. Because some utilities have been more successful in operating comparable power plants than others it was concluded that there are opportunities for improved power plant productivity.

It is important to note that the objective is to optimize the generation costs per unit rather than simply increase the availability. A utility can increase the productivity to a point where the unit becomes "gold plated". Therefore, all potential increases in power plant productivity must be evaluated with a cost-effectiveness criteria.

Incentives for power plant productivity of regulated public utilities must be examined in the context of the existing regulatory climate. Natural monopolies or public utilities do not have the same incentive mechanism to optimize productivity as unregulated industries which are subjected to competitive market forces. For an industry subject to competitive market forces, the firm which continues to make non-optimal productivity decisions will ultimately be forced out of business by its more efficient competitor. In contrast, for natural monopolies, the state public utility commission is responsible for assuring the public that the firm has optimized operating decisions. The public utility commission must obtain these assurances from the utility while at the same time not

being involved in the day-to-day management of the firm. The incentive for cost minimization in the cost-plus environment of public utility regulation is primarily regulatory lag.

A public utility commission cannot evaluate each business decision of a utility rather it must establish incentives which promote the optimum allocation of resources. Given the narrow range of options available to a public utility commission, there are three alternatives available to promote optimum power plant productivity for utilities under the Commission's jurisdiction:

1. Require information from the utility regarding the rationale for various power plant productivity decisions;
2. Remove regulatory induced disincentives and optimal productivity decisions.
3. Establish explicit rewards and/or penalties.

Improving The Information Flow

From time to time the Illinois Commerce Commission has in rate case decisions requested electric utilities to provide additional information regarding matters of regulatory significance. Examples of such requests include cost-of-service studies, load management studies, time of day rate experiments and management efficiency studies. By ordering a utility to perform a study or to provide information, the Commission mandates the utility to assign a high priority to the topic and in general this ultimately strengthens the utility's expertise in the area. Requesting a utility to conduct a management efficiency audit, for example, forces utility executives to evaluate their management effectiveness and at the same time provides a signal to other utilities to examine their management procedures. Another example of the positive effect of commission required studies is the current generic hearings on load forecasting and its im-

fact on improving the ability of utilities to understand more fully various load forecasting techniques.

To improve the power plant productivity of units performing far below national averages for comparable units, it is recommended that the Illinois Commerce Commission increase the information flow from utilities to the Commission for these specific units only. That is, the Commission can request from the utility information regarding the alternatives available to the utility which would improve the productivity of certain low performance units. The Commission would set a particular level of performance which would trigger a response. The response could very well demonstrate that the utility has done everything feasible to improve the productivity of low performance units.

One advantage of the approach is that the utility would provide to the Commission information which may be available in-house. Presently all utilities have a staff group which examines the productivity of power plants. However, the priority assigned to power plant productivity may vary depending on other activities within the company. In addition, it is natural for key engineers and planners to seek association with construction projects which are in the forefront of utility priorities rather than trying to make existing power plants operate more reliably. By the Commission showing an interest in the power plant productivity, the utility will assign an even higher priority to power plant productivity enhancement activities.

The strategy for improving information flow is an attractive alternative because it focuses only on utilities and units which continually have below par performance. Such a selective use of information requirements rewards utilities with good performance. When the utility presents information to a public agency, the utility must necessarily be able to formally defend the decision. This fact promotes a thorough review of the decision at many levels of management.

The only apparent drawback to this plan is that it could be seized upon too heavily by the affected utilities. As stated earlier, an increase in productivity regardless of cost is not the desired result. Care would have to be exercised by the Commission to ensure that the plan not be viewed as a guideline without flexibility. Thus a utility is not automatically penalized if a unit shows low productivity. Since there is no direct financial incentive involved and since work required of the utility is minimal, it seems that "gold plating" or similar distortions would be avoided.

As a specific example, the Illinois Commerce Commission could ask utilities to provide an analysis, including the costs and benefits, of possible productivity enhancement options for all power plants which have had productivity far below the ten year average for comparable units published by the Edison Electric Institute. The threshold could be ten percentage points below the national equivalent availability for comparable units published by Edison Electric Institute. Threshold value of ten percentage points is offered merely as a triggering level and does not necessarily indicate that ten percentage points below the national average is sub-optimal.

As has occurred, a unit may be operating at relatively high equivalent availability for many years, and then in one year the performance may be very low due to an equipment problem such as the inability of the utility to acquire a replacement turbine blade for eight months. It is conceivable that a utility would respond to a data request for this unit by simply saying that the requisite turbine blade was not available for eight months. Such a simple response would be sufficient in the above mentioned case.

Removing Disincentives

As stated in the previous section of this project, the fuel adjustment clause removes incentives for cost minimization in the short run, distorts optimum factor choices in the long-run and removes the beneficial incentive effects of regulatory lag. Under certain circumstances, the inclusion of oil and gas in the fuel adjustment clause can serve as a disincentive to increasing the productivity from base load coal or nuclear units. In Illinois, the fuel adjustment clause (FAC) for electric utilities was enacted in the late 1950's when utilities were experiencing economies of scale and rate requests were years apart. In one instance, a utility did not apply for a rate increase for 25 years. The FAC provided an automatic mechanism to adjust utilities revenues for charges in the most volatile cost component, fuel.

It must be remembered that the FAC reflects the incremental change in fuel costs between rate cases. The base for fuel costs is fixed during each rate case. Thus, if the cost of coal increases for \$20 to \$21 per ton since the previous rate case, only \$1 is reflected in the FAC and the \$20 per ton is rolled into the base rates during the previous rate proceeding.

A decade ago the FAC deterred formal rate increase filings because fuel was the most variable cost component. However, presently the cost structure programs of electric utilities have become the most variable cost component, and utilities are filing for rate increases almost yearly. The original rationale for the FAC was to deter rate cases and level profits of utilities between rate cases. But now with yearly rate filings of electric utilities with the attendant adjustments to the fuel cost base, the original benefits have been diminished.

In Illinois, the FAC clause includes the costs of coal, oil and gas plus fuel transportations and other costs. In addition, it has been proposed that nuclear fuel and purchased power be included in the FAC. Because in Illinois base load generating units are exclusively coal and nuclear fueled, the inclusion of oil, gas and purchased power serves as a disincentive to optimum productivity from base load units. This occurs because the costs of extraordinary maintenance expenditures are recoverable at the end of the next rate proceeding providing the expenses occurred during the test year accepted for that proceeding. In contrast, the cost of substitute fuel or power is recoverable almost immediately through the FAC.

In Illinois, oil and gas are used for peaker units which are relatively low in fixed costs and high in fuel costs. If, for example, a utility identifies a \$3 million two month program to increase productivity unit to a base load unit, the utility has two options. One alternative is to undertake the \$3 million productivity improvement as quickly as possible recognizing that their near-term non-recoverable expenses will increase by \$3 million. The other alternative is to defer the maintenance unit at a more favorable time and substitute higher marginal cost generation such as oil and gas or purchased power. The latter option could yield higher short-term profits to the company since the cost of substitute oil, gas or power can be recovered almost immediately through the fuel adjustment clause. Under certain circumstances especially in times where additional cash flow is needed, the utility could opt for the latter alternative. Deferred maintenance by railroads to allow for funds for other activities is a classic example of the latter option.

Public utility commissions must establish a system of incentives to enhance power plant productivity rather than be involved in the day-to-day decision-making process of the utility. Therefore, it is recommended that the Commission

should consider deleting oil, gas and purchased power from the fuel adjustment clause as a method to remove disincentives to power plant productivity. Of course, the cost of oil and gas generation will be recovered during the normal rate case cycle, and the oil and gas used for normal peaking operations will be a constant cost year after year. Removing oil and gas from the fuel adjustment clause will provide a greater incentive to power plant productivity and at the same time promote our national energy objective of reducing dependence on imported oil.

Rewards and/or Penalties

Public utilities can recognize superior performance of power plants by establishing an explicit reward at rate increase time. Michigan has adopted such a procedure, whereby utilities which achieve an overall availability of powerplants in excess of 80% are rewarded by an increase in return on equity by 0.5%. While the concept is sound, using the availability factor as the criteria may promote sub-optimal maintenance expenditures. As an alternate, the public utility commission could examine both the productivity and the operating expenses of a plant to determine superior performance and then reward or penalize the utility appropriately.

APPENDIX A

THEORIES OF FIRM BEHAVIOR UNDER REGULATION

Theoretical developments in the regulatory economics literature can be classified into three very broad and, to some extent, overlapping groups the general theory of regulation, cost plus theories, and investment theories. The general theory attempts to provide an explanation for the emergency of regulation. Regulation is viewed either as a mechanism for protecting the public against the adverse effects of monopoly (Bonbright [1961]); or as a method for the industry itself to protect its own economic interests [Posner 1974]; Stigler [1971]).

The cost plus theories are based on the assumption that increases in cost will simply result in increases in rates because of the regulators' inability to determine when costs are inappropriate (Knight [1930]; Baumol [1967]; Posner [1969]). Because the firm can pass costs to the user through complaint regulation, it loses the incentive to minimize costs. In its simplest form this argument obviously ignores the demand constraints on the firm and also the fact that regulatory proceedings can be costly from the firm's standpoint.

Regulatory Bias

Perhaps the most extensive and rigorous group of theories deal with the investment decisions of the firm under regulation. Following the work of Averch and Johnson, these theories consider the allocative and cost impacts of rate of return regulation via distortions in the firm's valuation of relative factor prices.

Most regulation can be viewed as placing an upper limit on the return to capital. There are two justifications for treating regulation as a constraint on the rate of return to capital. First, allowed profit must be defined in terms of some measureable base. Second, figuring profit as a return to capital is consistent with the fundamental economic notion that viability of the firm requires that it be able to compensate its owners with a "normal" return, consistent with risk, which will allow it to continue to attract capital.

Because the constraint applies asymmetrically to the firm's inputs, its internal relative factor prices are changed so that the firm adopts factor ratios which are not optimal given the true relative prices of inputs. For example, if the allowed rate of return is 12%, but the firm's cost of capital is 10%, then in a sense it receives a 2% premium on each unit of capital it acquires. That is, the firm treats capital as if it costs not 12% but $12\% - (12\% - 10\%)$ so that it undervalues capital and adopts an excessively capital intensive technology for any given level of output.³

It should be noted that the theory does not predict "gold plating". e.g., acquisition of completely redundant capital. To show that it would not be in the firm's interest to acquire useless capital, consider its constrained profit function.

(1) $\pi^* = PQ - (wL + sK)$ where π^* is the allowed profit, P is price, Q is quantity, L and w are the quantity of labor and its average wage, respectively, s is the allowed return to capital (assumed greater than the cost of capital), and K is total capital. Rates would be adjusted so that the return to capital would not exceed s . Now suppose that the firm had two types of capital, productive

³The exact distortion from the socially optimal factor ratio is dependent on the firm's demand and cost functions. See Scherer (1970), pp. 530-533.

capital K and redundant capital $\bar{K}$, the latter which is unproductive in a real sense but merely inflates the rate base.

$$(2) \quad \bar{\pi} = PQ - (wL + s(K + \bar{K})).$$

Assume further that productive and unproductive capital can be purchased for the same price. Now if the utility replaces each unit of $\bar{K}$ with a unit of K , its capital productivity would increase allowing it to produce the same level of output using less labor. Since revenue is unchanged and cost has declined (because of less labor being used) the firm now exceeds the constraint because profit has increased. The firm can now increase its use of productive capital until the constraint is satisfied and $\pi^* > \pi$. The firm therefore may "inflate" its rate base but not with useless or unproductive capital. It will not pay the firm to acquire useless capital, because for the same price it can acquire productive capital. "Gold plating" of the capital stock would be rational only in the bazaar case in which the marginal product of capital is negative. See Bailey (1969) and Zajac (1972).

Although the firm does not acquire useless capital it will still adopt a technology which is excessively capital intensive from society's standpoint. Consider first the investment decisions of profit-maximizing monopoly firm which is not constrained by regulation. Its profit function is (3) $\pi = PQ - (wL + iK)$ which differs from (1) only in that the unit cost of capital is now i , its true user cost. Output Q is given by a production function, $Q = Q(L, K)$ and the price is given by the inverse demand function $P = P(Q)$. Profit depends on L and K so that the profit function can be written as $\pi = \pi(L, K)$ and can be visualized as a surface in 3-space with the base of the plane formed by the L and K axes and the third dimension measuring profit (Figure 3). The firm will choose that combination of labor and capital which yields the greatest possible profit

π max, given by the point of the K-L plane which lies directly under the summit of the profit hill.

Now consider an identical firm subject to rate of return regulation. The regulatory constraint can be viewed as an inclined plane defining the maximum allowed profit which is hinged on the L axis. The angle which it forms with the K axis is the allowed rate, s , in equation (1). The firm is restricted to capital labor pairs the profit of which lies on or below the plane. Profit maximization will compel the firm to choose input combination π max.

The allocational consequences of the regulation-induced changes in input choices is more easily described by collapsing Figure 3 into two dimensions. In Figure 4 the constraint curve is the projection of the intersection of the constraint plane and the profit hill in Figure 3. The firm must operate at some point on or outside the curve; points inside represent greater than the allowed rate of return. The locus of efficient points of operation is the curve labelled E. E must pass through π max and pass to the left of π max (for a simple proof of the latter, see Zajac (1970), pp. 119-120). The function labelled Q is an isoquant passing through π max. It represents the different possible combinations of L and K which could be used to produce a constant level of output Q. Note that the maximum constrained profit, π max, lies on the extreme right of the constraint curve. This is an excessively capital intensive combination of inputs because the same output could be produced more efficiently at P. Regulation therefore induces the firm to adopt a nonoptimal expansion path by overcapitalizing with the result that the firm will not achieve least cost production at any given level of output.

Although the model is explicit in its predictions, it omits several crucial variables which may also affect the firm's investment decisions. First, industry representatives have complained that the Averch-Johnson model does not ac-

CONSTRAINT CURVE and OPTIMAL EXPANSION PATH

Fig. 4

count for the factor of uncertainty in the regulatory process and ignores the impact of taxation on investment (Corey [1971]). There is also some empirical evidence to support the argument that the rate of return allowed by the regulatory commission is significantly affected by the size and reasonableness of the firm's requested rate, the extent to which the company documents its cost of capital, the presence of intervenors, and the commission's subjective assessment of the firm's relative efficiency (Jaskow [1972]).

Second, the model implicitly treats capital as being composed of homogeneous and divisible units. But in reality utilities acquire capital in large lumps. If the Averch-Johnson bias impacts on the decision to acquire new capital it likely does so at the margin on the planning level. That is, if the firm is considering several alternative investments, it may be biased toward the more capital-intensive projects even if they are not the most cost effective from society's standpoint. Examples which have been suggested are the acquisition of COMSAT ground relay stations by common carriers, and the Bell System's reluctance to initiate microwave telephone transmission instead of more capital intensive buried cable (see Scherer [1970], pp. 535-36).

Regulatory Lag and the Dynamics of Investment

A major limitation of the Averch-Johnson model is the assumption that the regulatory constraint is always binding, e.g., the regulatory agency reacts instantaneously to changes in demand and cost so that the utility constantly earns the allowed rate of return. However, if there are substantial lags between rate cases, the results of the Averch-Johnson model must be modified. The conclusion that the firm would be led to overcapitalize is based on the assumption that the firm can instantaneously vary its capital stock to constantly achieve that level

which is (privately) optimal and that the regulatory authority is constantly monitoring market changes so as to immediately change rates to maintain a "fair" return on this capital stock.

Suppose, however, that a period of time elapses between rate cases. In the interim, the firm has the incentive to operate as efficiently as possible meaning that overcapitalization would lower actual profit, at least until the next rate hearing. The firm therefore faces a tradeoff illustrated with the constraint curve diagram in Figure 5. Assume the firm is initially operating on the efficient locus at A. By decreasing labor and increasing capital by ΔK_1 , the firm can maintain its output level at Q_a . But because of regulatory lag, its profit will temporarily decrease since its new point of operation at B is off the constraint curve. The firm then files for a rate increase which eventually moves it back to the constraint curve at Point C. Since it still has less than the long run profit maximizing stock of capital (that consistent with $\bar{\pi}$ max in Figure 4), the firm has an incentive to temporarily incur losses again by expanding its capital stock by ΔK_2 with the expectation that increased rates will eventually put it back on the constraint curve. This sort of adjustment would continue until the firm reached point N which represents the greatest attainable level of constrained profit. As the length of the lag between rate increases gets larger, the costs of forgoing profit by being off the constraint curve grow relative to the benefit of the eventual rate increase. With short regulatory lags the Averch-Johnson effect prevails, but as the period between rate cases increases, its importance decreases (Bailey and Coleman [1972]; Davis [1973]).

An extension of this model suggested by Klass (in Klass and Shepherd [1976], pp. 26-27) takes the argument a step further. Suppose that once at π max on the constraint curve, the firm moves toward the efficient locus E along

EFFICIENCY, OVERCAPITALIZATION, and REGULATORY LAG

Fig. 5

isoquant Q_d . It does so by using more nearly optimal combinations of factors so that costs decline and profit rises above the constraint (since any point inside the constraint curve represents a profit rate in excess of that allowed). Eventually, a rate revision will drive it to the constraint curve again at point A, say, so that the cycle begins again. The period of "excess" profit could conceivably finance technological improvements.

...what has saved regulation from being a critical force in the direction of mediocrity and tardy technological progress has been its very "deficiencies" in the form of regulatory lags and in the form of acquiescence by commissions in fairly prolonged periods of theoretically "excessive" earnings on the part of companies whose public reputations and whose comparative rates of charge for service have not made them vulnerable to popular attack. (Bonbright [1961], p. 262).

An additional aspect of regulatory lag deserves attention here also. Completely aside from its effects on the firm's investment decisions, the periodic nature of rate review can have important distributive effects between owners and customers of regulated utilities. Let the regulators' desired rate of return be defined as a price which equals the firm's average total cost (including the "fair" return). Because of lags in the regulatory process, the actual price at any time may be above or below this desired price. In Figure 6, the curve labeled D is the firm's market demand for output. Price P^* is the regulatory "target" price which would allow the firm to cover its cost and receive only the allowed rate of return. Actual price could be either above P^* at P_h or below at P_l . With price above P^* the utility earns a surplus equal to the discounted present value represented by area abfe. With price at P_l it incurs a loss (and consumers gain) an amount equal to the discounted present value represented by area abdc.

Spann (1976) has estimated such a model for the years 1960 and 1973. He assumed an average cost function of the form:

DISTRIBUTIVE EFFECTS of REGULATORY LAG

Fig. 6

$$4) \quad AC(t) = BQe^{(g-x)T}$$

g = rate of inflation,
 x = net rate of productivity in the public utility sector
 Q = quantity of output

Quantity demanded is determined by price, which the regulatory agency has set equal to average cost at the last rate hearing. Economic profit or loss of the firm because of regulatory lag was computed as the present value of differences between average cost and price multiplied by output.

$$5) \quad \pi = \sum \frac{(p(t) - AC(t)) Q(t)}{(1+r)}$$

where r = the rate of discount.

During periods of stable prices and growth in productivity, lag favors the firm but if inflation offsets productivity gains, consumers are in effect being subsidized by utilities by paying rates which do not cover the total cost of production. For the year 1960, a year of moderate inflation, the present value of net income transferred from consumers to utilities as a result of lag was estimated at \$2.18 billion. For 1973, a year of relatively rapid inflation and lower productivity growth, the income transfer was from utilities to consumers and estimated at \$3.8 billion (Spann [1977], p. 832).

Trends in Productivity and Factor Prices

Interest in ways of improving efficiency has increased during the 1970's for a number of reasons. First, most of the potential scale economies of production and distribution appear to have been exploited (seitz [1971]). From the period 1955 to 1970, technological change unrelated to scale also decreased production cost significantly.

...many firms did exploit scale economies between 1955 and 1970. However, for the typical firm, movements along the cost curve resulted in cost declines which were small relative to the downward displacement of the entire curve. (Christensen and Green [1976], p. 674).

However, there is some confounding of scale effects and technical change, since newer vintages of turbine-powered units with larger capacity and higher thermal efficiency also incorporate the results of new technological knowledge. (Cowing [1974], p. 138.)

A second reason for focussing on efficiency improvements has been substantial increases in factor prices for utilities, particularly since 1972. Inflation coupled with regulatory lag has eroded utility earnings and has resulted in frequent rate increase requests. The widespread use of fuel adjustment clauses is largely a response to inflation within a regulated industry. The emphasis which various regulatory agencies are now placing on efficiency improvement may be a result of the fact that frequent rate increases and the automatic cost pass through aspect of most fuel adjustment clauses are politically difficult to defend even if economically justifiable.

Finally, official governmental concern regarding energy in general has stimulated interest in ways of increasing the efficiency of both energy users and producers.

Productivity Definition and Measurement

The term productivity in popular usage has come to mean changes in output per man-hour, usually expressed as an average over all manufacturing industry. Such a measure is not a meaningful index of overall efficiency because it focuses only on the labor input and therefore ignores the possibility of factor substitution. Ideally, a productivity index should be a measure of the conversion of all factor inputs into outputs. One of the most widely used such total

factor productivity measures is that developed by endrick (1961) for the National Bureau of Economic Research. It is an input-output ratio adjusted for intertemporal changes in factor prices. It is defined as:

$$6) \quad TP = \frac{Q_t}{\sum P_j I_{jt}}$$

where

TP = total factor productivity
 Q_t = quantity of output in year t
 P_j = price of input j
 I_{jt} = quantity of input j in year t.

Increases in total factor productivity mean the firm can increase output with a constant expenditure on inputs; or, it can decrease the total cost of a given output level. In an industry in which price is based on input costs, changes in productivity should move inversely with changes in the average selling price of output (see Figure 7).

One disadvantage with this total factor productivity measure is that it measures inputs in dollar terms and may therefore obscure the underlying reasons for changes in measured total factor productivity. It could increase because of a disembodied technological change or because of factor price changes unrelated to technology. It may be important to make such a distinction particularly with regard to input price distortions of the Averch-Johnson type.

Price and Technical Efficiency

It is useful to make the distinction between price effects and real effects more explicitly. In Figure 8, the two inputs K and L are used to produce some level of output, Q. The isoquants Q_a and Q_b represent the same level of output but Q_b is inefficient; it requires more of at least one input to produce A than

PRICE per KWH and TOTAL FACTOR PRODUCTIVITY
for ALL U.S. UTILITIES (1951-72)

SOURCE: Rodney Stevenson, "Productivity in the Private Electric Industry," in Bulk and Shatnitz (1975), p. 32.

does the efficient or frontier isoquant Q_a . To achieve the least cost point of production, a firm will choose a point such that the ratio of factor prices (given by the slope of isocosts AA' and BB') is equal to the ratio of the marginal product of each factor (given by the slope of the isoquant). It follows that a completely efficient firm would operate at point E, the point at which the cost of producing Q is minimized. A firm can fail to achieve least cost because of failure to operate on the efficient isoquant--technical inefficiency; or because of failure to respond to the correct factor price ratio--price inefficiency. A firm operating at point X is price efficient but technically inefficient. A firm operating at point Y, on the other hand, is completely efficient in a technical sense but is price inefficient because it is using a non-optimal combination of factors. It should be reiterated that the latter describes the predictions of the Averch-Johnson model and its many variants. The firm may not be wasteful in a technical sense, and may be perfectly efficient in a price sense from its own perspective. But it fails to achieve least cost from society's standpoint because it responds to a socially inappropriate factor price ratio.

PRICE EFFICIENCY VERSUS TECHNICAL EFFICIENCY

Fig. 8

APPENDIX B

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