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Incentive Regulation of Nuclear Power Plants by State Regulators

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Prepared for
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ABSTRACT

The Nuclear Regulatory Commission (NRC) monitors incentive programs established by state regulators in order to obtain current information and to consider the potential safety effects of the incentive programs as applied to nuclear units. The current report is an update of NUREG/CR-5509, Incentive Regulation of Nuclear Power Plants by State Public Utility Commissions, published in December 1989.

The information in this report was obtained from interviews conducted with each state regulator and each utility with a minimum entitlement of 10%. The agreements, orders, and settlements from which each incentive program was implemented were reviewed as required. The interviews and supporting documentation form the basis for the individual state reports describing the structure and financial impact of each incentive program.

The programs currently in effect represent the adoption of an existing nuclear performance incentive program proposal and one new program. In addition, since 1989 a number of nuclear units have been included in one existing program; while one program was discontinued and another one concluded.

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Incentive programs employed by state regulators may have the potential to influence operational decisions and the financial status of a utility, which in turn may affect the safe operation of a nuclear unit. In an effort to evaluate the potential safety impact of state economic regulation, the NRC periodically reviews incentive programs applicable to commercial nuclear units. This report is an update of NUREG/CR-5509, Incentive Regulation of Nuclear Power Plants by State Public Utility Commissions, published in December 1989. The primary purpose of the current report is to describe how specific nuclear performance incentive programs work and to provide background information for use in evaluating the possible safety implications of the programs.

Generally, an incentive program establishes a performance standard used in utility fuel clause proceedings to determine the recovery of generating costs, including costs resulting from nuclear unit outages. Incentive programs employed by state regulators measure a utility's performance in operating generating units and determine appropriate revenue adjustments based on measured performance. That is, the utility is rewarded or penalized for performance above or below established levels. Frequently, incentive programs function in lieu of routine prudency reviews of utility costs. An incentive program may also be characterized as a mechanism by which the state regulator allocates an appropriate share of the costs associated with nuclear unit outages between the utility and the ratepayers.

Due to the difficultly in distinguishing between incentive programs which specifically address nuclear performance and the various mechanisms state regulators use to adjust utility revenues, this report applies a classification system to differentiate among types of incentive programs. Incentive programs may be classified into one of three broad categories: nuclear performance incentive programs, utility performance standard programs, and utility economic incentive programs. The correlation between revenue adjustments and established levels of performance is a key aspect of the definition of a nuclear performance incentive program. A "nuclear performance incentive program" uses an objective, predetermined formula and uses this measure to determine the magnitude of a financial reward or penalty. "Utility performance standard programs" and "utility economic incentive programs" are general classifications, distinct from nuclear performance standard programs. Each of these two general classes of programs exhibit a wide variety of requirements, but generally they emphasize either performance or economic standards. Frequently, both utility performance standard programs and utility economic incentive programs emulate the established state regulatory practice of subjectively reviewing operating costs in determining recovery of fuel costs.

The investor-owned utilities selected for inclusion in the current report have a minimum entitlement of 10% in an individual nuclear unit. The structure and financial impact of each state incentive program is detailed in individual reports grouped by state regulatory authority. This information was obtained primarily through telephone interviews conducted with state regulators and

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utilities. Incentive programs established by state regulators are currently applicable to 60 nuclear units in 16 states. There are 21 incentive programs applicable to 27 utilities. The total number of incentive programs is composed of 11 nuclear performance incentive programs, 7 utility performance standard programs, and 3 utility economic incentive programs. Nine of the nuclear performance incentive programs apply both rewards and penalties; the remaining two programs use a banked reward mechanism and penalties. Each of the utility performance standard programs apply economic adjustments based on the subjective review of measured performance. Similarly, an adjustment to the rate of return on equity applies to two utility economic incentive programs. The report also includes individual reports on a number of proposed, concluded, or unique incentive programs.

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1.0 INTRODUCTION

1.1 PURPOSE

This report provides information on the methodology and potential financial impacts of incentive programs applicable to commercial nuclear units. The report is an update of NUREG/CR-5509, Incentive Regulation of Nuclear Power Plants by State Public Utility Commissions, published in December 1989. The NRC staff informed the Commission of its effort to track nuclear performance incentive programs in SECY-85-260 (July 26, 1985). The primary purpose of the current report is to describe how specific nuclear performance incentive programs work and to provide background information for use in evaluating the possible safety implications of the programs. In addition, the report distinguishes among various classes of incentive programs and summarizes discontinued programs.

1.2 DESCRIPTION AND CLASSIFICATION OF INCENTIVE PROGRAMS

Incentive programs are used by state regulators to measure a utility's efficiency in operating generating units and to financially reward or penalize the utility for performance above or below established levels. The objectives of an incentive program is to encourage sustained or improved performance and to achieve better economic performance with less regulation. Frequently, an incentive program establishes a standard to be used in fuel clause proceedings to determine the recovery of costs, including costs resulting from nuclear unit outages. The programs are intended to avoid the uncertainty and complexity inherent in case-by-case prudency proceedings. In addition, an incentive program is a mechanism by which the state regulator allocates an appropriate share of the costs associated with nuclear unit outages between utility investors and the ratepayers.

It is frequently difficult to distinguish nuclear performance incentive programs from the various mechanisms state regulators use to adjust utility revenues since they share many of the same features. The revenue adjustments of incentive programs generally take the form of a reward or penalty, usually based on fuel costs. There are revenue adjustment mechanisms associated with fuel cost-recovery procedures where the state regulator subjectively examines performance without the use of specified criteria such as capacity factor or availability. Other revenue adjustment mechanisms establish performance standards characteristic of incentive programs that are employed only to the extent that they are one of many factors considered in fuel cost recovery, and are infrequently associated with a prescribed penalty or reward. Alternatively, a number of state regulators adjust revenues as a function of a utility's management of the generating system's total fuel costs rather than the performance of the units. As a result of the various techniques used by states to adjust utility revenues, it is necessary to develop and apply a classification system for differentiating among types of incentive programs.

Incentive programs may be classified into one of three broad categories: nuclear performance incentive programs, utility performance standard programs, and utility economic incentive programs. A key aspect of the definition of nuclear performance incentive programs is the correlation between revenue adjustments and established levels of performance. A nuclear performance incentive program uses an objective, predetermined formula for determining the size of any financial reward or penalty based on performance. All forms of nuclear performance incentive programs use specific nuclear performance standards. However, incentive programs may apply solely to a utility's nuclear units or may include all system generating assets as well. Nuclear performance incentive programs vary widely in the criteria used to measure performance. The criteria may include heat rate, capacity factor, or availability factor. Programs may be based on only one measure of performance; however, a number of programs employ more than one measure. The revenue adjustments applied also vary from program to program. The majority of programs reward good performance and penalize poor performance. The revenue adjustments can be substantial, potentially involving many millions of dollars. Some programs include a "deadband," a zone of performance in which neither rewards nor penalties accrue. Nuclear performance incentive programs are often quite complex and may exert effects in indirect and complex ways.

Utility performance standard programs and utility economic incentive programs are intended to be general classifications, distinct from nuclear performance standard programs. Each of these two general classes of programs exhibit a wide variety of requirements, but generally either emphasizes performance standards or economic standards; placing these programs in separate classes is intended to capture this distinction. Both utility performance standard programs and utility economic incentive programs emulate the established state regulatory practice of subjectively reviewing operating costs, including those costs associated with a nuclear unit. Utility performance standard programs use performance standards, characteristic of nuclear performance standard programs, as indicators of efficiency. The standards are used by the state regulator in order to determine the prudency or reasonableness of operations. Performance standards in these programs are indirectly and subjectively used to implement economic sanctions upon a utility. Utility economic incentive programs are not directly linked to generating asset performance, but provide for revenue adjustments based on a utility efficiency parameter such as total fuel costs (across all modes of production).

1.3 THE POTENTIAL INFLUENCE OF NUCLEAR PERFORMANCE INCENTIVE PROGRAMS

There is considerable debate within and between the regulated utilities and their trade groups, the state regulators, the National Association of Regulatory Utility Commissioners, and various public interest groups as to the soundness and fairness of incentive programs. It is a difficult task to develop an incentive program for a utility that faithfully models the public interest with respect to a utility's reliability and economy. Questions have been raised about whether an imperfect incentive program enables a utility to unknowingly act against the public interest or adversely affect public health and safety.

Nuclear performance incentive programs have the potential to influence operational decisions, the financial status of a utility, and the safe operation of a nuclear unit. The level of safety performance varies greatly among nuclear units and the important question is whether incentive programs affect unit safety. The utility and state regulatory personnel contacted in the survey usually were knowledgeable about the potential influence of incentive programs applicable to their nuclear units. Utilities, for the most part, have indicated that nuclear performance standards have not had an appreciable impact on the management of nuclear units. However, in many cases, the standards have been in effect for a relatively brief period of time and this time period may not have been long enough to determine the operational impact.

State regulators frequently conduct periodic, routine reviews of utility operating costs, including those associated with nuclear units. State regulators may subject a utility to disallowances on the basis of imprudently incurred fuel costs. The primary disadvantage of routine reviews is the retrospective, subjective examination of performance and utility management. The financial consequences of poor unit performance or reduced system generation are, to a great extent, unknown and therefore difficult to predict. The structured revenue adjustments associated with performance that are used in incentive programs have been cited by both utilities and state regulators as an advantage of incentive programs. Generally, incentive programs function in lieu of routine prudency reviews. Prudent operations on the part of the utility are implicit in criterion level performance. Some incentive programs have replaced the adversarial subjective proceedings with constructive fuel cost-recovery mechanisms. Incentive programs are not necessarily intended to be extremely punitive; programs usually provide for a detailed review of performance in extraordinary circumstances, such as an annual capacity factor of less than 50%. In these circumstances, the application of a specified penalty would also be examined for appropriateness.

It has been suggested that the potential rewards and penalties of incentive programs attributed to nuclear performance are significant when compared to nuclear unit operating budgets and staff salaries. However, the rewards and penalties associated with incentive programs may be small with respect to utility revenues. Nevertheless, the revenue adjustments imposed by the nuclear performance incentive programs clearly result in an impact on ratepayers and utility investors. Disallowance of replacement fuel costs results in savings for the ratepayers and a measurable cost to the utilities. The impact of performance standards on the financial health of utilities, however, has been characterized as small (NUREG-1256, Vol. 1, 1987).

Incentive programs may minimally affect the budgets of utilities as the programs are intended to function as an alternative to routine individual outage reviews and fuel cost disallowances. However, the visibility of the penalties and the resulting decrease in revenues are frequently viewed by the utility as equally undesirable. Ratepayers and utility stockholders may view penalties as an indication of deficient management. The imposition of nuclear performance standards on utilities has, in a number of cases, impacted investments in utilities' generating assets; a number of financial rating agencies have reacted unfavorably to the imposition of incentive programs. Selected utilities have expressed general concern over the reactions of the financial community, pointing out that the major rating agencies have downgraded a few utility securities (Franklin and Hirvo, 1990).

While the NRC has not conducted a detailed safety impact analysis regarding the effects of implemented incentive programs, the influence of such programs on reactor safety is believed to be small. Irrespective of whether a utility is affected by the application of incentive programs, the Atomic Energy Act requires a utility that operates a nuclear unit to comply with NRC regulations and requirements. NRC regulations, together with licensee conditions concerning operations and maintenance, require acceptable safety designs and safe operation of nuclear units. Furthermore, the NRC, through its licensing and inspection activities, verifies that licensees are adhering to safe practices. Nevertheless, economic regulation and, specifically, nuclear performance incentive programs may have the potential to indirectly influence a licensee's approach to reactor safety issues in situations not addressed in license conditions. In fact, performance incentives may have positive or negative influences upon safety.

Selected incentive programs indirectly reward a utility for correcting recurrent or predictable failures, or degradations that could lead to unit outage or derating. Unanticipated shutdowns could challenge safety systems and in extreme cases, trigger accidents. In addition, incentive programs may encourage high morale and a quest for excellence in a utility's operation, which may improve both safety and economic performance. Even though incentive programs may have these effects, utilities have indicated that the operation of nuclear units involves more important factors than potential revenue adjustments tied to an incentive program.

The potential also exists that, in the interest of real or perceived short-term economies, a utility may delay necessary repairs, maintenance, and upgrades or reduce the length of required outages in order to meet an incentive criterion. Such decisions, which do not allow for adequate attention to be devoted to the units, may ultimately compromise the safety of operations. It has been suggested that an incentive program may indirectly foster decisions that would maximize measured performance at the potential expense of plant safety. Yet, such practices would ultimately work against a utility. A unit operating in less than optimal condition may have an increased number of unplanned outages and, thereby, effectively increase penalties. In one example, a nuclear performance incentive program has had a demonstratively positive effect. In this case, management increased the priority of preventative maintenance and safe operations; the results reflected in increased operating budgets. Based on this example, it may be hypothesized that incentive programs can work to create efficiency-based, safe, and well-maintained units with high operating standards.

1.4 THE NUCLEAR REGULATORY COMMISSION AND NUCLEAR PERFORMANCE INCENTIVE PROGRAMS

The NRC staff continues to study, on a generic basis, the possible effects that incentive programs could have on nuclear unit safety. It has been suggested that the structure of incentive programs may affect the balance between practices conducive to safe operations and practices that (in the short run) could increase revenues. The effect of incentive programs on nuclear safety will hinge on utility managements' reaction to the program; that is, how management will address operational plans, operating instructions, and other measures that may evolve in response to the incentive program's provisions.

In 1987, the New York Public Service Commission proposed an incentive program intended to enhance utilities' attention to nuclear safety (NUREG-1256 Vol. 1, 1987; NUREG/CR-5509, 1989). The program was to employ the NRC's Systematic Assessment of Licensee Performance (SALP) ratings and enforcement programs as a basis for financial rewards or penalties. The proposed program was withdrawn. However, the Boston Edison settlement agreement implemented an incentive program for Pilgrim in November 1989 which measures annual performance as a function of capacity factor, a set of five performance indicators, and SALP ratings. Programs that employ SALP ratings have raised a number of NRC concerns.

The prospect of financial rewards or penalties for a utility based on SALP ratings is one of the issues that concerns the NRC, because the focus of the SALP process may shift from the underlying issues to the numerical ratings. The NRC's SALP program was primarily developed to assist the NRC in determining the best allocation of its inspection resources. Based on the NRC's perception of licensee performance, the SALP program identifies nuclear units and program areas that need the most attention. In any particular SALP report, specific areas may be added or deleted based on site-specific considerations. The NRC staff focuses on the issues identified in the SALP report and apparent root causes of problems. The NRC is concerned that the safety of the unit could be adversely affected if the issues identified in SALP reports are obscured because of concerns over the financial consequences incurred as a result of specific SALP ratings.

The NRC is also concerned about the potential effects of SALP-based programs on the NRC's interaction with licensee staff. The NRC's effectiveness in inspecting nuclear units depends, to a significant degree, on having an open relationship with the operating staff and management at the nuclear unit. The operating staff report problems to NRC inspectors that may not otherwise be revealed in the course of the NRC's routine inspection program. The NRC encourages such a relationship and is careful to see that plant staff are not reprimanded for disclosing problems of possible safety-significance. The NRC perceives a program that employs SALP ratings as one that could inhibit the operating staff and management from disclosing safety significant information which is cause for major concern. In addition, the NRC is concerned that an incentive program that uses SALP ratings could impose a large economic penalty on a licensee for minimally satisfactory performance. Such a penalty could reduce resources that might otherwise be available to improve safety performance.

In view of these concerns, the NRC does not support use of SALP ratings or enforcement history to arrive at financial rewards and penalties. Incentive programs that focus on nuclear safety rather than the economic operation of nuclear units have one more drawback - they may interfere with the exclusive Federal regulatory authority under the Atomic Energy Act over safety matters at nuclear units.

The staff responded in SECY-90-046 (February 13, 1990) to the Commission's request for an assessment of the potential financial impacts of incentive programs as well as any health and safety concerns. The SECY-90-046 report identified six state incentive programs that were viewed as programs at risk; that is, programs with the potential to significantly impact the financial status of a utility. Three additional programs were also identified as having specific program aspects of concern to the NRC. An assessment of the potential financial impacts was conducted for these nine programs. The staff concluded that a reduction in the priority of safety at the nuclear units subject to one of the programs would occur gradually in response to financial problems. The NRC staff viewed the NRC's inspection program as a significant tool to aid in detecting degradation in operations before significant safety problems develop.

The report also discussed two options available to the Commission to address concerns regarding incentive programs. The first option included a number of possible courses of action directed at the state PUCs, utilities, and nuclear units. The second option presented to the NRC was the modification of programs controlled by the NRC, such as the SALP program, to eliminate their misuse.

Subsequently, the Commission staff proposed a policy statement regarding incentive programs in SECY-90-288 (August 15, 1990), to set forth the views of the Commission and provide a mechanism to monitor and evaluate the potential safety consequences of incentive programs. A draft policy statement (55 FR 4323) issued in October 1990, addresses the Commission's points of concern. In addition, the draft policy statement requested utilities licensed to operate nuclear units, the state regulators, and the Federal Energy Regulatory Commission to notify the NRC of initiatives to develop incentive programs that will apply to nuclear reactors or to make major modifications to existing programs.

The draft policy statement explicitly cites two features of incentive programs which could adversely affect public health and safety. These features are sharp thresholds across the range of rewards, the deadband, and the range of penalties and performance measurements having short time intervals. The draft policy statement also lists general characteristics of programs that are desirable (or neutral) or undesirable in their potential safety impact:

> A desirable plan provides incentives to make improvements in operation and maintenance that result in long-term improvement in the reliability of the reactor, main generation, and their support systems. An undesirable plan provides incentive to operate a facility with potential safety problems or to start up before fully ready merely to meet an operational goal.

1.5 METHODOLOGY

The utilities selected for inclusion in the current report are investor-owned (publicly owned systems have been excluded). Utilities must have a minimum investment of 10% in an individual nuclear unit to be included in the report.

Information was primarily obtained in telephone interviews conducted with state regulators and utilities. Following each interview, a copy of the applicable 1989 individual incentive program report was sent to each utility and state regulator along with a letter asking for comments and corrections to the report. The agreements, orders, and settlements, which implement each nuclear performance incentive program, were reviewed as required.

Information was collected from the following sources: all utilities reported in NUREG/CR-5509 to be subject to a incentive program; all utilities potentially subject to an existing incentive program; and all state regulatory agencies that have implemented an incentive program. In addition, state regulators were contacted in states where a utility either operated or made a significant investment (greater than 10%) in a nuclear unit and, consequently, was a candidate for incentive program application. If a state regulator indicated in the initial interview that there were no proposed or established programs, further interviews within that state were not conducted. The interviews and supporting documentation provided by the utilities and the state regulatory agencies form the basis for the individual incentive program reports that describe the structure of each incentive program and discuss the financial effects of the programs on the utilities.

To meaningfully describe various incentive programs, this report identifies programs as belonging to one of the three primary classes: nuclear performance incentive programs, utility performance standard programs, and utility economic incentive programs. For a program to be classified as a nuclear performance incentive program, it must have two defining characteristics: it must include specified nuclear performance standards, and it must link the standards to specified, predetermined revenue adjustments.

Utility performance standard programs and utility economic incentive programs are state regulatory programs that frequently have one of the two defining characteristics of a nuclear performance incentive program. Utility performance standard programs make use of either a nuclear or a utility performance standard to determine the prudency or reasonableness of operations. The state regulatory agency, in turn, subjectively determines revenue adjustments based on prudency or reasonableness. Thus, utility performance standard programs are not directly linked to predetermined rewards or penalties, but are useful in determining allowed recovery of fuel costs. Utility economic incentive programs are included because such programs provide specified revenue adjustments that are not directly linked to generating asset performance, but are based on a utility efficiency parameter, such as total fuel costs.

2.0 INDIVIDUAL REPORTS GROUPED BY STATE REGULATORY AUTHORITY

The individual reports discuss each incentive program implemented by state regulatory agencies and the affected utilities. The reports are organized alphabetically by state; the incentive program classification appears on the top of the page. Individual reports identify state regulator, applicable utilities, program status, performance criterion, and type of incentive program. Reports include a detailed description of the programs followed by a discussion of the available financial impact data.

The incentive program classification specifies the class of program or identifies programs with unique characteristics. The identification of the utilities includes a list of each utility's nuclear units that are affected by the program and the amount of the utility's investment in each unit. Program status indicates the effective date of a program's implementation, the date measurement of performance actually began. Type of incentive program refers to how revenue adjustments are made; for example, the use of rewards or penalties for nuclear performance incentive programs.

Program descriptions address the specific provisions of each program including the program's goal or purpose, the development of the program, the jurisdictional authority of a state, the applicable units, and any minor investors. The measure of performance, performance periods, target performance, and specified revenue adjustments are discussed in this section. This section also includes a description of unique program characteristics and any recent activity regarding the incentive program. The financial impact data sections are primarily devoted to reporting the revenue adjustments a utility has experienced as a function of performance and may include information regarding current or projected performance.

There are a number of terms or features referenced within an individual report that are common to many programs. Capacity factor, a frequent measure of performance, refers to the maximum dependable capacity unless otherwise stated. Revenue adjustments refer to rewards, penalties, disallowances, or other economic sanctions. There are programs that use an escalating technique to calculate rewards or penalties. These programs specify different rewards or penalties for performance ranges above or below a certain value. For example, a program may have a relatively low penalty for the first 10% range below target capacity; the second 10% range below capacity may have a higher penalty. Total revenue adjustment is calculated by determining the penalties associated with performance within each range and adding these values together.

2.1 ARIZONA

Construction Cost Cap

Arizona Corporation Commission

Arizona Public Service: Palo Verde 1, 2, and 3, 29.1%

Program Status: Initiated November 1984.

Performance Criterion: Total Costs.

Type of Incentive Program: Exclusion of Excess Costs from Rate Base.

Description: The Arizona Corporation Commission (ACC) applied a $2.86 billion construction cost cap to Arizona Public Service Company's (APS) share of all three Palo Verde units; there are no unit-by-unit cost caps. Amounts expended above the cap will be presumed to have been imprudently incurred. The burden of proving the prudency of any excess cost is on APS. Any plant investments that are determined to be imprudent by the ACC are excluded from rate base.

The total construction cost of Palo Verde 1, 2, and 3 was $5.9 billion (excluding allowed funds used during construction). Of the total construction cost, 29.1% is to be borne by APS. The prudence of APS's investment is currently under review by the ACC and a decision is expected in 1991. At this time, it appears that APS's construction expenses have fallen within the cost cap.

Financial Impact Data: Under proposed new accounting procedures being considered, a $10 million imprudent plant investment in Palo Verde would be absorbed immediately by the company and, therefore, would reduce net income by $10 million. However, under current accounting procedures, a disallowance would be amortized over a number of years. APS estimates that a $10 million imprudent plant investment in Palo Verde would reduce net income by about $1.2 million annually.

2.2 <u>ARKANSAS</u>

Arkansas Public Service Commission

Arkansas Power and Light: Arkansas Nuclear Units 1 and 2, 100%

<u>Program Status:</u> Effective January 1980; revised January 1983.

<u>Performance Criterion</u>: Capacity Factor.

<u>Type of Incentive Program</u>: Reward and Penalty.

<u>Description</u>: In June 1980, the Arkansas Public Service Commission established a nuclear performance incentive program to partially insulate ratepayers from replacement fuel costs that could result from unplanned outages of Arkansas Nuclear Units 1 and 2. The program was modified in 1983. The program's initial target capacity factor (approximately 79%) was adjusted within the first few months to consider downtime for post-Three Mile Island improvements. The target capacity factors (± 2.5%) were reset at 72.92% for Unit 1 and 71.55% for Unit 2. The revised targets were reported to be based on industry data for similar units and are currently in use.

Prior to the 1983 modification, there was a 100% disallowance for each consecutive 30 days of outage (other than for refueling). The program was revised to apply a 100% penalty for such an outage only once during any 12-month period. Before the program was modified, Arkansas Power and Light incurred large penalties. The utility viewed the program as weighted toward penalties with little chance of earning rewards. Consequently, plant operating decisions were carefully weighed to assure that the monetary pressures of the performance incentive did not obscure safety concerns.

The 1983 revisions to the program also provide for penalties if a nuclear unit falls below the target capacity factor. For the first cumulative 30 days of an outage (due to reasons other than refueling) during the 12-month period of performance, 100% of the net replacement fuel costs is disallowed . An additional 10% of the replacement fuel costs are disallowed for all subsequent days of non-refueling outages during the same 12-month period. Rewards equal to the fuel cost savings are accrued when a nuclear unit exceeds the target capacity factor. The Arkansas nuclear units recently have been earning rewards under this program.

There may be changes in the incentive program in the near future as the program has not been modified since 1983 and may too easily permit the utility to earn rewards. In addition, Entergy Corporation has recently taken over control of nuclear operations and it is not clear that an incentive program that is directed at the utility will continue to have the intended affect.

<u>Financial Impact Data</u>: Rewards and penalties are calculated monthly, based on nuclear performance for the 12-month period ending with the current month. Potential penalties range from zero to the actual cost of replacement fuel: 100% for the first 30 days of outage and 10% thereafter. The range of rewards is smaller, equal to fuel savings earned from higher than required

capacity factors. In the current period, Arkansas Power and Light has accumulated a $5,070,000 reward based on nuclear performance from January through June 1990. The annual cumulative rewards and penalties since 1980 are reported in Table 2.1, Arkansas Power and Light's Revenue Adjustments: 1980 -1989.

TABLE 2.1. Arkansas Power and Light's Revenue Adjustments: 1980-1989

Period	$Reward ($Penalty)
1980	(17,684,000)
1981	(9,869,000)
1982	(30,545,000)
1983	(37,271,000)
1984	(18,906,000)
1985	(9,986,000)
1986	(9,091,000)
1987	(4,837,000)
1988	427,000
1989	480,000

2.3 CALIFORNIA

California Public Utility Commission

Pacific Gas and Electric: Diablo Canyon 1 and 2, 100%

Program Status: Effective July 1988.

Performance Criteria: Generation and Expenses.

Type of Incentive Program: Generation determines revenues.

Description: The Target Capacity Factor Incentive Program approved for Diablo Canyon was discontinued after the July 1988 settlement was approved. The Diablo Canyon settlement has not changed in substance since it was approved by the Commission. The California Supreme Court has declined to review the settlement decision. Diablo Canyon revenues are strictly a function of generation and are based on a price per kilowatt determined by the California PUC. This program is referred to as Performance Based Revenues (Pricing). Although Pacific Gas and Electric (PG&E) owns Diablo Canyon, Diablo Canyon's revenues are considered to be distinct from PG&E: the units are not in rate base or regulated as are other California nuclear units. PG&E is also perceived to be the consumer of Diablo Canyon's generation, generation that is purchased at specified rates per kilowatt hour. The rate per kilowatt hour will increase each year through 1994 according to a specified, escalating price. Subsequent rate increases will then be tied to the Consumer Price Index. The settlement stipulates that the performance of Diablo Canyon is not to be a factor in the PUC's authorized rate of return for PG&E.

Development of the Diablo Canyon settlement was initiated at the request of the Commission in the course of an interim rate relief procedure. PG&E was amenable to the settlement as it would avoid protracted ligation in a prudency review of construction costs. The prevailing opposition to the nuclear units in 1988 suggested that a settlement was needed. The settlement, submitted by PG&E, the Commission's Division of Ratepayer Advocates, and the Attorney General, resolved the original, disputed plant construction costs.

California does not permit ~ utility to recover capital construction costs through rates until a is operational. However, if requested, the Major Addition Adjustment C ermits the revenue required to recover capital costs to be treated as erred debit until the completion of the project. As part of the settlemen G&E gave up rights to collect over $2 billion in balancing account revenues (the deferred debit) that had been previously accrued. The settlement became effective in July 1988, and if the unit operates at the national average capacity factor (58% in 1987), the settlement will equal $2 billion in rate base disallowance.

Two other issues of the settlement concern the establishment of an independent safety committee to monitor the units' performance and the allocation of Diablo Canyon's costs. To date, two of the three committee members have been selected from the candidates nominated by PG&E, the PUC, and the University of California's Dea- f Engineering. The PUC and PG&E will address the methods and procedures to be used in the allocation of common costs between PG&E and Diablo Canyon in late 1990.

The utility has observed that the Performance Based Revenues program has been a strong incentive for operating safely and efficiently. Safety is a significant priority at Diablo Canyon. The program is believed to be a positive change and is expected to favorably impact the industry, utility, and customers. The settlement is intended to provide the ratepayer protection from nuclear units that fail to generate, and from escalating costs of operation and capital improvements. In return, PG&E has the opportunity to recover the full cost of the facility should the Diablo Canyon units perform at capacity factors in excess of the national average.

With respect to the conduct of operations at Diablo Canyon since the settlement became effective, the units' preventative maintenance and inventory of spare parts have assumed a high priority with utility management. The risks of poor management are high enough to preclude ineffective operations. The utility's prevailing philosophy is such that conditions that could potentially inhibit safe operations and, over time, degrade long-term performance act as an incentive to bring the units down for maintenance rather than continue operations in less than optimal circumstances. Ineffective operation of Diablo Canyon would be considered an abuse of the settlement. PG&E reports that Diablo Canyon has experienced a 20-25% increase in operating and maintenance budgets in the period since the settlement became effective.

Financial Impact Data: Prior to discontinuing the Target Capacity Factor Incentive Program at Diablo Canyon, the utility earned a $14 million reward as a result of an 88% capacity factor attributable to Unit 1 in the 12-month period ending May 1986. This period did not include a refueling outage. For Unit 2 and the performance measured over a single cycle (ending July 1987), a capacity factor of 66% (within the established deadband) neither incurred a penalty nor earned a reward.

It should be noted that with traditional rate-making techniques, utility revenues decrease over time. However, as the structure of the Diablo Canyon settlement provides for increases in kilowatt prices, revenues are expected to increase over time. In the event the utility is placed in a position to abandon Diablo Canyon due to poor performance, the settlement entitles Diablo Canyon to request recovery of a portion of PG&E's investment. For example, the maximum recovery in 1990 would equal $2.8 billion.

Recent Diablo Canyon performance has been good and current revenues are higher than originally anticipated. Based on forecasted levels of performance, revenues resulting from Performance Based Revenues (Pricing) are expected to begin to equal revenues of traditional rate making in 1996. PG&E perceives the settlement to be equitable, based on their long-range projections. Diablo Canyon performance to date is shown in Table 2.2, Diablo Canyon Performance Since Implementation of Performance Based Revenues.

TABLE 2.2. Diablo Canyon Performance Since Implementation of Performance Based Revenues

Unit	Fuel Cycle	Capacity Factor
Diablo Canyon 1	Cycle 1	68%
	Cycle 2	66%
	Cycle 3	82%
Diablo Canyon 2	Cycle 1	66%
	Cycle 2	72%
	Cycle 3	81%

2.4 CALIFORNIA

California Public Utility Commission

Southern California Edison: San Onofre (SONGS) 1, 80%
SONGS 2 and 3, 20%
Palo Verde 1, 2, and 3, 15.8%

San Diego Gas and Electric: San Onofre (SONGS) 1, 2, and 3, 20%

Program Status: SONGS 1 effective July 1986.
SONGS 2 effective September 1983.
SONGS 3 effective April 1984.
Palo Verde 1 effective February 1986.
Palo Verde 2 effective September 1986.
Palo Verde 3 effective January 1988.

Performance Criterion: Capacity Factor.

Type of Incentive Program: Reward and Penalty.

Description: The Target Capacity Factor Incentive Program is applied to Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E). Designed to be a risk-sharing mechanism for the utility and the ratepayer, the program also serves to encourage efficient utility management. Performance, in terms of capacity factor, is measured over the unit's fuel cycle (approximately 18 months). The established deadband for SONGS 1 is from 55% to 75%; for SONGS 2 and 3, the deadband ranges from 55% to 80%. At capacity factors above the deadband, the utility reward is equal to 50% of the fuel cost savings; at capacity factors below 55%, the utility incurs a penalty equal to 50% of the replacement fuel costs. Capacity factor, however, is calculated separately for each utility. The corresponding reward or penalty is based on each utilities' replacement power costs and implemented through the Energy Cost Adjustment Clause. In addition, the program provides for economic modifiers that would mitigate a penalty for operating at reduced capacity when in the interests of the ratepayer. Economic modifiers may be applied when a utility can purchase power at a lower rate or extend the operating period in order to continue to supply ratepayers in peak periods.

While the program functions for the most part in lieu of routine prudency reviews, the reasonableness of operations are always subject to review. The California PUC has the authority to conduct a prudency review in the event of a forced outage and may, as it has in the past, deny recovery of replacement fuel costs associated with an outage. Further, the California PUC is obligated by California law to review any outage that extends more than nine months. Additional disallowances based on prudency reviews have the potential to become a drawback to the program. However, once a penalty is imposed upon a utility for a nuclear unit's performance within a given period, a review of an outage occurring in that period is not usually conducted.

Generally, performance of the SONGS units has been good and the units have not experienced a significant outage in recent years. SCE reports that while the

Target Capacity Factor Incentive Program receives significant attention from the public, both good and bad, the revenue impact on the utility is quite small. Nonetheless, utility management is attentive to the units' performance due to the visibility of the program. On the site level, the safety of SONGS is not impacted; site operations are not managed or tailored to the target capacity factor.

At this time, a proposal is before the California PUC to revise the current Target Capacity Factor Incentive Program. The proposal seeks to establish a three-cycle period of performance, a 55% to 75% deadband range, and to include additional economic modifiers. The three-cycle average would reduce the capacity factor variation which occurs from cycle to cycle. The currently employed economic modifiers mitigate penalties under specified conditions; the additional economic modifiers would provide rewards in specified reduced capacity conditions.

Financial Impact upon Southern California Edison: The reported capacity factor of SONGS 3 for Cycle 1 (54.6%) was due in part to extended operation of the unit at reduced capacity to support peak summer power demands. As a result, SCE's penalty was partially mitigated as provided for by the economic modifiers that allow the unit to remain online when advantageous to the ratepayer, as was the case in this instance. The California PUC has yet to rule on the reported Cycle 4 capacity factor for SONGS 2; this fuel cycle falls within the deadband. The utility has yet to formally report the Cycle 4 capacity factor for SONGS 3, but the capacity factor is expected to fall within the deadband. The extended outages experienced by Palo Verde 1 (March 1989 - July 1990) and Palo Verde 2 (March 1989 - present) are currently under review by the California PUC. For SONGS 1, Cycle 10 is forecast to conclude in December 1990 and performance for this cycle is forecast to yield a penalty. For SONGS 2 and 3, Cycle 5 is forecast to conclude in July 1991 and January 1992, respectively, at deadband performance levels. Table 2.3, Southern California Edison's Revenue Adjustments as Determined by Capacity Factor, shows the performance and corresponding revenue impact of each of SCE's nuclear units subject to the Target Capacity Factor Incentive Program.

Financial Impact upon San Diego Gas and Electric: SDG&E's reported capacity factor Cycle 1 at SONGS 3 (59.2%) was higher than that reported for SCE (54.6%). Late in Cycle 1, SCE continued to operate SONGS 3 at a reduced capacity rather that shut down as scheduled in order to support peak summer power demands. However, SCE continued to supply SDG&E with their generation requirements, resulting in a capacity factor higher than that reported for SCE. The utility expects to accrue a penalty for SONGS 3's current cycle performance, as a mid-cycle outage for substantial repairs is scheduled for June 1990 through December 1990. For SONGS 2 and 3, Cycle 5 is forecast to conclude in July 1991 and January 1992, respectively, at deadband performance levels. The performance and corresponding revenue impact of each of SDG&E's nuclear units subject to the Target Capacity Factor Incentive Program is shown in Table 2.4, San Diego Gas and Electric's Revenue Adjustments as Determined by Capacity Factor.

TABLE 2.3. Southern California Edison's Revenue Adjustments as Determined by Capacity Factor

UNIT Effective Date	Fuel Cycle	Month/ Year		Month/ Year	Capacity Factor	$Reward ($Penalty)
SONGS 1	Cycle 9	7/86	-	4/89	55.1%	0
July 1986	Cycle 10	4/89	-	12/90	--	--
SONGS 2	Cycle 1	8/83	-	2/85	55.5%	0
September 1983	Cycle 2	2/85	-	5/86	57.0%	0
	Cycle 3	5/86	-	10/87	81.7%	1.3 million
	Cycle 4	10/87	-	11/89	72.3%	0
SONGS 3	Cycle 1	4/84	-	11/85	54.6%	(560,000)
April 1984	Cycle 2	11/85	-	2/87	56.2%	0
	Cycle 3	2/87	-	7/88	80.6%	400,000
	Cycle 4	7/88	-	7/90	--	--
PALO VERDE 1	Cycle 1	2/86	-	12/87	55.4%	0
February 1986	Cycle 2	12/87	-	2/90	37.3%	(5.3 million)
PALO VERDE 2	Cycle 1	9/86	-	6/88	67.0%	0
September 1986	Cycle 2	6/88	-	6/90	--	--
PALO VERDE 3	Cycle 1	1/88	-	10/89	58.3%	0
January 1988						

TABLE 2.4. San Diego Gas and Electric's Revenue Adjustments as Determined by Capacity Factor

UNIT Effective Date	Fuel Cycle	Month/ Year		Month/ Year	Capacity Factor	$Reward ($Penalty)
SONGS 1	Cycle 9	7/86	-	4/89	55.1%	0
July 1986	Cycle 10	4/89	-	12/90	--	--
SONGS 2	Cycle 1	8/83	-	2/85	55.5%	0
September 1983	Cycle 2	2/85	-	5/86	57.0%	0
	Cycle 3	5/86	-	10/87	81.7%	353,000
	Cycle 4	10/87	-	11/89	72.3%	0
SONGS 3	Cycle 1	4/84	-	11/85	59.2%	0
April 1984	Cycle 2	11/85	-	2/87	56.2%	0
	Cycle 3	2/87	-	7/88	80.6%	134,000
	Cycle 4	7/88	-	7/90	--	--

2.5 CONNECTICUT

Connecticut Department of Public Utility Control

Connecticut Light and Power: Millstone 1 and 2, 81%
(Northeast Utilities) Millstone 3, 53%
Connecticut Yankee, 34.5%

Program Status: Effective July 1979.

Performance Criterion: Capacity Factor.

Type of Incentive Program: Subjective denial of replacement fuel costs.

Description: Connecticut Light and Power's (CL&P) investment in Connecticut nuclear units is subject to the provisions of the Generation Utilization Adjustment Clause (GUAC) and the regulatory authority of the Connecticut Department of Public Utility Control (DPUC). However, while CL&P's investment in Massachusetts Yankee (24.5%), Vermont Yankee (9.5%), and Maine Yankee (12%) is not subject to the Connecticut DPUC's regulation, they contribute to the composite capacity measured by the GUAC. GUAC treatment and application of performance standards to the nuclear units occurs at the request of the utility. United Illuminating, a Connecticut utility with an investment in Seabrook (NH), Connecticut Yankee (CT), and Millstone 3 (CT), is not effected.

The GUAC's purpose is to recover (refund) the difference between fossil and nuclear fuel costs at base rate levels for replacement of nuclear kilowatts below (above) 70% of nuclear capacity. Fuel costs are set, based on projections for the coming period. The GUAC provides the utility with credit for projected replacement fuel costs based on the assumed level of performance. The deferred amount is accumulated for twelve months ending July and amortized over the following eleven months (September - July). Each year, the previous year's replacement fuel costs are reviewed and adjusted. The GUAC allows for collection of higher actual costs incurred; ratepayer refunds are required for lower actual costs.

At a capacity factor below 55%, the utility possibly may not recover replacement fuel costs. However, criterion performance does not preclude disallowance of GUAC credit for replacement fuel costs due to unit outages. Reviews of individual outages are conducted in the annual GUAC billing rate filing.

CL&P's most recent rate case was conducted prior to Seabrook's (NH) commercial operation. A rate case is scheduled for December 1990, at which time, Seabrook will become a factor in CL&P's composite capacity factor. In addition, the purchase of Public Service Company of New Hampshire by Northeast Utilities is currently under review by the Federal Energy Regulatory Commission. The purchase would increase Northeast Utilities' investment to approximately 40%, consequently Seabrook's contribution to CL&P's capacity factor would also increase.

Financial Impact Data: Since the program's implementation, replacement fuel costs have not been denied due to the difference between the assumed capacity factor of the GUAC and the actual composite capacity factor achieved by the nuclear units. Rather, the GUAC functions as a fuel adjustment clause. The 1986 disallowance of replacement fuel costs ($115,000) associated with a Connecticut Yankee power supply outage was the result of a prudency review and was not directly determined by the GUAC. The composite performance for the CL&P nuclear units since the GUAC became effective is listed in Table 2.5, Composite Performance of Connecticut Light and Power's Nuclear Units.

Currently, the potential for a GUAC credit disallowance exists due to the extended outage of the Connecticut Yankee unit. The unit's September 2, 1989, outage began when the unit went down for a scheduled refueling. At that time, it was determined that repairs to the thermal shield during the previous refueling outage were inadequate and that the repair debris had damaged the reactor. The removal of the thermal shield and the reactor repairs extended the 1989 refueling outage. The Connecticut DPUC is expected to hold hearings regarding the Connecticut Yankee outage in conjunction with the annual GUAC billing rate filing.

TABLE 2.5. Composite Performance of Connecticut Light and Power's Nuclear Units

Period Month/Year-Month/Year	Composite Capacity Factor
8/84 - 7/85	73.7%
8/85 - 7/86	74.1%
8/86 - 7/87	74.5%
8/87 - 7/88	72.1%
8/88 - 7/89	74.7%

2.6 FLORIDA

Florida Public Service Commission

Florida Power: Crystal River 3, 90%

Florida Power and Light: St. Lucie 1, 100%
St. Lucie 2, 85.1%
Turkey Point 3 and 4, 100%

Program Status: Effective September 1980.

Performance Criteria: Equivalent Availability and Heat Rate.

Type of Incentive Program: Reward and Penalty.

Description: The Generating Performance Incentive Factors (GPIF) program goal is to minimize fuel costs and purchased power costs, and to provide an incentive for the efficient operation of base load generating units (both nuclear and fossil). The GPIF program calculates performance over six-month fuel adjustment periods. The generating units included in a utility's GPIF calculation are those units that contribute at least 80% of the estimated total system net generation for the performance period. During any given period, however, one or more generating units may need to be omitted from the GPIF calculation even though the units may meet the general selection criteria. The Florida Public Service Commission (PSC) has the authority to determine, on a case-by-case basis, whether a unit should be excluded from the calculation of the GPIF.

Six-month equivalent availability and average heat rate performance targets are set for each unit. Equivalent availability and heat rate for each unit are averaged on a three-year rolling basis. These averages form the basis for the PSC to evaluate the reasonableness of proposed GPIF performance targets. Target values for the most recent periods of performance for each nuclear unit are indicated in Table 2.6, Generating Performance Incentive Factors (GPIF) Program: 1989 - 1991 Target Values.

At the conclusion of the six-month fuel adjustment periods, actual unit equivalent availability and average heat rates are compared to the pre-established targets. Based on this comparison, a monetary reward is awarded for performance above the targets; a monetary penalty is incurred for performance below the targets. A production cost modeling program is used to determine replacement power costs or savings. Penalties or rewards incurred as a function of unit performance are implemented through the fuel and purchased power cost recovery clause. The maximum reward or penalty for a utility's period of performance is 50% of the maximum allowed incentive dollars. The maximum allowed incentive dollars are determined according to the following formula:

$$\frac{\text{(Average month balance of common equity for the period) (25 basis points)}}{\text{Revenue expansion factor}}$$

TABLE 2.6. Generating Performance Incentive Factors (GPIF) Program: 1989-1991 Target Values

Unit	Period	Equivalent Availability Target	Heat Rate Target
Crystal River 3	Winter 89/90	61.7%	10,482
	Summer 90	49.7%	10,592
	Winter 90/91	75.5%	10,373
Turkey Point 3	Winter 89/90	55.9%	10,882
	Summer 90	43.5%	11,110
	Winter 90/91	31.9%	10,868
Turkey Point 4	Winter 89/90	76.0%	10,847
	Summer 90	74.4%	11,104
	Winter 90/91	18.1%	10,873
St. Lucie 1	Winter 89/90	63.3%	10,729
	Summer 90	85.9%	10,760
	Winter 90/91	92.5%	10,671
St. Lucie 2	Winter 89/90	95.6%	10,726
	Summer 90	79.5%	10,835
	Winter 90/91	77.2%	10,734

An adjustment is made to the value obtained from this formula for jurisdictional sales. The maximum allowed incentive dollars is not to exceed the gross amount of any fuel savings or costs experienced during the period under evaluation.

<u>Financial Impact upon Florida Power</u>: Table 2.7, GPIF Rewards and Penalties for Florida Power's Crystal River, lists the revenue adjustments for each six-month performance period since the Winter of 1980/81. The utility indicates that penalties beginning in the Summer 85 period were caused primarily by a refueling outage that extended from July through August, and by the subsequent limited availability of the unit. A forced outage from January 1986 through June 1986 contributed to the Winter 85/86 penalty. Crystal River 3 was temporarily removed from the program in the Summer 86 period because of a six-month outage to repair a coolant pump shaft. Two forced outages related to failure of the reactor coolant pump seal resulted in the Winter 86/87 period penalty.

<u>Financial Impact upon Florida Power and Light</u>: Table 2.8, GPIF Rewards and Penalties for Florida Power and Light's Nuclear Units, lists the revenue adjustments for each six-month performance period since the Summer of 1981. The utility indicates that the penalties incurred in the Summer 87 period and the Winter 87/88 period were attributable to the reduced availability of the Turkey Point units.

TABLE 2.7. GPIF Rewards and Penalties for Florida Power's Crystal River

Period	$ Reward ($Penalty)
Winter 80/81	272,000
Summer 81	(273,000)
Winter 81/82	(692,000)
Summer 82	356,000
Winter 82/83	(491,000)
Summer 83	(401,000)
Winter 83/84	680,000
Summer 84	540,000
Winter 84/85	720,000
Summer 85	(509,000)
Winter 85/86	(820,000)
Summer 86	N/A
Winter 86/87	(192,000)
Summer 87	313,000
Winter 87/88	675,000
Summer 88	992,000
Winter 88/89	(1,129,000)
Summer 89	(866,000)
Winter 89/90	710,000

TABLE 2.8. GPIF Rewards and Penalties for Florida Power and Light's Nuclear Units

Period	$ Reward ($ Penalty)
Summer 81	509,000
Winter 81/82	520,000
Summer 82	116,000
Winter 82/83	2,099,000
Summer 83	(38,000)
Winter 83/84	(2,142,000)
Summer 84	(1,904,000)
Winter 84/85	(2,050,000)
Summer 85	435,000
Winter 85/86	2,287,000
Summer 86	(33,000)
Winter 86/87	1,907,000
Summer 87	(606,000)
Winter 87/88	(1,232,000)
Summer 88	1,194,000
Winter 88/89	(733,000)
Summer 89	(2,561,000)
Winter 89/90	1,587,000

2.7 GEORGIA

Georgia Public Service Commission

Georgia Power: Hatch 1 and 2, 50.1%
Vogtle 1 and 2, 45.7%

Program Status: Effective January 1990.

Performance Criterion: Capacity Factor.

Type of Incentive Program: Reward and Penalty.

Description: The purpose of the nuclear performance incentive program is to provide equitable sharing between ratepayers and Georgia Power. Ratepayers and the utility are intended to share either the benefits derived from efficient operation or the excess cost associated with inefficient operation of nuclear generating assets. The Georgia Public Service Commission's (PSC) position is that a nuclear performance incentive program is a reasonable means of providing some assurance to the ratepayers that the utility will be held accountable for its fair share of any additional future costs resulting from poor performance of the Hatch and Vogtle units.

The measure of performance for the Georgia Power nuclear units is the composite, three-year capacity factor. Performance evaluations will be conducted at the conclusion of a three-year period. The target capacity factor chosen for each unit will be based on an average capacity factor for all comparable U.S. units that operated at an average capacity of 50% or higher during the three-year period. The deadband will be equal to target capacity factor ±4%. Rewards or penalties will be equal to 50% of the savings (or costs) determined by the difference between actual performance and target performance. The standards specify that the maximum potential penalty is not to exceed the maximum potential reward. Revenue adjustments (rewards or penalties) will be implemented as required through the fuel cost recovery mechanism.

The standards are to function in lieu of routine, individual outage reviews that currently address replacement fuel costs. However, the order establishing the nuclear performance standards provides the Georgia PSC with flexibility, so that in the appropriate circumstances, any unit may be excluded from consideration under the performance incentive program for the purpose of performing a separate prudence evaluation. A unit that operates with an average capacity factor below 50% for the period of performance will be excluded from the program and considered for a detailed operating prudence review by the PSC. Georgia Power may also request that the PSC exclude a unit from the program in the case of unusual, or extraordinary circumstances.

Financial Impact Data: The potential revenue impact is difficult to estimate due to the brief period of time that the program has been in effect. In addition, the target capacity factor, based on the average performance of comparable units during 1990 - 1992, has not yet been determined. Performance of the Georgia Power units since 1985 is shown in the Table 2.9, Georgia Power's Nuclear Unit Performance: 1985 - 1989.

TABLE 2.9. Georgia Power's Nuclear Unit Performance: 1985-1989

Unit	Period	Capacity Factor
Hatch 1	1985	72.20%
	1986	53.94%
	1987	77.27%
	1988	61.85%
	1989	97.71%
Hatch 2	1985	82.05%
	1986	53.06%
	1987	86.34%
	1988	63.02%
	1989	61.52%
Vogtle 1	1987	71.61%
	1988	71.65%
	1989	91.80%
Vogtle 2	1989	94.59%

2.8 ILLINOIS Rescinded Incentive Program

Illinois Commerce Commission

Commonwealth Edison: Dresden 2 and 3, 100%
LaSalle County 1 and 2, 100%
Zion 1 and 2, 100%
Bryon 1 and 2, 100%
Braidwood 1 and 2, 100%
Quad Cities 1 and 2, 75%
Carroll County, 66.3%

Program Status: 1988 Agreement rescinded December 1989.

Performance Criterion: Total Fuel Cost.

Type of Incentive Program: Reward.

Description: Illinois has not adopted a nuclear performance standard program to date. However, the 1988 Commonwealth Edison agreement with the Illinois Commerce Commission (ICC) modified the fuel clause to include a financial incentive to improve performance. The agreement, a utility economic incentive program, specified that of the total system, annual fuel cost, 50% of the amount below the calculated average cost would accrue to the utility. The agreement was remanded back to the ICC in December 1989 by the State Supreme Court; thus, the agreement is considered to be null and void. Currently, utility prudency with respect to unit outages and associated replacement fuel costs are addressed in the annual fuel reconciliation proceeding. 100% of fuel cost savings and prudently incurred replacement fuel costs are passed to the ratepayer.

The Illinois Commerce Commission's rate order for Illinois Power requested that the ICC staff examine the performance standards applicable to nuclear generating stations. The recommendations of the staff report have the potential to effect Commonwealth Edison.

Maryland Public Service Commission

Baltimore Gas and Electric: Calvert Cliffs 1 and 2, 100%

Program Status: Effective January 1988.

Performance Criterion: Capacity Factor.

Type of Incentive Program: Subjective denial of replacement fuel costs.

Description: The Maryland Public Service Commission (PSC) permits recovery of increased fuel costs through the fuel rate only to the extent that the utility has maintained a reasonable production level at all of its generating assets. The Commission determined that the Generating Unit Performance Program (GUPP), a system-wide measure, constitutes an initial analysis of the reasonableness of a utility's performance. A utility that demonstrates that its actual system wide performance meets or exceeds the determined target is considered to have maintained a reasonable production level at all of its assets. If the utility's system-wide performance falls short of the target, each asset's target and actual performance are examined and the utility is required to demonstrate that the outages associated with the poor performance were not due to utility imprudence. Even though meeting both the system-wide target and each asset's target is considered reasonable performance, individual outage reviews may still be conducted. Outage and poor performance reviews are consistent with the subjective reviews conducted in prior fuel rate proceedings that denied the utility replacement fuel costs incurred at Calvert Cliffs.

The GUPP provides the basis to determine a reasonable production level. The annual target capacity factor, for individual nuclear units and the generating system as a whole, is based on a statistical analysis of the performance of similar nuclear units and generating systems. Performance is measured each calendar year. Actual utility performance for the past calendar year is reviewed in the annual fuel rate proceeding. The performance targets for the next two years are determined in a biannual January proceeding.

Financial Impact Data: Recovery of replacement fuel costs are not determined by performance standards but are addressed in the course of an individual outage review. Historically, approximately 50% of replacement fuel costs incurred due to imprudency on the part of the utility have been disallowed. Performance of the Calvert Cliffs units since the GUPP was implemented is shown in Table 2.10, Target and Adjusted Actual Capacity Factor of Baltimore Gas and Electric's Nuclear Units. The May 1989 outage for both Calvert Cliffs' units is expected to be extended until the end of 1990 for Unit 2; plans are underway to return Unit 1 to service in the near future. The actual capacity factor determined for a given period of performance is adjusted for planned outages; however, the GUPP does not include a precise definition of a planned outage or an unplanned outage. At issue is the 1989 adjusted actual capacity. In contrast to the utility's assertion, the Maryland PSC staff views the current outage as unplanned.

TABLE 2.10. Target and Adjusted Actual Capacity Factor of Baltimore Gas and Electric's Nuclear Units

Period	Unit	Capacity Factor Target	Capacity Factor Adjusted Actual
1988	Calvert Cliffs 1	52.71%	81.55%
	Calvert Cliffs 2	58.36%	85.33%
1989	Calvert Cliffs 1	60.69%	14.31%
	Calvert Cliffs 2	66.79%	85.81%
1990	Calvert Cliffs 1	59.37%	--
	Calvert Cliffs 2	65.20%	--

Massachusetts Department of Public Utilities

Boston Edison: Pilgrim, 100%

Program Status: Effective November 1989.

Performance Criteria: Capacity Factor, Performance Indicators, and Systematic Assessment of Licensee Performance (SALP) Rating.

Type of Incentive Program: Reward and Penalty.

Description: The settlement agreement of November 1989 resolved three cases before the Massachusetts Department of Public Utilities (DPU): the rate case filed by Boston Edison; a petition to remove Pilgrim from rate base; and $250 million in replacement fuel costs. The settlement was proposed and agreed to by Boston Edison and the various intervenors. The Massachusetts DPU accepted the settlement, as it was consistent with the interests of the ratepayers. Under the terms of the settlement, Boston Edison withdrew a request for an 8.4% ($86 million) rate increase and wrote off $101 million in operating and maintenance expenses incurred during Pilgrim's 33-month outage. Boston Edison is precluded from filing a new rate case until 1992; however, the utility's rates will change in the interim in accordance with the performance adjustment factor.

The settlement imposes an incentive program upon Pilgrim which adjusts the utility's revenues up or down based on Pilgrim's performance. The performance measures of the incentive program consist of the annual capacity factor, a set of performance indicators, and the unit's latest Systematic Assessment of Licensee Performance (SALP) rating. Boston Edison can be penalized $1 million for each 1% that Pilgrim operates below a 60% capacity factor. The utility will be awarded $1 million for each 1% above a 76% capacity factor, up to $15 million annually. For each of five performance indicators (safety system failures, collective radiation exposure, automatic scrams while critical, safety system actuations, and maintenance backlog) the utility could earn as much as $300,000 or be penalized $600,000. Criterion performance for automatic scrams while critical, safety system failures, and safety system actuation is defined by the NRC average. The collective radiation exposure criteria is defined as the INPO median boiling water reactor value of man/rems/unit/year $\pm$ 25.0; maintenance backlog criteria is equal to the INPO average number of work orders $\pm$ 5%. In addition, based on Pilgrim's SALP rating, the utility will earn $500,000 for each one-tenth of a point below 1.6, for a maximum reward of $3 million; it will be penalized $500,000 for each one tenth of a point above 1.8, for a maximum penalty of $6 million. The performance adjustment charge for Pilgrim will be factored into the quarterly fuel charge for all Boston Edison generating assets. The fuel charge is passed on to ratepayers; thus, should Pilgrim incur a penalty, the loss of revenues to Boston Edison would be reflected in a reduced fuel charge.

Financial Impact Data: Boston Edison has indicated that the full economic impact of the incentive plan would not be measurable until the end of the current performance period. However, the maximum reward or penalty can be quantified. The annual base component element of the performance adjustment actor will incrementally increase company revenues by $20 million, $22.5 million, and $25 million in 1990, 1991, and 1992, respectively. These revenue increments are subject to adjustment in accordance with Pilgrim's performance. Performance-related adjustments for poor performance in 1990 could decrease revenues $39 million, resulting in a maximum net reduction of $19 million. Conversely, good performance could increase 1990 revenues by $19.5 million above the annual base component adjustment. Similar results could follow from applying the performance adjustment factor in 1991 and 1992. The maximum potential increase or decrease in revenues as a result of Pilgrim's performance is summarized in Table 2.11, Calculation of Maximum Revenue Adjustments for Pilgrim as a Function of Performance.

The lifetime capacity factor for Pilgrim prior to the 33-month outage was 56.8%. The projected capacity factor for the current period of performance (November 1989 - October 1990) is 71%. The reported monthly capacity factor for the unit is shown in Table 2.12, Pilgrim Capacity Factor by Month: November 1989 - May 1990. Table 2.13, Pilgrim Performance Indicators as of August 1990, shows criterion performance for each of the five indicators, Pilgrim's performance as of August 1990, and the available revenue adjustment figure. Pilgrim's most recent average SALP rating of 1.7 falls within the required range, yielding neither a penalty nor a reward.

TABLE 2.11. Calculation of Maximum Revenue Adjustments for Pilgrim as a Function of Performance Criteria

Performance Criteria	Rate of ($Penalty)	Maximum ($Penalty)	Rate of $ Reward	Maximum $ Reward
Capacity Factor	(1 million)/ percentage point	(30.0 million)	1 million/ percentage point	15.0 million
Performance Indicators	(600,000)/ indicator	(3.0 million)	300,000/ indicator	1.5 million
SALP Rating	(500,000)/ 1/10 point	(6.0 million)	500,000/ 1/10 point	3.0 million
Total Performance Adjustments		(39.0 million)		19.5 million
1990 Annual Base Component Element		20.0 million		20.0 million
Net Maximum Revenue Adjustment		(19.0 million)		49.0 million

TABLE 2.12. Pilgrim Capacity Factor by Month: November 1989-May 1990

Period Month/Year	Capacity Factor
11/89	66.0%
12/89	77.1%
1/90	99.4%
2/90	97.4%
3/90	30.0%
4/90	5.4%
5/90	77.9%

TABLE 2.13. Pilgrim Performance Indicators as of August 1990

Performance Indicators	Criterion Performance	Pilgrim Performance	\$Reward (\$Penalty) to Date
Automatic Scrams While Critical	1.85	2	0
Safety System Failures	3.37	2	0
Safety System Actuation	1.36	0	0
Collective Radiation Exposure	459	162.7	200,000
Maintenance Backlog	51	—	—

2.11 MASSACHUSETTS

Massachusetts Department of Public Utilities

Boston Edison: Pilgrim, 100%

Western Massachusetts Electric: Millstone 1 and 2, 19%
(Northeast Utilities) Millstone 3, 12%

Program Status: Effective 1981, revised 1983 and 1985.

Performance Criteria: Equivalent Availability Factor (primary measure).

Type of Incentive Program: Subjective denial of replacement fuel costs.

Description: The Massachusetts Fuel Act gives the Massachusetts Department of Public Utilities (DPU) the authority to require utilities to meet performance goals. Each generating unit under DPU jurisdiction is required to meet the Generating Unit Performance Program goals established for that unit. Massachusetts performance standards are applied to Connecticut units when a Massachusetts utility has an investment in those units. In addition to Pilgrim, Boston Edison is a minor investor in Connecticut Yankee (9.5%) and Yankee-Rowe (9.5%). Boston Edison, therefore, is subject to the provisions of the Generating Unit Performance Program for these units. Similarly, Western Massachusetts Electric, which has a 9.5% investment in Connecticut Yankee in addition to the three Millstone units, is subject to Massachusetts performance standards. However, as the DPU distinguished between major and minor units, Western Massachusetts Electric's investment in Yankee-Rowe (7%), Maine Yankee (3%), and Vermont Yankee (2.5%) is excluded.

Goals are determined and performance is measured over a 12-month period (June 1 - May 31). Goals and performance are based on a unit's equivalent availability factor (EAF) and its three-year average performance for availability and capacity factors, and forced outage and heat rates. The DPU views the EAF as the best measure of performance; the DPU places primary emphasis on this measure and applies the "85th percentile rule" when determining performance goals. That is, for each unit a like group of units is chosen and a three-year EAF is calculated. The 85th percentile unit from this group is identified, and its EAF becomes the performance goal for the selected unit.

The Department conducts two proceedings each year. The first determines the performance goals as described above. The second analyzes the past year's performance relative to that year's goals. Targets for plant efficiency are compared to the monthly plant statistics submitted by the utility to assist the DPU in determining the prudency of utility fuel expenditures. Failure of a unit to meet a performance goal results in a review of the unit's replacement fuel costs. These reviews place the utility at risk for the denial of replacement fuel costs determined by the DPU to be imprudently incurred.

Financial Impact upon Boston Edison: Boston Edison has incurred three penalties since the Generating Unit Performance Program was established in 1981. A $5.2 million penalty incurred in 1981 was due to scheduling difficulties that extended the refueling outage during structural modification to Pilgrim. In 1984, a $4.2 million penalty was related to an outage for pipe replacement and chemical decontamination. A $3 million penalty in 1986 was associated with an outage because of valve misalignment and foreign material in the standby liquid control system. The replacement fuel costs incurred in the April 12, 1986 - December 1, 1988 outage were addressed in the 1989 Pilgrim settlement. Table 2.14, Generating Unit Performance Program: 1985 - 1990 Pilgrim Goals and Actual Values, includes goals and actual performance since the program's 1985 revisions.

Financial Impact upon Western Massachusetts Electric: Fuel cost disallowances were imposed upon the utility first in 1985 and again in 1986 due to the performance of the Connecticut Yankee unit. However, the Massachusetts Department of Public Utilities has not imposed a penalty upon the Millstone units to date. Table 2.15, Generating Unit Performance Program 1986 - 1990 Millstone 1, 2, and 3 Goals and Actual Values, includes the goals and actual performance since the program's 1985 revisions. The 1990 - 1991 performance goals have been determined and are pending MDPU approval.

TABLE 2.14. Generating Unit Performance Program: 1985-1990
Pilgrim Goals and Actual Values

Period Month/Year - Month/Year		EAF - Equivalent Availability Factor	Average Three-Year Performance: Availability Factor	Capacity Factor	Forced Outage Rate	Heat Rate
11/85 - 10/86	Actual:	33.2%	35.4%	33.2%	50.8%	10276
	Goal:	67.6%	72.8%	67.6%	6.5%	10275
11/86 - 10/87	Actual:	0	0	0	0	0
	Goal:	67.6%	73.2%	67.6%	8.0%	10275
11/87 - 10/88	Actual:	0	0	0	0	0
	Goal:	69.4%	74.7%	69.4%	18.2%	10278
11/88 - 10/89	Actual:	32.4%	50.2%	17.1%	28.0%	11384
	Goal:	79.2%	83.1%	79.2%	16.7%	10278
11/89 - 10/90	Actual:	--	--	--	--	--
	Goal:	71.9%	75.8%	71.9%	18.0%	10278

TABLE 2.15. Generating Unit Performance Program: 1986-1990 Millstone 1, 2, and 3 Goals and Actual Values

			Average Three Year Performance:			
Period Month/Year - Month/Year		EAF - Equivalent Availability Factor	Availability Factor	Capacity Factor	Forced Outage Rate	Heat Rate
MILLSTONE 1						
6/86 - 5/87	Actual:	92.9%	95.6%	92.9%	4.4%	10518
	Goal:	64.6%	68.9%	64.6%	8.0%	10510
6/87 - 5/88	Actual:	75.9%	77.9%	75.9%	2.4%	10455
	Goal:	68.1%	73.2%	68.1%	3.9%	10513
6/88 - 5/89	Actual:	81.8%	84.2%	81.9%	2.7%	10481
	Goal:	68.7%	72.0%	68.7%	3.6%	10463
6/89 - 5/90	Actual:	92.7%	95.8%	92.9%	3.4%	10431
	Goal:	67.2%	70.5%	67.2%	3.6%	10463
MILLSTONE 2						
6/86 - 5/87	Actual:	64.3%	67.9%	64.5%	9.8%	10878
	Goal:	76.8%	80.9%	76.8%	9.0%	10944
6/87 - 5/88	Actual:	75.6%	78.9%	75.6%	8.0%	10818
	Goal:	79.6%	84.3%	79.6%	9.9%	10951
6/88 - 5/89	Actual:	71.9%	73.8%	71.9%	3.4%	10767
	Goal:	70.1%	74.5%	70.1%	9.0%	10800
6/89 - 5/90	Actual:	81.8%	84.1%	81.8%	1.0%	10825
	Goal:	81.9%	86.3%	81.9%	7.9%	10800
MILLSTONE 3						
6/86 - 5/87	Actual:	78.7%	83.1%	78.7%	9.8%	10348
	Goal:	65.4%	75.4%	65.4%	24.6%	10365
6/87 - 5/88	Actual:	62.8%	66.0%	62.7%	8.6%	10342
	Goal:	63.2%	67.4%	63.2%	14.9%	10328
6/88 - 5/89	Actual:	79.9%	84.1%	79.8%	11.0%	10421
	Goal:	70.1%	74.7%	70.1%	9.7%	10355
6/89 - 5/90	Actual:	69.2%	75.8%	69.2%	14.3%	10445
	Goal:	68.9%	73.5%	68.9%	9.9%	10355

2.12 MICHIGAN

Michigan Public Service Commission

Consumers Power: Palisades, 100%
Big Rock Point, 100%

Indiana/Michigan Power: Cook 1 and 2, 100%

Program Status: Effective 1983.

Performance Criterion: Capacity Factor.

Type of Incentive Program: Subjective power cost recovery disallowance.

Description: In 1987 the Michigan Public Service Commission (PSC) staff initiated a full public hearing to discuss a proposal for an incentive program that would require a minimum annual capacity factor of 60% for Consumers Power's nuclear units. The motivation for the proposal was the Palisades nuclear unit performance. The proposed 60% capacity factor for the unit was less than the industry average, but greater than the then recent past performance of Palisades. The proposed capacity factor was viewed as a compromise that Palisades should be able to achieve. The proposal was considered to be potentially applicable to all Michigan nuclear units; however, it was rejected in the 1989 Power Supply Cost Recovery (PSCR) extended hearing.

The proposed incentive program was rejected primarily due to the age of the Palisades unit, which made it extremely difficult to arrive at a performance standard that would be appropriate over an extended period of time. Therefore, it was determined that the 1983 Michigan statute establishing the PSCR would continue to provide the basis for determining acceptable performance and prudency for the nuclear units of Consumers Power. In addition, the PSC staff was ordered to conduct more thorough prudency investigations, particularly if a nuclear unit's capacity factor fell below 60%. A power cost recovery disallowance may be imposed on the utility as a result of a prudency investigation.

The PSCR is an annual proceeding consisting of two parts. Projected power costs are first filed for the next 12-month rate period and the rates are implemented; then the last year's projected costs are reconciled with the actual recovered power costs for the period just concluded.

Financial Impact Data: Table 2.16, Power Cost Recovery Disallowances for Consumers Power, lists the power cost recovery disallowances incurred by the utility since the PSCR proceeding was established in 1983. (Financial impact data for Indiana/Michigan Power is currently unavailable.)

TABLE 2.16. Power Cost Recovery Disallowances for Consumers Power

Period	($ Disallowance)
1983	0
1984	(6,543,000)
1985	0
1986	(19,854,000)
1987	(9,827,000)
1988	0

2.13 MICHIGAN

Michigan Public Service Commission

Detroit Edison: Fermi 2, 84.8%

Program Status: Effective January 1991.

Performance Criterion: Capacity Factor.

Type of Incentive Program: Banked Reward and Penalty.

Description: A 1987 incentive program proposal initiated in a Consumers Power proceeding was rejected. This program was potentially applicable to all Michigan nuclear units, including Fermi 2. A settlement negotiated in a subsequent 1988 Detroit Edison rate case, however, imposed an incentive program on Fermi 2. In addition to the incentive program, the settlement also allows for approximately $4 billion of the $5 billion investment in Fermi 2 to be included in rate base. The utility's base rates are frozen and the Power Supply Cost Recovery (PSCR) proceedings are suspended through 1992. The incentive program's nuclear performance standards will be employed to adjust utility revenues when the PSCR proceedings are reinstated.

The nuclear performance standard will require the unit's three-year, rolling capacity factor (commencing in 1991) to meet the greater of two criteria: either a 50% capacity factor or the average capacity factor of the top 50% of the nation's boiling water reactors. Required revenue adjustments are to occur at the conclusion of each 12-month performance period. A disallowance will be imposed on the utility based on the net incremental cost of replacement power for a capacity factor below the minimum standard. Rewards are not directly applied when the performance standard is exceeded; however, rewards that might have accrued for these periods may be used to offset penalties in subsequent years when performance is below the standard. Thus, the rate order provides for a banking mechanism that can be used to offset penalties but does not provide for actual rewards.

Financial Impact Data: For the period in which the PSRC suspension is effective, the utility will be responsible for absorbing any under-recovery of fuel costs and may retain any over-recovery of fuel costs. The incentive program's revenue adjustment, if any, for the initial performance period will not be determined until 1993. Consequently, data on penalties or banked rewards are not available. The incentive program does not specify maximums with respect to either penalties or banked rewards. In addition, there are no provisions for review by the Michigan Public Service Commission once the utility begins to incur penalties.

2.14 NEW JERSEY

New Jersey Board of Public Utilities

Public Service Electric and Gas: Peach Bottom 2 and 3, 42.5%
Salem 1 and 2, 42.5%
Hope Creek, 95%

Jersey Central Power and Light: Oyster Creek, 100%
Three Mile Island, 25%

Program Status: Effective January 1987; revisions effective January 1990 for Public Service Electric and Gas.

Effective March 1987; revisions effective March 1990 for Jersey Central Power and Light.

Performance Criterion: Capacity Factor.

Type of Incentive Program: Reward and Penalty.

Description: The New Jersey Board of Public Utilities (NJBPU) adopted performance standards in lieu of the previous case-by-case investigations that had determined whether or not a particular outage called for a monetary disallowance. The program is intended to shift the risks of poor nuclear performance from the ratepayer to the utility. The performance standard program is applied to each of the three utilities that operate or invest in New Jersey nuclear units: Atlantic City Electric; Jersey Central Power and Light (JCP&L); and Public Service Electric and Gas (PSE&G). Atlantic City Electric is a minor investor in Salem 1 and 2 (7.4%), Peach Bottom 2 and 3 (7.5%), and Hope Creek (5%); therefore, a detailed survey of the program's impact on this utility was not conducted.

Performance standards were established in 1987 and modified in 1989. The performance standard established in 1987 measured the composite capacity factor over a 12-month performance period for each utility. The provisions of the program established a target capacity factor of 70% and a deadband of 60% to 80%. The deadband was established to allow for variations due to refueling outages scheduled during performance periods. An average capacity factor between 80% and 90% for a utility's nuclear units yielded a reward equal to 20% of the fuel cost savings (recovery of 120% of the fuel costs). For performance greater than 90%, the reward was equal to 25% of the fuel cost savings. For capacity factors between 50% and 60%, the utility's recovery of replacement fuel costs was limited to 80%, resulting in a 20% penalty (disallowance). The penalty for capacity factors between 40% and 50% was 25%. Penalties for capacity factors below 40% were to be based on a special review of the circumstances by NJBPU; these reviews included the utility's explanation of causes. All revenue adjustments were calculated from the target capacity factor at the rate corresponding to the capacity factor achieved.

Hearings were begun in October 1989 to review the nuclear performance standards. Provisions for these hearings were made when the original standards were established. The review of the original program specifications and the subsequent revisions were intended to address aspects of the program that were controversial. The impact of performance standards on the management of the nuclear units and on ratepayers and investors was discussed in the course of the hearings. Specific attributes of the standards were also examined and, in a number of instances, revised.

The consensus of the utilities at the 1989 hearings was that the performance standards have not had an appreciable impact on the management of the nuclear units. The utilities indicated that the operation of the units involves consideration of factors more important than the economic rewards or penalties of the standards, such as the NRC's requirements and general safety considerations. The utilities testified that the existence of performance standards have not had any measurable adverse impact on the safe operation of the nuclear units.

The revenue adjustments imposed by the current standards clearly have impacted the ratepayers and utility investors. The disallowance of certain replacement fuel costs has resulted in savings to the ratepayers and measurable costs to the utilities. The utilities expressed concern about the effect the imposition of nuclear performance standards has had on the financial community's perception of utilities. They pointed out that the major rating agencies have downgraded a number of utility securities. The NJBPU indicated that the investment risk of one utility versus another would include, among other factors, the aggregate investment in nuclear units owned or operated by a utility, a phenomenon which should be recognized by the market.

The 1989 revisions to the incentive program limit both the deadband range, where neither a penalty nor a reward accrues, and the percentage of replacement fuel costs the utility may collect from ratepayers. The percentage of fuel cost savings that accrue to the utility was adjusted and the method of calculation of plant capacities and the cost basis against which the penalty and reward percentages are applied were revised.

The revised nuclear performance standards reduced the deadband range to a 65% to 75% "zone of reasonableness" and increased replacement fuel cost penalties (disallowances) for nuclear unit performance below 65%. At capacity factors ranging from 55% to 65%, the utility's recovery of replacement fuel costs is limited to 70%, resulting in a 30% penalty. The penalty for capacity factors between 45% and 55% equals 40% of the replacement fuel costs; between 40% and 45% the penalty equals 50%. The revised standards also allow for rewards when performance reaches 75%; at this point, 30% of the fuel cost savings accrues to the utility. Unit capacity is now calculated according to the unit's maximum dependable capacity (MDC) rating. MDC measures the output that the unit is realistically capable of reaching when operating at full capacity. Previously, unit capacity was calculated on the basis of the unit's design electrical rating (DER), a slightly higher rating than MDC.

The "hard shoulder" of the 1987 performance standards and the policy of calculating penalties from the 70% target capacity factor needed revision. According to the old standard, a utility would be penalized at the rate corresponding to the unit's actual capacity for each percentage point below the 70% target, even if the actual capacity fell into a more expensive range by only 1%. The revised program specifies that revenue adjustments are to be determined from the edges of the zone of reasonableness, eliminating the hard shoulder effect of the deadband. For example, with a capacity factor of 54%, 1% below the 55% to 65% range, the utility would incur a penalty of 30% of the replacement fuel costs for the 10% within the 55% to 65% range and a penalty of 40% for the 1% within the 45% to 55% range.

Table 2.17, New Jersey's Original and Revised Performance Standards and Revenue Adjustments, summarizes the programs in terms of the percentage of fuel costs the utility is permitted to recover from ratepayers. A cost recovery level of 130% is equivalent to a reward of 30% of the fuel cost savings. Similarly a cost recovery level of 70% is equivalent to a penalty or disallowance of 30% of the replacement fuel costs. At capacity factor levels below 40%, the NJBPU intervenes to review the circumstances associated with poor performance; these reviews include the utility's explanation of causes.

TABLE 2.17 New Jersey's Original and Revised Performance Standards and Revenue Adjustments

ORIGINAL PROGRAM		REVISED PROGRAM	
Composite Capacity Factor	Cost Recovery	Composite Capacity Factor	Cost Recovery
90% and above	125%	75% and above	130%
80% - 90%	120%	65% - 75%	0%
60% - 80%	0%	55% - 65%	70%
50% - 60%	80%	45% - 55%	60%
40% - 50%	75%	40% - 45%	50%

The 1990 program revisions were ordered in July and will be applied in the current period of performance. The levelized energy adjustment clause (LEAC) year (the period of performance) for PSE&G is from January 1 through December 31. For JCP&L, the LEAC year is from March 1 through February 28. The program will be subject to review again in 18 months.

Financial Impact Data: The program revisions effective for the current year have not been in place long enough to evaluate the long term effects accurately. PSE&G regards the revised performance standard as marginally more equitable than the original standard. JCP&L reports that the revised performance standard may increase its opportunity to earn a reward. It has also been suggested that the program's impact on the utilities potential losses or gains will be minimal, except in cases of extremely poor performance. Furthermore, large fluctuations in the composite performance of a utility's nuclear units are not anticipated. The impact of a single unit's poor performance would be offset by adequate performance of the utility's other nuclear units. However, JCP&L may be at greater risk than PSE&G for incurring a penalty, as their composite capacity factor is based on the performance of only two nuclear units.

The maximum penalty that can be attributed to the performance standards is 50% of the replacement fuel costs for a composite nuclear capacity factor of 40%. At capacity factors below 40%, the NJBPU would intervene. In these cases, the NJBPU could take actions, such as removing the poorly performing unit(s) from rate base or removing the unit(s) from the performance program and disallowing recovery of a portion of replacement fuel costs. NJBPU intervention is intended as a review of the circumstances that caused a particular unit's poor performance and is not necessarily intended to be extremely punitive.

Financial Impact upon Public Service Gas and Electric: The performance of PSE&G's nuclear units and the associated rewards or penalties as defined by the original standards are shown in Table 2.18, Public Service Electric and Gas' Revenue Adjustments as Determined by Composite Capacity Factor. The 1987 and 1988 data were reported in the July 1990 Decision and Order of the NJBPU. PSE&G's composite DER capacity factor for 1989 includes Peach Bottom Unit 2 for the six months July through December, and excludes Peach Bottom Unit 3 for the entire year. Currently, Salem 1 and 2 are down for unscheduled maintenance; the outage of one of the two units will be extended for scheduled refueling.

Financial Impact upon Jersey Central Power and Light: The performance of JCP&L's nuclear units and the associated rewards or penalties as defined by the original standards are shown in Table 2.19, Jersey Central Power and Light's Revenue Adjustments as Determined by Composite Capacity Factor. Data regarding the LEAC years concluding February 1988 and 1989 were reported in the July 1990 Decision and Order of the NJBPU. For the period ending February 1989, the scheduled refueling outages of both Oyster Creek and Three Mile Island were extended, reducing the capacity factor for the performance period. The projected composite capacity factor (72.5%) for the current LEAC year (March 1990 - February 1991) is based on six months of actual data and six months of forecasted data. Oyster Creek is expected to perform at a 75% capacity factor; Three Mile Island at 80%.

TABLE 2.18. Public Service Electric and Gas' Revenue Adjustments as Determined by Composite Capacity Factor

Period	Composite Capacity Factor	$ Reward ($Penalty)
1987	54.8%	(19.5 million)
1988	49.0%	(22.5 million)
1989	72.0%	0

TABLE 2.19. Jersey Central Power and Light's Revenue Adjustments as Determined by Composite Capacity Factor

Period Month/Year - Month/Year	Composite Capacity Factor	$ Reward ($Penalty)
3/87 - 2/88	69.0%	0
3/88 - 2/89	53.2%	(4.8 million)
3/89 - 2/90	61.7%	0

2.15 NEW MEXICO

Nuclear Performance Incentive

New Mexico Public Service Commission

El Paso Electric: Palo Verde 1 and 2, 15.8%

Program Status: Effective January 1985.

Performance Criterion: Capacity Factor.

Type of Incentive Program: Reward and Penalty.

Description: The New Mexico Public Service Commission's (PSC) jurisdiction over El Paso Electric is due to the utility's New Mexico service area. The revenue adjustments determined by the nuclear performance standards are applied to two-thirds of El Paso Electric's output entitlement in the Palo Verde units. (Palo Verde 3 is excluded from rate base.)

The measure of performance is the annual composite capacity factor for Palo Verde 1, 2, and 3. The performance periods are calendar years; corresponding revenue adjustments are made each year. The established deadband ranges from 60% to 75%. For a capacity factor between 75% and 85%, the utility incurs a reward equal to 50% of the fuel cost savings; above 85%, the utility's reward equals 100% of the fuel cost savings. For a capacity factor between 50% and 60%, the utility incurs a penalty equal to 50% of the replacement fuel costs; below 50%, the utility's penalty equals 100% of the replacement fuel costs. The determination of fuel cost savings or replacement fuel costs is based on a proxy-weighted, average fuel cost.

At an annual capacity factor below 35%, a prudency investigation may be initiated. However, for El Paso Electric, an annual capacity factor below 35% results in an automatic reconsideration of the utility's last general rate in order to determine whether or not continued rate base treatment of the units is appropriate. Unless the PSC orders otherwise, the imposition of performance penalties continues pending the outcome of such reconsideration.

Financial Impact upon El Paso Electric: The reported annual capacity factor and the corresponding revenue adjustments since the program became effective are shown in Table 2.20, El Paso Electric's Revenue Adjustments as Determined by Composite Capacity Factor. Due to the poor 1989 performance, the result of extended outages in each of the Palo Verde units, a review of the last general rate will be conducted. In addition, the utility is preparing for a rate case involving operating and maintenance expenses, and expenses associated with the outage. El Paso Electric estimates the Palo Verde capacity factor for 1990 to be 56%, which would result in a $77,000 penalty.

TABLE 2.20. El Paso Electric's Revenue Adjustments as Determined by Composite Capacity Factor

Period	Composite Capacity Factor	$ Reward ($Penalty)
1987	60.5%	0
1988	70.4%	0
1989	23.4%	(1.48 million)

2.16 NEW MEXICO

New Mexico Public Service Commission

Public Service Company of New Mexico: Palo Verde 1 and 2, 10.2%

Program Status: Effective May 1990.

Performance Criterion: Capacity Factor.

Type of Incentive Program: Reward and Penalty.

Description: Performance standards were established for Public Service Company of New Mexico's (PSCoNM) investment in Palo Verde 1 and 2 in the course of the construction prudency review. The stipulation made during the review resolved all issues regarding prudence of Palo Verde's construction including: the common facilities, system planning, and construction costs. The revenue adjustments determined by the nuclear performance standards are applied to two-thirds of PSCoNM's output entitlement from the Palo Verde units. (Palo Verde 3 is excluded from rate base.)

Nominally, the average capacity factor for the Palo Verde units will be measured as a function of the 18-month fuel cycle, while the fuel cost savings or replacement fuels costs attributable to the utility will be determined on an annual basis. However, the performance standard will be applied for the first time, based on the 12-month period of performance beginning May 1990. The performance standards and corresponding revenue adjustments adopted are similar to those applied to El Paso Electric. The established deadband ranges from 60% to 75%. For a capacity factor between 75% and 85%, the utility incurs a reward equal to 50% of the fuel cost savings; above 85%, the utility's reward equals 100% of the fuel cost savings For a capacity factor between 50% and 60%, the utility incurs a penalty equal to 50% of the replacement fuel costs; below 50%, the utility's penalty equals 100% of the replacement fuel costs. The fuel savings or costs are calculated as the difference between the average system fuel cost and the fuel cost for Palo Verde.

The stipulation made during the prudency review, agreed on by the New Mexico Public Service Commission (PSC) staff and PSCoNM, has been approved by the PSC. However, the State Attorney General has appealed the stipulation to the Supreme Court, contending that the construction prudency review failed to address the full merits, and that the PSC staff lacks the authority to enter into a stipulation.

Financial Impact Data: In the stipulation that resolved all issues regarding the prudence of Palo Verde, PSCoNM agreed to a $90 million disallowance from the New Mexico rate base. Revenue impact data of the performance standard will not be available until the initial period of performance concludes in May 1991.

2.17 NEW YORK

New York Public Service Commission

Rochester Gas and Electric: Ginna, 100%
Nine Mile Point 2, 14%

Niagara Mohawk Power: Nine Mile Point 1, 100%
Nine Mile Point 2, 41%

New York State Electric and Gas: Nine Mile Point 2, 18%

Program Status: Effective 1985.

Performance Criterion: Fuel Costs.

Type of Incentive Program: Reward and Penalty.

Description: A fuel adjustment clause applies to all New York utilities. However, partial pass-through mechanism applies to Rochester Gas and Electric, Niagara Mohawk Power, and New York State Electric and Gas; as a result, the utilities are not necessarily allowed to pass through 100% of the actual fuel costs. Long Island Lighting is exempt from partial pass through due to financial difficulties. Consolidated Edison has been exempt because of a rate case settlement in 1981. A negotiated settlement in the 1989 rate case allowed Consolidated Edison to continue to pass through 100% of their fuel costs.

Each month, the fuel adjustment clause compares target unit fuel costs and the actual recoverable fuel cost per unit of sendout for the utility's retail customers. The partial pass-through mechanism uses a sliding scale percentage to reconcile fuel cost departures from the monthly target. An 80/20% share of costs between ratepayers and the utility applies to departures up to a specified absolute dollar limit for each utility; departures in excess of the specified dollar limit are shared 90/10% up to a specified cap. The utility recovers from ratepayers 100% of departures in excess of the specified cap. The absolute dollar limit and the cap are based on the size and financial health of the utility.

In practice, for a utility that exceeds the targeted costs, an 80/20% share of departures from the target results in passing 80% of the excess cost to the ratepayers and the utility absorbing the remaining 20% of the actual costs. Conversely, if the utility's actual costs are below the target, 80% of the savings are passed on to the ratepayers, and the utility is allowed to retain 20% of the savings as a positive incentive. Therefore, if the utility's fuel costs fall below the target, the utility recovers revenues in excess of actual fuel costs for the month.

Due to fluctuating fuel prices, the Commission is currently considering determining efficiency with indexed fuel costs based on the price fluctuations rather than predetermined monthly targets. This change, however, is only in the planning stage. Similarly, a nuclear safety performance incentive program that was proposed in 1986, and subsequently withdrawn, remains under consideration and is subject to refinement.

The 1986 safety performance incentive proposal included the NRC's Systemic Assessment of Licensee Performance (SALP) ratings and trends. NRC civil penalties for violating safety regulations were also to be used to determine if a utility should be denied rewards. Penalties were to be implemented through the utility's fuel adjustment clause, while rewards were to be tied to the allowed rate of return on common equity. In addition, cash bonuses were to be given directly to employees of a nuclear unit that qualified for a safety performance reward. For a utility with more than one nuclear unit, each unit was to be subject to rewards or penalties based on unit performance.

Financial Impact Data: Table 2.21, Partial Pass Through Sliding Scale, shows utilities affected by the partial pass-through mechanisms and the specified absolute dollar limits and caps for each utility.

TABLE 2.21. Partial Pass-Through Sliding Scale

Utility	80/20 Limitation	90/10 Limitation	Cap
Niagara Mohawk Power	First $50 million	Second $50 million	$100 million
Rochester Gas and Electric	First $26 million	N/A	$ 26 million
NY State Electric and Gas	First $40 million	Second $40 million	$ 80 million

2.18 NORTH CAROLINA

Utility Performance Standard
Utility Economic Incentive

North Carolina Utilities Commission

Carolina Power and Light: Brunswick 1 and 2, 81.5%
Robinson, 100%

Duke Power: McGuire 1 and 2, 100%
Oconee 1, 2, and 3, 100%
Catawba 1, 25%

Virginia Electric and Power: Surry 1 and 2, 100%
North Anna 1 and 2, 88.4%

Program Status: Effective 1987.

Performance Criterion: Capacity Factor.

Type of Incentive Program: Subjective denial of under-collected fuel costs. Subjective determination of rate of return on equity.

Description: In a 1987 rule-making proceeding, the North Carolina Utilities Commission's (NCUC) public staff submitted a proposal that would have required a utility to absorb 90% of fuel cost overruns. In the event of an underrun, the utility would be permitted to retain 10% of the fuel cost savings. The NCUC rejected the proposal. Instead, the rule-making proceeding enabled the NCUC to retrospectively adjust for under-collection and over-collection. The rule provisions were set forth for an initial two-year period and in 1989 were extended for an additional two years.

NCUC estimates fuel costs for each 12-month performance period. A utility is permitted to include a fuel charge adjustment as a rider to the rates. The amount of a fuel charge can be reset only once during the 12-month period. It can also be reset at general rate hearings. The NCUC holds a full evidentiary hearing to determine whether an increment or decrement rider is in order. The only allowed portions of a requested fuel charge are those based on reasonable adjustments for fuel expenses that have been prudently incurred under efficient management and operations. Moreover, state statutes limit fuel cost recovery to actual costs; thus, in the event the utility over-collects fuel costs, the utility must reimburse ratepayers the over-collected fuel costs with interest.

The NCUC uses the target capacity factor, in part, to reconcile under-recovery allowances. The target capacity factor is based on an industry-wide average and considers a particular unit's characteristics and performance history. A target capacity is then determined for the forthcoming 12-month period. A unit that achieves the target capacity factor is not expected to under-recover costs. For a unit which under-collects costs and meets the target capacity factor, the NCUC must establish utility imprudency to deny recovery of costs. However, should the unit fail to achieve the target capacity factor, the utility must establish prudency in order to recover costs that were under-collected. Interest on under-collected costs is not permitted.

With respect to the adjustment of a utility's allowed rate of return, the NCUC may consider a utility's performance and management as a factor in determining the rate of return. A recent North Carolina Supreme Court opinion has cast doubt on whether the NCUC can increase a utility's allowed rate of return as a reward for good performance.

Financial Impact Data: Since the 1987 rule-making proceeding, which allows for retrospective adjustments for under- and over-recovery of fuel costs, Duke Power and Virginia Electric and Power have not been subject to a disallowance of under-collected fuel costs due to imprudency. However, Virginia Electric and Power's nuclear capacity for the July 1988 - June 1989 period of performance was 47%. In a negotiated settlement, the utility agreed not to seek recovery of $1.5 million in replacement fuel costs. Carolina Power and Light, for the February 1990 - August 1990 period, was denied $422,000 in under-collected fuel costs.

2.19 OHIO

Utility Performance Standard
Nuclear Performance Incentive

Public Utilities Commission of Ohio

Toledo Edison: Davis-Besse, 48.6%
Perry 1, 19.9%
Beaver Valley 2, 19.9%

Cleveland Electric Illuminating: Davis-Besse, 51.4%
Perry 1, 31.1%
Beaver Valley 2, 24.5%

Ohio Edison: Perry 1, 30%
Beaver Valley 1, 35%
Beaver Valley 2, 41.9%

Program Status: Effective January 1988.

Performance Criterion: Operating Availability Factor.

Type of Incentive Program: Subjective denial of under-collected system loss adjustment.
Banked Reward and Penalty.

Description: The Public Utilities Commission of Ohio conducts a hearing every six months to determine allowable fuel cost recovery for the ensuing six months. Ohio allows for recovery of under-collected system loss adjustment (SLA) based on a complex composite measure of system performance and utility efficiency, which indicates whether a utility's generating assets have been operated in a prudent manner. Over-collections due to SLA are entirely refunded. Requiring efficiency provides the utility with an incentive to minimize its costs. The procedure for the collection of SLA applies to each Ohio utility and is determined as a function of all generating assets. In addition, the 1988 rate cases involving Toledo Edison and Cleveland Electric Illuminating and the 1989 rate case for Ohio Edison resulted in the adoption of a performance standard based on the operating availability of each nuclear unit.

The nuclear performance standard will first be applied in the 1991 fuel component proceedings for each utility. The operating availability factor is a comparison of each unit's three-year, rolling average and the three-year, rolling, industry average for pressurized water reactors or boiling water reactors (excluding any unit operating at less than 30% availability for the period). The target operating availability and unit performance will be determined for the first time in 1991, using the three-year averages of 1988 through 1990. In the event that performance of a utility's nuclear unit is below the industry average, a fuel disallowance is computed by multiplying the net incremental cost of replacement power by the kilowatts required to raise the availability factor to the industry average. A penalty is applied through the reconciliation adjustment of the electric fuel component rate. Ohio only permits recovery of the actual costs of fuel used in electrical generation; thus, a provision for rewards is not included in the program. However, a mechanism was established such that if a utility's nuclear performance is above the industry average, rewards that might have accrued are "banked."

Banked rewards can only be used to offset penalties incurred in the recent past or those that may be incurred in the future.

An operating availability factor was selected rather than a capacity factor because of a unique characteristic of these utility systems. Currently, the capacity represented by the nuclear units serving the area exceeds the off-peak demands of the utilities. As a result, all the nuclear units cannot be fully loaded during off-peak periods. Under these circumstances, using the capacity factor, which measures actual unit utilization relative to the unit's potential capacity, would not be appropriate. A number of the parties involved in formulating the incentive program preferred using the equivalent availability factor, but currently this measure is not readily available industry-wide. Others object to the use of equivalent availability on the basis that it is a more subjective measure than operating availability. Equivalent availability, unlike operating availability, considers losses due to partial as well as full outages. While equivalent availability better captures unplanned losses, the extent to which a unit was operating at lower capacity due to problems or as a result of other factors (i.e., capacity exceeding off-peak demand) may be a subjective determination. A stipulation was included in the order stating that, if data on industry-wide equivalent availability becomes readily available, the performance standard will be re-evaluated.

Financial Impact Data: Available data indicate that for the last five years, Ohio utilities have not been subject to denial of under-collected system loss adjustment. However, Ohio Edison was denied recovery of $19,800 in under-collected system loss adjustment for the January - June 1985 period.

The impact of the nuclear performance incentive program is difficult to estimate since the database required to calculate departures from the industry average and the replacement fuel costs associated with these departures has not yet been constructed. However, based on the past performance of their nuclear units, the utilities are not expected to incur penalties. Each of the nuclear units has performed at or above the performance standard over the past three years.

The program does not specify maximums with respect to either penalties or banked rewards. However, should performance for a unit fall below 35% for a three-year period, the Commission will initiate an investigation into the causes of the unit's poor performance. In addition, the Commission will determine whether the utility should continue to earn a return on its investment in the unit and whether the utility should continue to recover depreciation on the unit from its ratepayers.

2.20 PENNSYLVANIA

Construction Cost Cap
Nuclear Performance Incentive

Pennsylvania Public Utility Commission

Philadelphia Electric: Limerick 1 and 2, 100%
Salem 1 and 2, 42.6%
Peach Bottom 2 and 3, 42.5%

Program Status: Effective April 1990.

Performance Criterion: Capacity Factor.

Type of Incentive Program: Reward and Penalty.

Description: The Pennsylvania Public Utility Commission issued an order in December 1985 that stated Philadelphia Electric could complete the construction of Limerick 2 in accordance with the construction cost plan and the nuclear performance incentive program set forth in the order. The cost containment plan specified that the maximum net rate base allowance was not to exceed a prudent investment of $3.197 billion. The construction cost cap was addressed in the April 1990 rate case. Of the $2.82 billion in construction costs, approximately $210 million was disallowed. The disallowances, approximately $50 million for the Limerick 2 unit and $160 million for the common plant, were primarily associated with schedule issues.

The nuclear performance incentive program for Limerick 2, which began commercial operation in January 1990, was revised in the rate case that added the unit to base rates. The revision to the Energy Cost Adjustment (ECA), effective April 1990, incorporates a nuclear performance standard and replaces the existing Energy Cost Rate Factor for all of Philadelphia Electric's nuclear units. The objectives of the nuclear performance standard and corresponding revenue adjustments are to equitably balance the interests of the utility and its ratepayers, and to produce just and reasonable rates.

The ECA measures Philadelphia Electric's composite nuclear capacity factor for the calendar year. A component of the ECA, referred to as the performance adjustment, defines rewards and penalties as a function of the nuclear composite capacity factor. In addition to any over-collection of actual energy costs, the performance adjustment requires Philadelphia Electric to refund a portion of the replacement power costs incurred during the one-year performance period due to nuclear performance at less than a designated range of acceptable capacity. The performance adjustment also permits the utility to retain a portion of the replacement power costs avoided due to nuclear performance above the designated range of acceptable capacity. The performance adjustment is defined in Table 2.22, Philadelphia Electric's Performance and Revenue Adjustments.

The revisions to the ECA also specify that if a nuclear unit is out of service for more than 120 consecutive days, or does not achieve a capacity factor of 50% or more during a performance year, the PUC will retain the authority to conduct an investigation of that unit's performance. The PUC may disallow recovery of up to 100% of replacement power costs found to have been imprudently incurred. Disallowances of 100% of replacement power costs

TABLE 2.22. Philadelphia Electric's Performance Standards and Revenue Adjustments

Composite Capacity Factor	Revenue Adjustment
above 85%	40% replacement power savings
above 75% but not above 85%	30% replacement power savings
above 70% but not above 75%	20% replacement power savings
between 60% and 70%	0
below 60% but not below 55%	20% replacement power costs
below 55% but not below 45%	30% replacement power costs
below 45%	40% replacement power costs

imprudently incurred are consistent with the PUC decisions in the past. A unit that has failed to perform would not be subject to the performance adjustment and would be excluded from the composite capacity factor calculation. However, the normal operation of the ECA will replace routine annual reviews of nuclear performance, and disallowance of replacement fuel costs will not occur if the unit meets the required capacity factor. The ECA will not be subject to modification for a minimum of three years in order to provide a fair test of its ability to achieve the desired objectives.

Financial Impact Data: Projections made by Philadelphia Electric with respect to potential rewards or penalties based on the ECA specifications are subject to various factors that cannot be determined with great accuracy. While the program has not established maximum rewards or penalties, the provision excluding a unit that fails to meet the minimum capacity factor and subjects that unit to a prudency review effectively insulates the utility from severe financial loss. The utility views the program's impact on plant operational budgets as minimal since the program is intended to function as an alternative to routine individual outage reviews. Philadelphia Electric indicates that the utility was adequately involved in the negotiation process that determined the nuclear performance standards; these standards are consistent with the unit's performance to date. According to the utility, the advantages of the ECA are that it has eliminated changes to the fuel clause, reduced unknown consequences of poor unit performance, and established an equitable performance standard. Also, the program replaces the adverse atmosphere frequently found in prudency reviews, and establishes a constructive fuel cost recovery mechanism that provides consumers with protection from excessive fuel costs due to poor performance.

2.21 TEXAS Proposed Incentive Program

Texas Public Utility Commission

El Paso Electric: Palo Verde 1, 2, and 3, 15.8%

Program Status: Proposed 1987, subject to decision 1990.

Performance Criterion: Capacity Factor.

Type of Incentive Program: Reward and Penalty.

Description: The nuclear performance incentive program proposals currently in review by the Texas Public Utility Commission examiner were initiated in the course of the 1987 El Paso Electric rate case. The PUC staff cites a number of reasons for incentive regulation: the high capital costs of new base-load capacity; a perceived need to encourage greater efficiency in utility operations; and a desire to establish a means of more equitably allocating risks and rewards between shareholders and ratepayers.

The PUC staff program proposed to employ capacity factor as the primary performance indicator for each unit. A composite capacity factor of the three units would be used as the basis to determine performance-based rewards or penalties. Penalties or rewards would be determined on an annual basis. The target capacity factor would be based on the average monthly capacity factor of units with a capacity greater than 50%. The deadband range would be equal to the target ±7.5%. Rewards or penalties for performance outside of the deadband would be equal to 50% of the difference between the cost of power produced by the Palo Verde units and the cost of the replacement power, as calculated in the fuel reconciliation. If the capacity factor for any one unit fell below 50% for the three-year evaluation period, the entire operating period of three years would be subject to a detailed evaluation. The proposed program is not perceived by the PUC staff to affect Palo Verde's operational safety.

The El Paso Electric proposal also specifies capacity factor as the measure of performance. However, the first performance evaluation period for each unit is to begin on the effective date of the new rates and continue to the start of the refueling outage. Similarly, in subsequent years, the annual capacity factor will be determined for each unit using the refueling cycle period performance. The annual capacity factor is to be calculated by dividing the capacity factor for the cycle by the number of months in the cycle and multiplying by 12. Features of the program proposed by the utility is shown in Table 2.23, Performance Standards and Revenue Adjustments Proposed by El Paso Electric.

TABLE 2.23. Performance Standards and Revenue Adjustments Proposed by El Paso Electric

Capacity Factor	Revenue Adjustment
above 85%	100% fuel costs avoided
75% - 85%	50% fuel costs avoided
60% - 75%	0
50% - 60%	50% fuel costs incurred
below 50%	100% fuel costs incurred

The proposals submitted by the PUC staff and El Paso Electric, among others, are under consideration. The examiner's report and order will provide recommendations to the PUC, who in turn will make a decision regarding the application of a nuclear incentive program to El Paso Electric. In the event nuclear performance standards and corresponding revenue adjustments are adopted, such a program is potentially applicable to all of the Texas utilities with investments in nuclear units: Houston Lighting and Power, Texas Utilities Electric, and Gulf States Utilities.

Financial Impact Data: The potential financial impact of a nuclear incentive program has not been evaluated, as the requirements have yet to be determined.

2.22 VIRGINIA

Utility Performance Standard
Utility Economic Incentive

Virginia State Corporation Commission

Virginia Electric and Power: Surry 1 and 2, 100%
North Anna 1 and 2, 88.4%

Program Status: Effective January 1979.

Performance Criterion: Capacity Factor (primary measure).

Type of Incentive Program: Subjective denial of replacement fuel costs. Subjective determination of rate of return on equity.

Description: The Virginia State Corporation Commission (VSCC) conducts two annual utility proceedings: a fuel proceeding, to determine the reasonableness of fuel expenses; and a rate proceeding, to determine the allowed rate of return on equity.

The fuel recovery clause defines a procedure for evaluating the reasonableness of fuel expenses. The procedure is based on factors such as generating unit performance, delivered fuel prices, system load, and interchange levels. Of these factors, generating unit performance is one area over which utilities can exercise a significant degree of control. For nuclear units, evaluations of performance are based on five indices: capacity factor, availability factor, equivalent availability factor, heat rate, and forced outage rate. The utility provides projected fuel expenses for a 12-month period for the system. Projected expenses assume a performance level for each unit on the system. Over the 12-month period, monthly fuel costs for each unit on the system are submitted to the VSCC and compared to projections. Investigations are conducted when significant discrepancies occur between the projections and the actual costs, or when performance is below expected levels. A utility may be subject to a prudency review and disallowance of fuel costs because of poor performance.

The VSCC, in determining the rate of return on equity, provides for a positive incentive to the utility. The selected rate of return is a function of the performance of the utility's system as a whole, nuclear units being only one component of the utility's system. The recommended rate of return is based on performance over the entire period of commercial operation as well as the current year.

Financial Impact Data: As determined in the fuel proceeding, a utility does not accrue a reward nor incurs a penalty based on exceeding or failing to meet performance targets. Recovery of fuel costs is based on the reasonableness of a utility's fuel expenses, which is determined, in part, by achieving target levels of performance. Utility performance, however, does influence the selected rate of return on equity. The range established in 1985 for the rate of return on equity was 14% to 15%; Virginal Electric and Power's return for this year was 14.5%. The 198[illegible] range was reduced to 12.5% to 13.5%; the return for this year was [illegible]5%, in recognition of sustained improvement. The current rate of return on equity will be subject to adjustment in the next scheduled hearing due to a 1988 nuclear capacity factor of 48%.

3.0. SUMMARY

Changes within an individual incentive program report (not necessarily to an incentive program) since the 1989 publication of NUREG/CR-5509 are summarized in Table 3.1, "Incentive Programs Grouped by State Regulatory Authority." The number of states that apply incentive programs and the number of affected units have not changed dramatically. As indicated by Table 3.1, incentive programs established by state regulators are applicable to 60 nuclear units in 16 states. The number of nuclear units currently affected by incentive programs excludes those whose report status is listed as discontinued,as well as the Illinois units no longer effected by a utility economic incentive program, and the program proposed by Texas.

Table 3.1 is organized alphabetically by state and includes states that have proposed, current, or recently discontinued incentive programs. The nuclear units within a given state are grouped together by state regulatory program, irrespective of utility ownership. For each nuclear unit subject to a state incentive program, the table lists incentive program classification, report status, and the page number of the individual program report. Incentive programs may be classified as a nuclear performance incentive program, a utility performance incentive program, or a utility economic incentive program. The incentive program classification also indicates those programs that specifically address one aspect of a nuclear unit, such as construction costs or safety. Report status indicates whether or not a program as reported in NUREG/CR-5509 remains the same, has been substantially modified, or has been discontinued. Programs previously not reported are indicated to be new. Discontinued programs are cited as required in individual program reports and appear in Table 3.4, "Summary of State Incentive Programs Discontinued as of 1989"; however, discontinued programs are not included as individual program reports.

Incentive programs currently in effect, as well as programs that have been recently proposed or concluded are briefly described in Table 3.2, "Summary of Incentive Programs by NRC Region." The table consists of five sections corresponding to each NRC region. Incentive programs within each NRC region are organized by state regulatory authority and incentive program classification. The table lists the utilities, nuclear units that are affected by the program, the effective date of a program's implementation, performance criterion, recent penalties and rewards, comments, and the type of program. The type of program refers to how revenue adjustments are made, and the comments bear on the financial impact of the program.

As shown in Table 3.2, 27 utilities are effected by 21 incentive programs. The total number of incentive programs is composed of 11 nuclear performance incentive programs, 7 utility performance standard programs, and 3 utility economic incentive programs. These incentive programs address the operation of nuclear units. Nine of the nuclear performance incentive programs apply both rewards and penalties; the remaining two programs use a banked reward mechanism and penalties. Each of the utility performance standard programs apply economic sanctions. An adjustment to the rate of return on equity applies to two utility economic incentive programs. In addition, the table includes 5 other programs: (1) the construction cost cap imposed on Limerick 2 by the Pennsylvania PUC; (2) the rescinded Illinois economic incentive program for Commonwealth Edison; (3) the nuclear performance incentive proposals before the Texas PUC regarding El Paso Electric; (4) the Performance Based Revenues program applied to Pacific Gas and Electric's Diablo Canyon; (5) and the construction cost cap imposed on Arizona Public Service's investment in the Palo Verde units. Table 3.3, Classification of Incentive Programs, organizes the incentive programs according to the three primary classes and identifies the remaining five programs.

Table 3.4, "Summary of State Incentive Programs Discontinued as of 1989," provides a brief description for incentive programs that ceased to apply prior to 1987. The table's organization is similar to Table 3.2; it identifies the state regulatory authority and incentive program classification, utility, nuclear unit, and effective date of each program. Programs are also described in terms of performance criterion and type of program, including comments. The programs listed in Table 3.4 do not appear as individual program reports, however, they may be referred to in the description of existing incentive programs. For detailed information, refer to NUREG/CR-5509 (1989) for programs discontinued since 1987 or NUREG-1256 Vol. 1 (1987) for programs discontinued prior to 1987.

TABLE 3.1. Incentive Programs Grouped by State Regulatory Authority and Unit

State Regulatory Authority	Nuclear Unit	Incentive Classification	Report Status	Page
Arizona	Palo Verde 1, 2, & 3	Construction Cost Cap	Same	2-2
	Palo Verde 1	Nuclear Performance	Discontinued	N/A
Arkansas	Arkansas Nuclear 1 & 2	Nuclear Performance	Same	2-3
California	Diablo Canyon 1 & 2	Performance Based Revenues	Revised	2-5
	San Onofre 1, 2 & 3 and Palo Verde 1, 2 & 3	Nuclear Performance	Same	2-8
Connecticut	Millstone 1, 2 & 3 and Connecticut Yankee	Performance Standard	Same	2-12
Florida	Crystal River 3, St. Lucie 1 & 2; and Turkey Point 3 & 4	Nuclear Performance	Same	2-14
Georgia	Hatch 1 & 2 and Vogtle 1 & 2	Nuclear Performance	Same	2-19
Illinois	Dresden 2 & 3; La Salle County 1 & 2; Zion 1 & 2; Bryon 1 & 2; Braidwood 1 & 2; Quad Cities 1 & 2; and Carroll County	Rescinded Program	Revised	2-21
Maryland	Calvert Cliffs 1 & 2	Performance Standard	Revised	2-22
Massachusetts	Pilgrim	Nuclear Performance	Revised	2-24
	Pilgrim and Millstone 1, 2 & 3	Performance Standard	Same	2-27

TABLE 3.1. (continued)

State Regulatory Authority	Nuclear Unit	Incentive Classification	Report Status	Page
Michigan	Palisades; Big Rock Point; and Cook 1 & 2	Performance Standard	Revised	2-30
	Fermi 2	Nuclear Performance	Same	2-32
Mississippi	Grand Gulf 1	Performance Standard	Discontinued	N/A
New Jersey	Salem 1 & 2; Hope Creek; Peach Bottom 2 & 3; Oyster Creek; and Three Mile Island	Nuclear Performance	Revised	2-33
New Mexico	Palo Verde 1 & 2	Nuclear Performance	Same	2 38
	Palo Verde 1	Economic Incentive	Discontinued	N/A
	Palo Verde 1 & 2	Nuclear Performance	Revised	2-40
New York	Nine Mile Point 2	Construction Cost Cap	Discontinued	N/A
	Ginna; Nine Mile Point 1 & 2; and Indian Point 2	Safety Incentive	Discontinued	N/A
	Ginna and Nine Mile Point 1 & 2	Economic Incentive	Revised	2-41
North Carolina	Brunswick 1 & 2; Robinson; McGuire 1 & 2; Oconee 1, 2 & 3; Catawba 1; Surry 1 & 2; North Anna 1 & 2	Performance Standard	Same	2-43
	Brunswick 1 & 2; Robinson; McGuire 1 & 2; Oconee 1, 2 & 3; Catawba 1; Surry 1 & 2; North Anna 1 & 2	Economic Incentive	Same	2-43

TABLE 3.1. (continued)

State Regulatory Authority	Nuclear Unit	Incentive Classification	Report Status	Page
Ohio	Davis-Besse; Perry 1; and Beaver Valley 1 & 2	Performance Standard	Revised	2-45
	Davis-Besse; Perry 1; and Beaver Valley 1 & 2	Nuclear Performance	New	2-45
Oregon	Trojan	Economic Incentive	Discontinued	N/A
Pennsylvania	Limerick 2	Construction Cost Cap	Revised	2-47
	Limerick 1 & 2; Salem 1 & 2; and Peach Bottom 2 & 3	Nuclear Performance	Revised	2-47
Texas	Palo Verde 1, 2 & 3	Proposed Program	Revised	2-50
Virginia	Surry 1 & 2 and North Anna 1 & 2	Performance Standard	Same	2-52
	Surry 1 & 2 and North Anna 1 & 2	Economic Incentive	Same	2-52

TABLE 3.2. Summary of Incentive Programs
by NRC Region

REGION I

Regulatory Authority: Program Classification	Utility	Nuclear Unit	Effective Date	Performance Criterion	Recent Reward/ Penalties	Comments/ Type of Program	Page
CONNECTICUT: Performance Standard	CT Light & Power	Millstone 1, 2 & 3 and CT Yankee	July 1979	Annual Capacity Factor	None to Date	Subjective denial of replacement fuel costs	2-12
MARYLAND: Performance Standard	Baltimore Gas & Electric	Calvert Cliffs 1 & 2	January 1988	Annual Capacity Factor	None to Date	Subjective denial of replacement fuel costs	2-22
MASSACHUSETTS: Nuclear Performance	Boston Edison	Pilgrim	November 1989	Annual Capacity Factor; Performance Indicators; and SALP Ratings	'90 Reward $200K	Reward and Penalty	2-24
MASSACHUSETTS: Performance Standard	Boston Edison	Pilgrim	1981; Revised 1985	Annual Equivalent Availability Factor	'86 Penalty $3.0M	Subjective denial of replacement fuel costs	2-27
	Western MA Electric	Millstone 1, 2 & 3	1981; Revised 1985	Annual Equivalent Availability Factor	None to Date	Subjective denial of replacement fuel costs	2-27
PENNSYLVANIA: Construction Cost Cap	Philadelphia Electric	Limerick 2	Concluded 1990	Total Cost	$2.8B Total Cost; $210 M Disallowance	$3.2B maximum net rate base allowance	2-47
PENNSYLVANIA: Nuclear Performance	Philadelphia Electric	Limerick 1 & 2; Salem 1 & 2; and Peach Bottom 2 & 3	April 1990	Annual Capacity Factor	None to Date	Reward and Penalty	2-47

TABLE 3.2. (continued)

REGION I (continued)

Regulatory Authority: Program Classification	Utility	Nuclear Unit	Effective Date	Performance Criterion	Recent Reward/ Penalties	Comments/ Type of Program	Page
NEW YORK: Economic Incentive	Rochester Gas & Electric	Ginna and Nine Mile 2	1985	Fuel Costs	Not Available	Reward and Penalty	2-41
	Niagara Mohawk	Nine Mile 1 & 2	1985	Fuel Costs	Not Available	Reward and Penalty	2-41
	NY State Electric & Gas	Nine Mile 2	1985	Fuel Costs	Not Available	Reward and Penalty	2-41
NEW JERSEY: Nuclear Performance	Public Service Electric & Gas	Salem 1 & 2; Hope Creek; and Peach Bottom 2 & 3	January 1987; Revised 1990	Annual Capacity Factor	'87 Penalty \$19.5M; '88 Penalty \$22.5M	Reward and Penalty	2-33
	Jersey Central Power & Light	Oyster Creek and Three Mile Island	March 1987; Revised 1990	Annual Capacity Factor	'88 Penalty \$4.8M	Reward and Penalty	2-33

TABLE 3.2. (continued)

REGION II

Regulatory Authority: Program Classification	Utility	Nuclear Unit	Effective Date	Performance Criterion	Recent Reward/ Penalties	Comments/ Type of Program	Page
FLORIDA: Nuclear Performance	FL Power	Crystal River 3	September 1980	Semi-Annual Equivalent Availability & Heat Rate	Winter 89/90 Reward $710K	Reward and Penalty	2-14
	FL Power & Light	St. Lucie 1 & 2 and Turkey Pt. 3 & 4	September 1980	Semi-Annual Equivalent Availability & Heat Rate	Winter 89/89 Reward $1.6M	Reward and Penalty	2-14
NORTH CAROLINA: Performance Standard	Carolina Power & Light	Brunswick 1 & 2 and Robinson	1987	Annual Capacity Factor	2/90-8/90 Denied $422K	Subjective denial of under-collected fuel costs	2-43
	Duke Power	McGuire 1 & 2; Oconee 1, 2, & 3; and Catawba 1	1987	Annual Capacity Factor	None to Date	Subjective denial of under-collected fuel costs	2-43
	VA Electric & Power	Surry 1 & 2 and North Anna 1 & 2	1987	Annual Capacity Factor	None to Date	Subjective denial of under-collected fuel costs	2-43
NORTH CAROLINA: Economic Incentive	Carolina Power & Light	Brunswick 1 & 2 and Robinson	1987	Utility Performance	Not Available	Subjective determination of rate of return on equity	
	Duke Power	McGuire 1 & 2; Oconee 1, 2, & 3; and Catawba 1	1987	Utility Performance	Not Available	Subjective determination of rate of return on equity	
	VA Electric & Power	Surry 1 & 2 and North Anna 1 & 2	1987	Utility Performance	Not Available	Subjective determination of rate of return on equity	

TABLE 3.2. (continued)

REGION II (continued)

Regulatory Authority: Program Classification	Utility	Nuclear Unit	Effective Date	Performance Criterion	Recent Reward/ Penalties	Comments/ Type of Program	Page
VIRGINIA: Performance Standard	VA Electric & Power	Surry 1 & 2 and North Anna 1 & 2	January 1979	Annual Capacity Factor	None to Date	Subjective denial of re-placement fuel costs	2-52
VIRGINIA: Economic Incentive	VA Electric & Power	Surry 1 & 2 and North Anna 1 & 2	January 1979	Utility Performance	'86 ROE: 13.25%	Subjective determination of rate of return on equity; 86 ROE Range 12.5%-13.25%	2-52
GEORGIA: Nuclear Performance	GA Power	Hatch 1 & 2 and Vogtle 1 & 2	January 1989	Three Year Capacity Factor	None to Date	Reward and Penalty	2-19

TABLE 3.2. (continued)

REGION III

Regulatory Authority: Program Classification	Utility	Nuclear Unit	Effective Date	Performance Criterion	Recent Reward/ Penalties	Comments/ Type of Program	Page
MICHIGAN: Performance Standard	Consumers Power	Palisades and Big Rock Point	1983	Annual Capacity Factor	'87 Disallow-ance $9.8M	Subjective power cost recovery disallowance	2-30
	Indiana/Michigan Power	Cook 1 & 2	1983	Annual Capacity Factor	Not Available	Subjective power cost recovery disallowance	2-32
MICHIGAN: Nuclear Performance	Detroit Edison	Fermi 2	January 1991	Three Year Capacity Factor	None to Date	Banked reward and penalty	2-32
OHIO: Performance Standard	Toledo Edison	Davis-Besse; Perry 1; and Beaver Valley 2	1981	Composite Measure	None to Date	Subjective denial of under collected system loss adjustment	2-45
	Cleveland Electric Illuminating	Davis-Besse; Perry 1; and Beaver Valley 2	1981	Composite Measure	None to Date	Subjective denial of under collected system loss adjustment	2-45
	Ohio Edison	Perry 1 and Beaver Valley 1 & 2	1981	Composite Measure	1/85-6/85 Denied $20K	Subjective denial of under collected system loss adjustment	2-45
OHIO: Nuclear Performance	Toledo Edison	Davis-Besse; Perry 1; and Beaver Valley 2	January 1988	Operating Availability Factor	None to Date	Banked reward and penalty	2-45
	Cleveland Electric Illuminating	Davis-Besse; Perry 1; and Beaver Valley 2	January 1988	Operating Availability Factor	None to Date	Banked reward and penalty	2-45
	Ohio Edison	Perry 1 and Beaver Valley 1 & 2	January 1988	Operating Availability Factor	None to Date	Banked reward and penalty	2-45

TABLE 3.2. (continued)

REGION III (continued)

Regulatory Authority: Program Classification	Utility	Nuclear Unit	Effective Date	Performance Criterion	Recent Reward/ Penalties	Comments/ Type of Program	Page
ILLINOIS: Rescinded Program	Commonwealth Edison	Dresden 2 & 3; LaSalle County 1 & 2; Zion 1 & 2; Bryon 1 & 2; Braidwood 1 & 2; Quad Cities 1 & 2; and Carroll County	Rescinded December 1989	Fuel Costs	N/A	Reward	2-21

TABLE 3.2. (continued)

REGION IV

Regulatory Authority: Program Classification	Utility	Nuclear Unit	Effective Date	Performance Criterion	Recent Reward/ Penalties	Comments/ Type of Program	Page
ARKANSAS: Nuclear Performance	AR Power & Light	Arkansas Nuclear 1 & 2	1980; Revised 1983	Annual Capacity Factor	'89 Reward $480K	Reward and Penalty	2-3
TEXAS: Proposed Program	El Paso Electric	Palo Verde 1, 2 & 3	Proposed 1987	Capacity Factor	N/A	Reward and Penalty	2-50

TABLE 3.2. (continued)

REGION V

Regulatory Authority: Program Classification	Utility	Nuclear Unit	Effective Date	Performance Criterion	Recent Reward/ Penalties	Comments/ Type of Program	Page
CALIFORNIA: Performance Based Revenues	Pacific Gas & Electric	Diablo Canyon 1 & 2	July 1988	Generation and Expenses	N/A	Generation determines revenues	2-5
CALIFORNIA: Nuclear Performance	Southern CA Edison	SONGS 1, 2 & 3 and Palo Verde 1, 2 & 3	1986, 1983, 1984, 1986, 1986, and 1988	Cycle Capacity Factor	SONGS 2 Cycle 3 Reward 1.3M; SONGS 3 Cycle 3 Reward $400K; Palo Verde 1 Cycle 2 Penalty $5.3M	Reward and Penalty	2-8
	San Diego Gas & Electric	SONGS 1, 2 & 3	1986, 1983, and 1984	Cycle Capacity Factor	SONGS 2 Cycle 3 Reward $353K; SONGS 3 Cycle 3 Reward $134K	Reward and Penalty	2-8
ARIZONA: Construction Cost Cap	AZ Public Service	Palo Verde 1, 2 & 3	Initiated 1984	Total Cost	None to Date	$2.86B Construction Cost Cap	2-2
NEW MEXICO: Nuclear Performance	El Paso Electric	Palo Verde 1 & 2	January 1987	Annual Capacity Factor	'89 Penalty $1.5M	Reward and Penalty	2-38
NEW MEXICO: Nuclear Performance	Public Service of NM	Palo Verde 1 & 2	May 1990	Cycle Capacity Factor	None to Date	Reward and Penalty	2-40

TABLE 3.3. Classification of Incentive Programs

Incentive Classification	Regulatory Authority	Utility	Nuclear Unit	Effective Dates
Nuclear Performance Incentive Programs	Arkansas PSC	AR Power & Light	Arkansas Nuclear 1 & 2	1980; Revised 1983
	California PUC	Southern CA Edison	SONGS 1, 2, & 3 and Palo Verde 1, 2, & 3	1986, 1983, 1984, 1986, 1986, & 1988
		San Diego Gas & Electric	SONGS 1, 2, & 3	1986, 1983, & 1984
	Florida PSC	FL Power	Crystal River 3	September 1980
		FL Light & Power	St. Lucie 1 & 2 and Turkey Pt. 3 & 4	September 1980
	Georgia PSC	Georgia Power	Hatch 1 & 2 and Vogtle 1 & 2	January 1989
	Massachusetts Department of Public Utilities	Boston Edison	Pilgrim	November 1989
	Michigan PSC	Detroit Edison	Fermi 2	January 1991
	New Jersey Board of Public Utilities	Public Service Electric & Gas	Salem 1 & 2; Hope Creek; and Peach Bottom 2 & 3	January 1987; Revised 1990
		Jersey Central Power & Light	Oyster Creek and Three Mile Island	March 1987; Revised 1990
	New Mexico PSC	El Paso Electric	Palo Verde 1 & 2	January 1987
	New Mexico PSC	Public Service of NM	Palo Verde 1 & 2	May 1990

TABLE 3.3 (continued)

Incentive Classification	Regulatory Authority	Utility	Nuclear Unit	Effective Dates
Nuclear Performance Incentive Programs (continued)	Public Utilities Commission of Ohio	Toledo Edison	Davis-Besse; Perry 1; and Beaver Valley 2	January 1988
		Cleveland Electric Illuminating	Davis-Besse; Perry 1; and Beaver Valley 2	January 1988
		Ohio Edison	Perry 1 and Beaver Valley 1 & 2	January 1988
	Pennsylvania PUC	Philadelphia Electric	Limerick 1 & 2; Salem 1 & 2; and Peach Bottom 2 & 3	April 1990

TABLE 3.3. (continued)

Incentive Classification	Regulatory Authority	Utility	Nuclear Unit	Effective Dates
Utility Performance Standard Programs	Connecticut	CT Light & Power	Millstone 1, 2, & 3 and CT Yankee	July 1979
	Maryland	Baltimore Gas & Electric	Calvert Cliffs 1 & 2	January 1988
	Massachusetts	Boston Edison	Pilgrim	1981; Revised 1985
		Western MA Electric	Millstone 1, 2, & 3	1981; Revised 1985
	Michigan	Consumers Power	Palisades and Big Rock Point	1983
		Indiana/Michigan Power	Cook 1 & 2	1983
	North Carolina	Carolina Power & Light	Brunswick 1 & 2 and Robinson	1987
		Duke Power	McGuire 1 & 2; Oconee 1, 2, & 3; and Catawba 1	1987
		VA Electric & Power	Surry 1 & 2 and North Anna 1 & 2	1987
	Ohio	Toledo Edison	Davis-Besse; Perry 1; and Beaver Valley 2	1981
		Cleveland Electric Illuminating	Davis-Besse; Perry 1; and Beaver Valley 2	1981
		Ohio Edison	Perry 1 and Beaver Valley 1 & 2	1981
	Virginia	VA Electric & Power	Surry 1 & 2 and North Anna 1 & 2	January 1979

TABLE 3.3. (continued)

Incentive Classification	Regulatory Authority	Utility	Nuclear Unit	Effective Dates
Utility Economic Incentive Program	New York	Rochester Gas & Electric	Ginna & Nine Mile 2	1985
		Niagara Mohawk	Nine Mile 1 & 2	1985
		NY State Electric & Gas	Nine Mile 2	1985
	North Carolina	Carolina Power & Light	Brunswick 1 & 2 and Robinson	1987
		Duke Power	McGuire 1 & 2; Oconee 1, 2, & 3; and Catawba 1	1987
		VA Electric & Power	Surry 1 & 2 and North Anna 1 & 2	1987
	Virginia	VA Electric & Power	Surry 1 & 2 and North Anna 1 & 2	January 1979

TABLE 3.3 (continued)

Incentive Classification	Regulatory Authority	Utility	Nuclear Unit	Effective Dates
Performance Based Revenues	California PUC	Pacific Gas & Electric	Diablo Canyon 1 & 2	July 1988
Construction Cost Cap	Arizona Corporation Commission	Arizona Public Service	Palo Verde 1, 2, & 3	Initiated November 1984
Construction Cost Cap	Pennsylvania PUC	Philadelphia Electric	Limerick 2	Concluded 1990
Proposed Incentive Program	Texas PUC	El Paso Electric	Palo Verde 1, 2, & 3	Proposed 1987
Rescinded Incentive Program	Illinois Commerce Commission	Commonwealth Edison	Dresden 2 & 3; LaSalle County 1 & 2; Zion 1 & 2; Bryon 1 & 2; Braidwood 1 & 2; Quad Cities 1 & 2; and Carroll County	Rescinded December 1989

TABLE 3.4. Summary of Incentive Programs Discontinued as of 1989

Regulatory Authority: Program Classification	Utility	Nuclear Unit	Effective Dates	Performance Criterion	Comments/Type of Program
ARIZONA: Nuclear Performance	AZ Public Service	Palo Verde 1	Effective 1986; Discontinued 1989	Annual Capacity Factor	Reward and Penalty; '87 Penalty 1.7M; '88 Penalty $19K
CALIFORNIA: Nuclear Incentive	Pacific Gas & Electric	Diablo Canyon 1 & 2	Discontinued 1987	Capacity Factor	Reward and penalty; '86 reward $14.0M; Settlement of disputed construction costs established Performance Based Pricing
COLORADO: Nuclear Incentive	Public Service of CO	Ft. St. Vrain	Discontinued 1986	Annual Capacity Factor	Penalty; Settlement agreement paid accumulated penalties and discontinued incentive plan
VIRGINIA: Economic Incentive	VA Electric & Power	Surry 1 & 2 and North Anna 1 & 2	Concluded 1985	Fuel Costs	Rate of return on equity; Three-year trial basis
FLORIDA: Nuclear Incentive	FL Power & Light	St. Lucie 2	Effective 1983; Discontinued 1984	Annual Capacity Factor	Reward and penalty; Reward $3.5M
MICHIGAN: Economic Incentive	Consumers Power	Palisades and Big Rock Point	Not Available	Availability	Rate of return on equity
MISSISSIPPI: Economic Incentive	System Energy Resources	Grand Gulf	Concluded 1989	Multiple Performance Parameters	Allowed revenues; fossil generation trial program
NEW JERSEY: Construction	Public Service Electric & Gas	Hope Creek	Concluded 1987	Total Construction Costs	Reward and penalty; $4.0B rate base allowance;$516M disallowance
NEW MEXICO: Economic Incentive	Public Service of NM	Palo Verde 1	Discontinued 1989	Excess Capacity	Disallowed due to the accounting treatment of the inventory capacity

TABLE 3.4. (continued)

Regulatory Authority: Program Classification	Utility	Nuclear Unit	Effective Dates	Performance Criterion	Comments/Type of Program
NEW YORK: Construction	Niagara Mohawk	Nine Mile 2	Concluded 1986	Total Construction Costs	$6.5B total construction costs; $1.2B; disallowance
NEW YORK: Nuclear Performance	Rochester Gas & Electric; Niagara Mohawk; and Consolidated Edison	Ginna; Nine Mile 1 & 2; and Indian Point 2	Withdrawn 1989	NRC SALP Ratings & Fines	Proposed to bonuses to nuclear plant workers
OREGON: Economic Incentive	Portland General Electric	Trojan	Discontinued 1987	Fuel Costs	Reward and penalty

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This report supersedes NUREG/CR-5509, issued in December 1989.

11. ABSTRACT (200 words or less)

The Nuclear Regulatory Commission (NRC) monitors incentive programs established by state regulators in order to obtain current information and to consider the potential safety effects of the incentive programs as applied to nuclear units. The current report is an update of NUREG/CR-5509, Incentive Regulation of Nuclear Power Plants by State Public Utility Commissions, published in December 1989.

The information in this report was obtained from interviews conducted with each state regulator and each utility with a minimum entitlement of 10%. The agreements, orders, and settlements from which each incentive program was implemented were reviewed as required. The interview and supporting documentation form the basis for the individual state reports describing the structure and financial impact of each incentive program.

The programs currently in effect represent the adoption of an existing nuclear performance incentive program proposal and one new program. In addition, since 1989 a number of nuclear units have been included in one existing program; while one program was discontinued and another one concluded.

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