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CONSTRUCTION COST OVERRUNS IN ELECTRIC UTILITIES: SOME TRENDS AND IMPLICATIONS

FOREWORD

The bylaws of the National Regulatory Research Institute state that among the purposes of the Institute is:

> ... to carry out research and related activities directed to the needs of state regulatory commissioners, to assist the state commissions with developing innovative solutions to state regulatory problems, and to address regulatory issues of national concern.

This study - the third in our series of Occasional Papers - helps meet that purpose. The existence of substantial and persisting cost overruns in the construction of utility plants is a problem for utility companies, ratepayers, and regulators alike. How much of these overruns is properly attributable to "inflation" and how much to other causes and what might be done about it are questions of very real currency.

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INTRODUCTION AND SUMMARY OF FINDINGS

When the Shoreham 1 Nuclear Plant comes into service on Long Island it will have cost at least five times as much as first estimated. The cost of nuclear plants generally have increased an average of nearly 18 percent per year in the last decade, in an upward spiral that is one reason for diminished interest in this power source. However, the cost of coal-generating plant has risen as well, with new plants costing almost double what they did eight years ago, and further boosts already in view.

Cost increases at these rates create special problems for state utility regulators, who must weigh the benefits of constructing new plants according to a number of considerations. If early estimates are unreliable, the basis for reasoned decisions evaporates. Plants might be built whether or not they eventually make sense either to utilities or their regulators.

The purpose of this report is to sort through the record of increases and overruns and clarify their meaning. Essentially, we are interested in two questions: Why have plant costs been going up so much, and what can be done about it?

We have attempted to answer the first question by recognizing all relevant influences: the incentives of utilities, the common problems of inflation and cost estimation, and regulatory developments that have affected major power sources. The second question we have attempted to answer from the viewpoint of both utilities and regulators. Our findings are summarized below:

Investment Incentives

Cost-of-service regulation is an imperfect way of encouraging efficient capital choices. Indeed, under certain conditions, regulation may actually encourage overspending on the fixed plant that goes into the rate base. These conditions, and the perverse incentive known as the "Averch-Johnson" effect, are, however, considerably less likely now than they might once have been. Utilities' profits on rate-base investment remained virtually flat in the past decade, even as inflation and interest costs accelerated.

Nevertheless, a regulatory regime that ties revenues to plant outlays leaves doubtful incentives for the vigorous control of these outlays. In the case of utilities, suspect incentives have joined with a record of underestimated costs to provoke attention.

General Cost Estimation Problems

Industrial companies customarily estimate the costs of new plants under uncertain conditions. Even in the earliest stages of planning, they expect to come within 20 to 40 percent of the actual costs of each facility. More important, they expect to make unbiased estimates, so that on average at least, they forecast capital needs with rough accuracy.

In recent years, and especially among public or regulated enterprises, much worse estimation errors have cropped up. Even adjusted for inflation, estimated costs of public construction have often been less than half of eventual outlays. Most of this error traces to an inadequate definition of the scope of a project at the outset. There is also a bias toward underestimation when cost estimates are used to promote a project.

Inflation

Most recent cost estimates have included some expected increase due to inflation. However, these can still be thrown off when inflation in relevant labor and material markets is more rapid than anticipated. The costs of construction "inputs" have moved up more rapidly than economywide prices, increasing at an average rate of more than 10 percent a year in the mid-1970's. During the period studied, the rate of increase accelerated twice: once around 1966 and again in the embargo year of 1973.

A utility cost estimator using the past to project the future could, at those two points, have erred by at least 3 percent per year. In long-lead-time projects, that error would account for cost increases from 40 to 50 percent above initial estimates.

Nuclear Plant Costs

As is well known, the forecasting record for nuclear plant costs is miserable. More than two-thirds of the plants reviewed cost more than double their initial estimates. This record is worsening, moreover, as new plants come into service. Four plants in, or scheduled for, operation after 1976 overran initial estimates by better than 3.8 to 1.

Inflation explains only a portion of this record. In a typical recent overrun, unanticipated escalation and interest charges account for little more than one-third of the total overrun. The remainder, up to $500 million for a typical nuclear unit coming on-line in the early 1980's, traces in one way or another to changing safety requirements.

The real, or inflation-adjusted, cost of building nuclear capacity increased about 14 percent per year for plants completed from 1971 to 1978, for a total rise of more than $500 per kilowatt. A part of this increase bought the improved safety systems sought by regulators, such as earthquake protection and better emergency-cooling systems. A part paid for the inefficiency of installing these systems once plants had already been designed and construction was under way. Up to 10 percent of plant costs might have been saved by equally tough, but more stable, design criteria.

Finally, a part of this increase was probably the result of management practices inadequate to a very difficult construction environment. We and others have estimated that from 4 to 8 percent of some plants' costs might have been saved by improved cost and schedule control, better work-force utilization, and the like. It is less easy to say, however, whether these improved practices could reasonably have been expected in past construction—when the problems we now know about were first being encountered.

The future of nuclear costs, like that of nuclear power, is extraordinarily uncertain. If new plants could be built under today's design requirements, they might cost from $800 to $1,000 per kilowatt in 1979 dollars. However, if safety rules continue to be revised, costs near $1,400 per kilowatt are possible.

These cost trends, and the lack of a policy consensus that underlies them, make new nuclear starts extremely doubtful. Even retrofitting existing nuclear plants to match upgraded safety requirements will probably cost at least $50 million and perhaps as much as $200 million per plant.

Coal Cost Trends

The overrun record for coal plants has been more moderate. Recent coal plants have come in at from 40 to 60 percent above earlier estimates. That is a big increase, but the greater part of it can be explained by the increase in construction costs and higher financing charges.

Cost increases due to regulatory requirements for new coal plants generally have been anticipated by estimators. Most of these requirements set well-defined performance criteria and envision the use of specific pieces of equipment. On an individual plant basis, most of the major requirements possible can be known and taken into account in planning stages.

Nevertheless, tougher environmental rules have increased the costs of coal-fired units substantially. Clean air standards are paramount but are being joined by new rules on water pollution, noise abatement, and solid waste disposal. Taken together, these rules have escalated the average cost of generating electricity from coal by up to 8 percent per year from 1971 to 1978, or as much as $240 per kilowatt in today's dollars.

These upward cost pressures will continue. With the Clean Air Act Amendments of 1977 now being implemented, new plant costs will probably rise by around another $400 per kilowatt by the late 1980s. Converting oil-fired units to environmentally acceptable coal burners will require from $100 to $450 per kilowatt, depending on the site and necessity for scrubbers.

Transmission and Distribution Costs

These costs represent a large but stable element of utilities' plant outlays. Over the past decade, costs for most types of T&D have risen at or below rates of construction costs. Overhead distribution lines are the exception and account for nearly one-third of total T&D outlays. Costs for these lines have been going up at about 15 percent per year. Though the distribution increase is high, the overall trend in T&D is not worrisome or surprising.

Utilities' Management Practices

By far the largest portion of utilities' plant cost increases have been forced upon them by external events: changed regulation, inflation, and inflation-driven interest rates. The sums involved are so large however—retrofits cost as much as entire plants once did—that any costs savings achievable ought to be sought by utilities and pressed for vigorously by regulators.

There are two basic ways utilities can control the cost of a construction activity. They can write a contract that provides effective incentives for efficient performance, or they can closely control the activity themselves.

In power plant construction, effective incentives require fixed or "incentive price" contracts with appropriate escalator clauses. To use these types of contracts, the scope of work must be specified quite firmly, with at least 80 percent of the job's engineering done when the contract is bid. If the scope is firm, use of escalator clauses, based on published cost indices, will relieve the contractor of inflation uncertainty yet leave him with adequate performance incentives.

Because of unpredictability in project scope, traceable in large part to regulatory requirements, much recent power plant construction has been conducted through cost-plus contracts. These contracts exert little incentive for efficient work. Often, too, the work has been poorly monitored and controlled by the utility.

That is changing, as utilities evolve more active management techniques. These techniques seek to control costs by (1) breaking many jobs up into small, well-defined work packages that can be handled through incentive contracts, and (2) establishing sophisticated information tools for monitoring, evaluating, and controlling the overall project.

Under the more active approach, utilities must take responsibility for up to 88 percent of the management functions and 81 percent of the construction functions that once were mostly delegated to outside companies. This sort of responsibility requires progressively increased experience, acquired over several projects.

Utilities' staff must also grow apace. For a major utility, in-house construction staff may have to grow tenfold to make active management effective. To preserve experience, large staffs may need to be retained even when building slows.

Some Regulatory Choices

Improved management practices ought to be encouraged by regulators in both ongoing and future building projects. As plants now under construction are completed, their costs ought to be scrutinized closely. Where unnecessary cost incurrences can be identified, their disallowance will exert healthy pressures on future spending decisions. Where, however, unnecessary expenditures cannot be identified with reasonable precision, simply being tough in disallowing costs is not helpful.

Fortunately, tools for judging the reasonableness of costs are improving. Project audits are giving specialized companies expertise in power projects and providing more representative data on such crucial items as work-force utilization and productivity. These tools might be further enhanced if cost-accounting systems could be consolidated and standardized to evaluate performance better.

In reviewing new plant proposals, regulators' options are more varied. Tougher standards for acceptable management practices can be applied fairly. A cost and schedule monitoring system could be set up for the utility itself to report on major projects to regulators. Such a system might promote heightened cost consciousness on the part of the utility, and it would surely put regulators in a better position for their eventual review of project costs.

Incentive return plans might also be desirable for new projects. Under this approach, the return eventually allowable on a plant would be tied to the proximity of estimated to actual costs. To be effective, incentive returns require that costs be predictable within reasonable bounds, a condition that is probably satisfied by many coal plants and almost certainly not satisfied by nuclear plants. This approach also requires that initial estimates be realistic and not easily inflated.

Organization of the Report

The report is organized in three chapters. The first reviews the logical and practical background of utilities' plant-spending incentives. Its purpose is to discover what traditional arguments about these incentives are still relevant in a world of high inflation and special regulatory practices to counter it.

Chapter Two takes a detailed look at the plant cost record. Introductory sections discuss the problems of cost estimation and inflation generally. The remaining sections treat nuclear, coal, and transmission and distribution costs.

The final chapter looks at what utilities and regulators might do about increasing costs. It discusses contract and management choices available to the utility, and regulatory choices available to utility commissions.

Chapter One

REGULATORY BACKGROUND

A. INTRODUCTION

Regulation of electric utilities confronts a central problem that can never be solved entirely: making a natural monopoly behave as if it were a competitive enterprise. Depending upon the part of this problem they choose to emphasize, regulators will improve one aspect of utility performance only to allow, or inadvertently encourage, undesirable side effects.

Regulators have traditionally aimed for the equity quality of competitive markets, preventing utilities from reaping excessive profits by virtue of their position as sole suppliers of essential services. Thus, ratemaking rules are grounded on costs of service, including the costs of building and operating plants and a reasonable return on capital.

Competitive markets are supposed to be "efficient," too. Efficiency considerations have always played some part in regulatory policy and began to receive more serious and formal consideration in the early 1960s. The most important aspect of efficiency is the setting of overall output of a good or service at a level that balances its cost of production with its value to customers. In the case of electricity, it is desirable that utilities price power in line with the marginal costs of providing it and be able, and willing, to make the necessary investments.

Equity and output efficiency form the background of this report, but not its concern. Rather, we focus on the efficiency with which inputs are brought to the process of generating electricity. Two important types of input efficiency are static and dynamic. The first means that a company chooses the least-cost way of providing a service from the choices it has available to it at any particular time. The second means that the company continues, through research and innovation, to look for better choices over time. Both types of input efficiency are linked to plant cost control. The remainder of this chapter explains why and how current regulatory practices may influence efficiency and plant costs.

B. PROBLEMS OF COST-OF-SERVICE REGULATION

Competitive markets achieve efficiency by a process of search and survival. Taking selling prices given by the market, companies attempt to minimize costs by choosing the right level of output (scale), and the best mix of various types of capital labor, and raw materials, such as fuel. Based on experience, they change and refine their choices, learn new techniques, and reduce costs further. Companies that are good at this earn returns competitive with other investment opportunities and are able to stay in business; others usually are not.

General Problems

Competitive markets generate competitive or fair profits only on average, by a process in which many make less or more for a while. Companies that choose an improved process first may make much higher profits than they would need to attract new investment. Conversely, companies that choose unwisely can make less. The opportunity for gain above competitive norms and the real possibility of loss is what motivates both managerial efficiency and change.

Regulation seeks to limit returns to competitive levels but does not tightly link a utility's performance to its owners' financial position. It can thus dilute managers' incentives to choose efficient inputs and to search continually for better choices. One reason regulation may fail to motivate efficient management lies in the application of the rate-of-return standard itself. Another lies in the possibility that the allowed rate of return, or the selection of the rate base, may bias management's choices.

If regulators were successful in assuring a fair rate of return continuously, there would be little incentive for management to economize on costs. All investments would earn a satisfactory return even if they were wasteful or if clearly preferable alternatives existed. A cost-plus attitude would permeate all capital and cost-incurring decisions. Because electric rates are fixed for the periods between increase applications, utilities have some incentive to minimize costs controllable in the short term. However, the cost of a new generating plant is usually the basis for a rate increase application. This cost is not simply a cash outlay but helps to determine a company's future revenue streams. Decisions on investments for a plant are thus vitally affected by the rate treatment expected.

If a company expects to receive revenue increases less than needed to finance a new plant, plant investment would eventually cease. If a company expects to receive adequate profits on all plant costs, without question, then ordinary financial motives would exert very weak pressures to minimize or control plant costs. Engineering criteria may encourage efficient design, or the desire to retain or increase customers (by keeping costs and rates low) might be the most important incentives for cost control. This weakness of financial incentives for cost control constitutes the central and largely unavoidable problem of regulating rates of return on plant costs.

Finally, if a company expects to receive more profits on new plant construction than it requires to finance them, financial motives might operate perversely, encouraging overspending on capital plants. This possibility, often called the Averch-Johnson effect, raises a chronic worry about utility regulation.

Averch-Johnson Effects

Electric utilities serve a variety of objectives and restraints, including engineering requirements, regulatory mandates, internal organizational goals, and the interests of their investors. Financial theory indicates that investors' interests are best served when a private company makes all investments that earn at least its marginal cost of capital. The marginal cost of capital is composed of the incremental costs of both equity and debt capital (in their most desirable combination) and forms a kind of "indifference" point for management. Projects that earn more should be undertaken, those earning less should be rejected.

Utilities' earnings on a plant are affected not only by its costs and performance but by its regulatory treatment. Harvey Averch and Leland Johnson pointed out a tendency in regulation that might encourage overspending on fixed plant and equipment. Briefly, if regulators allow returns in excess of the marginal cost of capital to rate-base investment, equity investors could profit from otherwise inefficient fixed investment that is included in the rate base. Utilities might tilt spending toward plant when increased labor or fuel spending might serve demand more efficiently; or ignore new opportunities in plant design; or develop a general lack of concern and control over project outlays once construction had begun.

Averch-Johnson effects thus lie at the heart of much anxiety about utility spending and, if forceful, would clearly affect overrun experience. In order for these effects to create incentives for overspending on plants, however, several important conditions must hold. [1] First, of course, public utility commissions must be guided primarily by a rate of return applied to the rate base standard in setting rates. If commissions operate differently, for instance by controlling equity returns or simply seeking to retard rate increases, utilities' investment incentives are more complicated.

Second, as noted, the allowed rate of return must exceed the marginal costs of capital to the company. This condition was widely agreed to prevail in the 1950s and early 1960s.

Third, the allowed rate of return must be translatable into an achievable rate of return. This means that long delays in approval of rate increases are not anticipated, nor is disallowance of any incurred costs. This condition is favored by the congenial relations between regulators and regulated that is more likely in a declining cost environment such as prevailed for most of the period before the early 1970s.

In order for utilities to raise rates to achieve allowed returns on new investments, a final condition must be met. Demand for at least some classes of service must be sufficiently inelastic to permit rate increases without offsetting volume reductions. This condition was also favored by a declining cost environment in which new customers were anxious to obtain service and existing customers reluctant to disconnect.

Averch-Johnson effects thus rest on a number of conditions that appear most plausible in the stable cost and regulatory environment long past. Recent studies provide some indication that utilities overinvested in fixed plant in the past, but the evidence, even for earlier periods, is not conclusive.

Economist Robert Spann found evidence of a tilt toward fixed plant in electric utility investments from 1959 to 1963. [2] Leon Courville reached a similar conclusion using generating plant data from 1948 to 1966. [3] Courville also estimated that, as of 1962, overinvestment was adding about 12 percent to the cost of generating the nation's electricity. On the other hand, Baron and Taggart have argued, using 1970 data, that utilities were in fact undercapitalized, that is, relied too little on fixed plant and equipment to generate electricity. [4]

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[1] Alfred J. Kahn, *The Economics of Regulation Principles and Institutions*, Vol. II, (New York: Wiley, 1971), pp. 49-59.
[2] R. M. Spann, "Rate of Return Regulation and Efficiency in Production: An Empirical Test of the Averch-Johnson Thesis," *The Bell Journal of Economics* 5 (1974): 38-52.
[3] L. Courville, "Regulation and Efficiency in the Electric Utility Industry," *The Bell Journal of Economics* 5 (1974): 53-74.
[4] D. P. Baron and R. A. Taggart, "A Model of Regulation under Uncertainty and a Test of Regulatory Bias," *The Bell Journal of Economics* 8 (1977): 151-168.

The evidence so far gathered does not resolve the question of investment bias created by regulation. An answer found valid for one period would not, moreover, provide a sure guide to utilities' incentives or performance in another. Several changes in the regulatory and economic environment make it less likely that Averch-Johnson effects currently influence utility planning. Public utility commissions have intensified their scrutiny of plant expenditures and rate increase requests based on them. It is less credible now that a utility planner should expect the smooth and immediate inclusion of new generation facilities in the rate base. Utility commissions have also come to focus on equity as well as overall returns; and, with higher rates, may have come more resistant consumers, possibly increasing demand elasticities.

The key logical underpinning of the Averch-Johnson effect is still, however, the excess of allowed (and achievable) rate of return over a utility's cost of capital. The relationship between these variables has been much affected by the extraordinary inflation of the last decade and by regulators' attempts to deal with inflation. Before reviewing evidence of the changes in utility performance, we will look at some of the specific issues regulators have had to address.

C. DEALING WITH INFLATION

Inflation is a substantial and persistent rise in the general level of economywide prices. It is marked by an increasing trend in average prices and may be accompanied by movements in the prices of particular items that diverge sharply, at least for a while, from this average trend.

Interest rates, or the price of money, are particularly important. They are critical in plant-spending decisions and are heavily influenced both by inflation and policies to fight it. Besides interest rates, inflation affects all the costs that go into a ratemaking calculation: plant costs, fuel and other operating expenses, and rates of return.

If not accounted for, inflation could destroy both incentives to invest and the ability to attract capital by making credible promises of repayment. However, it is also possible to overadjust for inflation, double counting its effects or unnecessarily hastening its impact on consumers.

Public utility commissions have had to balance competing concerns in dealing with inflation and have reached a variety of remedies. Commissions must usually pay significant attention to questions of timing and equity. Our focus, though, is on the potential effects of these remedies, or lack of them, on the incentives utilities have to invest efficiently in new power plants.

Fair Value and Nominal Returns

Inflation pushes up both the replacement costs of capital equipment and the rates of return needed to raise new capital. However, if regulators adjust both rate base and return standards for inflation, companies will be overcompensated for increasing prices.[5]

Utilities can be compensated adequately for the inflation of investment costs by one of two basic approaches: increasing the rate base from historical costs to current replacement value while maintaining a necessary real return, or continuing to value the rate base at historical costs while adjusting return rates to reflect inflation.

Either approach, if adhered to consistently, should maintain adequate investment incentives. Present value calculations will arrive at equivalent results, returning original investment, inflation compensation, and a real return for investors' risk and deferred consumption. Few utility commissions have revalued plant at current costs, however.[6] Most commissions recognize inflation by adjusting returns in one fashion or another. The effect of this approach on investment incentives depends on the method of adjustment and its interaction with other regulatory policies such as those governing ongoing construction and tax provisions.

CWIP and AFUDC

Two basic choices are available in treating ongoing construction costs. Traditionally, an account was kept that reflected the financing costs incurred during a project. When the project went into operation, its value in the rate base included this allowance for funds used during construction (AFUDC). Before inclusion in the rate base, the AFUDC account on utility earnings statements told investors that returns were anticipated, though not yet received, on projects under way.

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[5] R. E. Anderson; "Compensation for Inflation under Alternative Regulatory Formulas: A Rejoinder," *Public Utilities Fortnightly*, December 6, 1979, pp. 32-35.

[6] J. R. Jones, "Inflation and Regulation," *Public Utilities Fortnightly*, August 4, 1977, pp. 17-20.

The AFUDC approach conformed to the principle that the rate base should include only those facilities actually serving consumers; and, if done properly, it assured that investors could expect to eventually recoup the capital charges adequate to justify investment. Because of inflating plant costs, delays, and soaring interest rates, AFUDC began to represent an increasing portion of utilities earnings. If these returns were indeed certain, then only a utility's cash position would have been affected; but, coincident with the increase in AFUDC accounts, plant costs were also coming under more strict commission review. In addition, AFUDC accounts representing nuclear plants had to be interpreted in light of the increasingly complicated and uncertain licensing rules applicable to these plants. Both developments jeopardized the certainty of AFUDC earnings.

Most utility commissions now permit, at least in some circumstances, the inclusion of Construction Work in Progress (CWIP) in the rate base. Under the CWIP approach, capital committed to ongoing construction may earn a return before the completion of the plant. According to a recent survey, CWIP was requested in more than 60 percent of the rate increase applications filed in 1977 and was allowed in more than half the cases where it was requested. At least 34 state commissions have granted CWIP in some cases, though often only in special circumstances such as financial stress or in the funding of pollution control facilities.[7]

CWIP has become a widely used alternative to the more traditional AFUDC approach. It is intended to improve a utility's financial position by affecting the timing rather than the eventual value of revenues. The use of CWIP might affect investment incentives in several ways. CWIP could be used as a means of increasing the rate of return to be earned on a project. This would occur if the return allowable on rate-based investment was different from that imputed to funds used during construction. However, if both rates are equivalent (taking into account any tax differences), the choice between CWIP and AFUDC should not affect the overall return on a project.

Allowing CWIP could also reduce the costs of capital to a utility, reflecting the improved confidence of investors in increased cash flow and coverage of debt service obligations. The likelihood of this effect depends on the validity of the original argument that more prompt revenue generation is required to reassure investors and bondholders. If unadjusted for, this reduction in capital costs could distort the relationship between these costs and allowed rates of return. Currently, most utility commissions probably do not adjust adequately for capital cost reductions that CWIP may bring. It is far from clear, however, that these reductions are significant relative either to other return criteria or the imprecision of capital cost estimation in general.

Finally, the use of CWIP might affect the certainty or completeness with which new project costs are included in the rate base. If CWIP treatment prejudices commission review of the prudence of project expenditures, this would obviously dilute the incentives to control project costs. One way it might do so is by creating a legal precedent on the acceptability of early project costs. Commission efforts to scrutinize these costs more closely when the project is complete might be deterred by this precedent. On the other hand, CWIP could serve as a useful tool for maintaining investor confidence about the financial health of a utility during lengthy regulatory reviews.

Tax Issues

Another set of regulatory choices that affects the timing of utilities' cash flows (but affects investment incentives only under certain conditions) stems from federal tax policy. Corporate income taxes are costs of doing business and were traditionally treated as current expenses by state utility commissions. Rates were set so that, after current tax payments were deducted, revenues were sufficient to pay other current costs and justify plant investment.

Special provisions in the corporate tax code have been used to encourage industrial investment for several decades. These provisions, which currently include accelerated depreciation schedules and investment tax credits, associate with each capital investment a reduction and/or deferral in the investing company's tax obligation.

Accelerated depreciation and investment tax credits have been available to utilities as well as to nonregulated industrial companies. If the easing of tax burdens had been ignored, the utility would have had the full benefit of the change in provisions. However, this would be equivalent to raising the returns allowable to utilities for no other reason than a change in federal economic policy. This approach was not adopted.

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[7] W. F. Muhs and D. A. Schauer, "State Regulatory Practices with Construction Work in Progress," *Public Utilities Fortnightly*, March 27, 1980, pp. 29-31.

In the 1960s, many utility commissions treated special tax provisions as simply reducing the current tax payments made by a utility. Federal tax benefits were "flowed through" to consumers, in the form of reduced rates, as they occurred. This approach left utilities in the same position as before. Though preferred by consumers and many commissions, it was discouraged by the 1969 Tax Reform Act.

The 1969 act required that, unless flowthrough was already being used by a commission, the tax benefit associated with new capital investments be normalized over the lives of these investments. In normalization, the reduction in taxes, though concentrated soon after the purchase of an asset, is compensated for by rate reductions distributed over the asset's useful life.

By 1977, only six states were still requiring flowthrough of accelerated depreciation benefits, and only three states flowed through investment tax credits.[8] Clearly, deferring the rate relief made possible by reduced taxes (after the tax reductions themselves have been reaped) shifts both the timing of consumer gains and their distribution among consumers. Under normalized tax treatment, utilities have more capital, earlier, with which to make investments.

The effect of normalized accounting on investment incentives is less straightforward. Normalization schedules can assure that the deferral in rate reduction is balanced by having smaller reductions. The lag between initial tax gains and rate reductions is adjusted for at an appropriate cost of capital. If this is done, the profitability of an individual investment should be no different under normalization from that under flowthrough. Since the latter practice neutralizes changes in federal tax policy, the profit standards initially set by regulators should also be maintained.

At present, it appears that most states normalize the benefits of accelerated depreciation in a way that neutralizes its effects on the profit incentives for new investment. However, current methods of normalizing investment tax credit benefits may not adjust fully for the effects of this provision; because these methods fail to recognize the credit's effects on both appropriate rate base and depreciation charges, utilities may still be able to earn higher returns by virtue of the credit.[9]

Apart from this conditional impact on profitability, normalized tax treatment may exert another influence on investment choices. Like CWIP, tax normalization improves early cash flows. To the extent cash limitations impose restraints on utility planning, normalization helps ease these restraints.

Other Policies

In response to inflationary pressures, utility commissions have adopted a number of additional policies. Most significant by far, in terms of their impact on rates, are the fuel adjustment clauses now allowed by some 40 state utility commissions. From 1974 through 1977, use of these clauses resulted in revenue gains totaling nearly three times as much as those permitted by general rate increases.[10]

Though critically important both to consumers and to utilities' incentives for operating efficiency, fuel adjustment clauses could exert only an indirect force on plant investment decisions. By assuring the prompt passthrough of increased fuel costs, these clauses could, in principle, tilt investment decisions against plants if costs of the latter were subject to uncertain approval. This bias against capital plants would work against any proplant bias because of Averch-Johnson effects.

Many utility commissions attempt to dampen the effects of regulatory lag by allowing interim and pancaked rate increases or by using future test years for ratemaking decisions. The allowance of rate increases without complete commission scrutiny could improve a utility's financial position during delay periods. It could also affect the utility's initial decisions on investment by improving the likelihood that allowed returns will actually be earned during inflation. Finally, such procedures could, but generally do not imply an easing of the criteria under which rate applications are eventually judged.

The use of future rather than historical test years improves the realism of cost and load estimates used in ratemaking proceeding and does so to the benefit of utilities. If prior return standards are combined with more accurate anticipations of generating costs, the effect could be to improve the real returns achievable under regulation. Here again, though, the most likely effect is to improve the chances that allowable returns will actually be achieved.

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8 Testimony of D. W. Kiefer in *A Review of Selected Tax Expenditures: Investment Tax Credit, Hearings before the Subcommittee on Oversight, Committee on Ways and Means, U. S. House of Representatives*, March 28, 1979, Serial 96-78 (Washington: U. S. Government Printing Office), pp. 494-507.

9 Ibid.

10 D. N. Jones, "Regulatory Response to the Inflationary Environment: Some Costs and Gains," in *Analysis of Selected Financial Aspects of the Electric Utility Industry* (Columbus, Ohio: National Regulatory Research Institute, 1979), pp. II-5. For early evidence on a more comprehensive indexing, see A. Kaufman and R. J. Profozich, *The New Mexico Cost of Service Index: An Effort in Regulatory Innovation* also published by NRRI.

Fuel adjustment clauses, interim rates, and forecast test years are all attempts to minimize the impact of regulatory lag on utilities' real earnings. They are not aimed at plant investment and could plausibly affect plant decisions in only two basic ways: by holding up real returns on investment during a period of rapidly inflating operating costs or by easing the problem of raising capital. Neither effect would especially tilt investment toward fixed plant except as it removes unintended burdens on capital expenditures.

D. CURRENT INVESTMENT INCENTIVES

Inflation accelerated rapidly in the mid-1970s and did so again at the end of the decade. The various policies discussed above were often adopted after a delay and not always applied with perfect consistency. What counts in a decision on buying an asset, of course, is not the effect of a particular policy but the combined impact of economic conditions and all the rules expected to prevail over the life of the asset.

Neither of these influences can be characterized with certainty. For an independent observer, there are basically two ways of looking at utilities' investment incentives: according to how well they have actually done in the past and according to what returns regulatory commissions are now allowing in ratemaking cases.

Achieved Returns

Evidence abounds that the rapid price runup of the last decade cut the real, or inflation-adjusted, profitability of private utility companies substantially. In Table 1, three financial indicators are summarized for a selected group of utilities for the years 1970 through 1978. After summarizing inflation, the next two columns show the nominal return actually achieved on equity and on historical cost rate base.

Since inflation rose significantly, beginning in 1973, higher levels of nominal profitability would have been needed to maintain real earnings. Equity returns declined slightly over most of the period, however, reaching their lowest rate of 10.5 percent in 1974. Unless equity investors gained enough through the reduction in bond values to offset their own losses to inflation, they received diminished real returns on investment in this period.

TABLE 1
SUMMARY INDICATORS OF UTILITY PROFITABILITY, 1970–1978

Year	Inflation Rate	Achieved Return on Equity	Achieved Return on Rate Base	Average Price Earnings Ratio	Market to Book Ratio
1970	5.4%	12.4%	7.5%	11.7	1.33
1971	5.1	11.8	7.4	12.8	1.31
1972	4.1	12.1	7.6	10.8	1.16
1973	5.8	11.4	7.7	10.3	1.00
1974	9.7	10.5	7.5	8.0	.62
1975	9.6	11.4	8.3	7.0	.74
1976	5.2	11.2	8.3	8.6	.83
1977	6.0	NA	NA	8.3	.90
1978	7.3	NA	NA	NA	.79

Sources: Inflation rate is year-to-year change in GNP Implicit Price Deflator, *Economic Report of the President*, January, 1980; utility financial data for selected utilities, excluding holding companies, from D. N. Jones, "Regulatory Response to the Inflationary Environment: Some Costs and Gains," in *Analysis of Selected Financial Aspects of the Electric Utility Industry*, (Columbus, Ohio: National Regulatory Research Institute, 1979).

The return on rate base provides a simpler picture of the deterioration in real profitability in the mid-1970s, since interpretation of this indicator need not be clouded by inflation-induced transfers between bondholders and equity investors. Nominal returns on historical cost rate base were flat during most of the period of rapid inflation, rising only slightly toward its end. This means that total returns on the capital used to finance assets, adjusted for inflation, were sharply diminished.

The effect of these trends on equity investors is summarized in the next several columns of Table 1. The ratio between the market's evaluation of earnings and the book value of utility assets declined precipitously, reaching its lowest point in the embargo year of 1974 and recovering only partially since then. A similar trend is observable in the relationship between utility stock prices and reported earnings. (Similar indices for other industries also registered a decline during the period.)

These trends have several implications for regulatory policy. The most important for our purpose is this: During most of the last decade, utility planners were making new investment decisions while the profitability of past investments was being reduced by inflation and the fact that regulation did not fully adjust for it. Optimism about earning attractive returns on new plant must have been considerably dampened by this experience.

Allowed Returns

The second approach to assessing the investment planning environment is summarized in Table 2. The first two columns show the average rates of return on equity and historical cost rate base allowed by utility commissions in approving new rate increases each year. These return standards are used to calculate rates in procedures that vary greatly in their supporting assumptions, test periods, and prospects for achievement in practice. Nevertheless, the levels and trends in these standards underscore several important points.

TABLE 2
SUMMARY OF ALLOWED RATES OF RETURNS IN NEW RATE CASES, 1974 TO 1979

Year	Average Allowed Return on Equity	Average Allowed Return on Rate Base	Estimated Cost of Average Equity Capital for Electric Utilities
1974	13.50%	8.71%	12.22%
1975	13.22	9.00	13.28
1976	13.42	9.11	12.20
1977	13.12	9.25	NA
1978	13.87	9.62	NA
1979	13.32	9.75	NA

Sources: Allowed returns calculated from *Argus Utility Scope, Regulatory Service*, (New York: Argus Research Corporation, various dates); estimates from H. E. Thompson, "Estimating the Cost of Equity Capital for Electric Utilities: 1958–1976," *The Bell Journal of Economics* Summer, 1979. 10 (1979): 619-39.

Comparison of the actual returns of Table 1 with the allowed returns of Table 2 for the overlapping years of 1974 to 1976 indicates the significant difference between the two profit measures. Though the coverage of the two tables is not quite the same, the consistent excess of allowed over actual returns traces to two basic causes: the lag in utilities obtaining new rates and the failure of at least some of the new allowed return standards to be achieved in practice.

Next, comparison of the equity returns allowed each year with estimates of utilities' average equity costs indicates that allowable returns were probably exceeding the market's requirements, but not by much. There was little margin for a return specified in a rate case to deteriorate under actual experience if it was still to justify investors' expectations.

The entries in both tables support some general and important conclusions. State utility commissions have made substantial adjustments to counter the effects of inflation, yet these adjustments have not always been prompt or complete in their effects. Even if increased rates of return permitted utilities to raise capital, they did not secure the very favorable relationship between allowed returns and capital costs that prevailed for much of the 1950s and 1960s. Any positive incentive to overcapitalize, by virtue of Averch-Johnson effects, is far less plausible in the current climate of moderate (real) returns and substantial future uncertainty.

E. CAPITAL SPENDING INCENTIVES IN CONTEXT

The argument that there are positive incentives for overspending on fixed plant and equipment is thus far weaker today than it might once have been. However, efficient choice and control of construction projects demand more than the mere absence of perverse financial motives. The general problems posed by cost-of-service regulation remain. Both penalties and rewards for unwise spending choices are very much diluted. With financial motivation weakened, the chances that other forces will determine plant-spending decisions increase.

Enhancing stockholders' financial position is, after all, only one aim of utility decision making. Several influences could push spending upward. Technical and engineering considerations set bounds on feasible choices and may exert a more active pressure. Certain types and scales of generation facilities could, for instance, be preferred because they appeal to engineers' desire for innovation or challenge. The importance of the engineering profession in the management of utilities might enhance such technical goals over financial aims. The eagerness for growth as an end in itself, or because it serves managers' personal financial goals, could also bias spending decisions. Similarly, the inertia of past trends in demand growth may continue to guide utility managers after a break in these trends should have been apparent; and, even if Averch-Johnson formulas are no longer valid guides to contemporary investment choices, they could still be exerting an influence on these choices. If tilting toward fixed plant was once the common tendency of utility planners, this tendency might yet, to some degree, be embedded in the institutions and habits that govern current decisions.

A number of trends in both markets and regulation run counter to these forces. Profitability on new investment has, after all, declined and energy demand growth markedly slowed. Regulators have begun to scrutinize all elements of rate base determination more closely. For a company planning new generation plant in recent years, the possibilities that a portion of the plant's cost will be disallowed, or the whole not permitted to earn a satisfactory return, have been real.

Therefore, utilities are subject to a variety of forces, uncertain in their overall effects, changing over time, and differing among regulatory jurisdictions. Cost-of-service regulation remains an imperfect way of encouraging input efficiency. The results of past plant-spending decisions would merit scrutiny in any case. The necessity for scrutiny grows more acute when the record is one of continually inflating costs. The succeeding chapters of this report examine this record and some of its implications for regulators.

Chapter Two

TRENDS IN ELECTRIC UTILITY PLANT COSTS

A. INTRODUCTION

The imperfections of cost-of-service regulation have long vexed regulatory policymakers. In the last decade they have acquired a special importance. Increasing electricity bills have focused attention on all elements of utilities' costs of service. Though fuel outlays explain much of the increase, the surging costs of generating facilities have also played an important part. Increased plant costs will, moreover, be with us for a while. Embedded in the rate base, this aspect of inflation will continue to influence utility charges well into the future.

A cost overrun is the excess of the actual cost of a project over its announced or planned costs. Plant investment far above earlier estimates raises the possibility that earlier estimates were less than candid or that construction performance was inefficient. The steady upward trend in the actual costs of plants built over succeeding years is related to this overrun problem. This trend signals steadily increasing revenue needs for utilities and affects many ratemaking issues.

The problems of accurate cost estimation are severe enough in their own right. For a large, complex project, estimators attempt to guess correctly the types and amount of equipment and labor needed for construction of a facility whose design may not be completely specified at the time. The pace at which construction will proceed is even less certain.

Inflation complicates the problems of cost estimation by boosting costs of labor and material and increasing interest rates. Predictably smooth rates of inflation can be incorporated in cost projections; erratic movements in general price levels, or in construction cost series, cannot. Interest rates are even less susceptible to forecast. These rates move cyclically, pressed by both inflationary expectations and the efforts of federal monetary authorities to slow inflation by controlling credit.

A third element of cost overruns is of more direct concern to regulators. When costs are unpredictable, contracts between utilities and construction companies are written loosely, often on a cost-plus basis. Incentives for efficient contractor performance are thereby diluted. If the incentives for utilities to minimize costs are also weak, imprudent or unnecessary cost incurrence is likely.

This chapter attempts to sort out these aspects of plant cost increases with respect to three types of utility construction: nuclear and coal-fired generation plants, and transmission-distribution facilities.

B. GENERAL PROBLEMS OF COST ESTIMATION

Even without inflation cost estimation can be tricky. A good way of seeing why is to look at how estimates are made at various planning stages. Cost estimates prepared by utilities are similar to projections prepared by different organizations for a variety of purposes. A recent RAND study found that most estimates can be classified into one of five types.[1] They are, in order of ascending accuracy:

- initial estimates;
- preliminary estimates;
- budget estimates;
- definitive estimates; and
- actual, rather than estimated, outlays.

According to the RAND report, in planning for a major industrial process facility, the initial cost estimate is only an order of magnitude approximation of project costs; it is made before a project is well defined, and its primary purpose is to set research and planning priorities, not to determine major capital commitments. Initial cost estimates are intended to be within about 40 percent, plus or minus, of actual outlays.

[1] E. W. Merros, S. W. Chappel, and C. Worthing, *A Review of Cost Estimation in New Technologies: Implications for Energy Process Plants*, RAND Corporation, R-2481-DOE, July 1979, pp. 61-70.

After a project is better defined (scale, location, type of process, and so forth), industrial planners make a preliminary cost estimate. Preliminary estimates reflect standard scaling relationships and material/labor ratios; they are supposed to come within about 20 to 25 percent of actual outlays. These preliminary estimates are usually the basis for the decision to commit major engineering resources to the project, and thus, generally, to commit to the project itself.

After engineers have completed from 30 to 70 percent of the design work on a project, a budget estimate is made. Budget estimates are based on detailed specification of the physical ingredients that will go into a plant; a site has also been selected and, often, site preparation already begun. Budget estimates do not influence major decisions on the project itself. Rather, they are intended to inform management of what funds will be necessary, and when, to carry out the commitment. These estimates are expected to be within 10 to 15 percent of final outlays.

Most estimates of plant costs announced by electric utilities should be at least preliminary in nature and probably closer to budget estimates in their quality. Much of the site specification and design work necessary for budget estimates is, after all, also required for permits and licenses for power plants.

Finally, according to RAND, the definitive estimate is made after engineering and design work are from 90 to 100 percent complete and vendor quotes received on major pieces of equipment and jobs. This estimate is supposed to be within about 5 percent of actual outlays.

Industrial planners are accustomed to dealing with uncertainty about project costs and have found ways of incorporating it into decision processes. The accuracy of an estimate is affected by the specificity of project plans at the time it is made. Major decisions must be reached before plans are complete simply because detailed planning itself represents a significant resource commitment. Early estimates, while necessarily uncertain, are intended to be unbiased. The last point is a critical implication of uncertainty and the necessity for decisions. Companies can live with the commitment of major funds on the basis of imperfect information only if (on average at least) they guess right.

Factors Affecting Estimation Accuracy

The RAND authors looked at the record for three types of projects to identify both the causes and magnitudes of misestimates.[2] The projects reviewed included acquisition of major weapons systems, public works projects, and energy process projects. Almost all the projects reviewed were constructed by or for public agencies, or by regulated industries.

The most common sources of error are divided into two sorts: those that influenced the estimating of project costs, and those that affected the construction of the project itself.

The reliability of the estimate was influenced chiefly by how well the project was defined. When projects are ill-defined, scaling rules and ratios must be used, often yielding imperfect guides to actual costs. Some cost components were especially difficult to capture by such broad relationships: pipes, valves, and instrumentation, along with field fabrication work. More fundamentally, when planners contemplate using new techniques, or old ones at significantly larger scales, rules of thumb seem likely to go wrong. The purpose of the estimate also influenced its reliability. Where an estimate was a bid on a cost-plus defense contract, submitted bids were, in several instances, from 20 to 50 percent below the bidder's own best internal estimate of costs.

Four factors exerted the most influence on actual costs. First, externally imposed "scope" changes often altered the nature of the project. To the extent that these changes brought improvements or enlargements in the project, extra value was added along with higher costs. The RAND authors note, however, that repeated design changes often reflect uncertain purposes and management deficiencies. As we will see later, both of these effects are probably important in power plant construction. Second, deviations from an "appropriate" construction schedule also boosted costs. Such deviations either can be inefficient delays or overly compressed schedules that prompt lack of coordination and waste. A third cause was management and organization deficiencies. Though less quantifiable, this problem was thought to be important in cases where management responsibility was fragmented or unclear. Fourth, of course, outside factors such as regulation and unanticipated inflation played a prominent role in the overruns experienced.

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[2] Ibid., pp. 86–90.

Estimation Record

Table 3 summarizes the magnitudes of estimating errors examined in the RAND report. The first column shows the average ratio of actual project costs to first available estimates for each set of items. In most cases, the first available estimate is an initial or preliminary one, before design work begins, and the actual cost is the completed cost of the facility. The ratio has been adjusted, however, to remove the effects of general inflation and scope changes where possible. The last column shows the standard deviation in individual ratios (between actual and estimate) in each category. The table thus portrays any persistent errors in estimation (or bias) and its accuracy.

TABLE 3
SUMMARY OF COST-ESTIMATING EXPERIENCE
(Adjusted for General Inflation)

Items Estimated	Mean of Actual to Estimated Costs	Number of Items	Standard Deviation
Weapons, 1950s	1.89	55	1.36
Weapons, 1960s	1.40	25	.39
Public works:			
Highway	1.26	49	.63
Water projects	1.39	49	.70
Building	1.63	59	.83
Ad hoc	2.14	15	1.36
Major construction	2.18	12	1.59
Energy process plants	2.53	10	.51

Source: E. W. Merrow, S. W. Chappel, and C. Worthing, *A Review of Cost Estimation in New Technologies: Implications for Energy Process Plants*, RAND Corporation, R-2481-DOE, July 1979.

Compared with the estimating goals noted above, the record is a poor one. Even adjusted for inflation, a consistent tendency to underestimate is apparent. Moreover, the accuracy of individual project estimates, as measured by their standard deviation, is less than that expected of initial estimates by industrial planners, except barely, in the case of 1960s weapon's procurement.

The most consistent bias toward underestimation occurs for a project that is novel or one of a kind, at least for the organization constructing it. "Major construction" projects included the Alaskan oil pipeline, such public ventures as San Francisco's BART system, and several nuclear power plants. Before adjusting for unanticipated inflation and scope changes, the actual to estimate ratio was almost four to one. Even after adjustment, these projects cost more than twice what was expected. In each case the project, while perhaps not technically innovative, was distinctive in type, scale, or novelty to the responsible organization. Most of the first estimates for these major construction projects were also released publicly and used to advertise the project's feasibility or economic attractiveness. In the case of the pipeline, this advertisement was directed chiefly toward lenders and federal legislators. In the case of BART and other local projects, it was directed at local authorities and voters.

The cost record for "energy process" plants and for "ad hoc" public works projects is similar and may be similarly biased. The energy plants are primarily synthetic fuels facilities whose designs were poorly specified at first. The "ad hoc" category includes such works as the Albany Mall. Though not innovative, these were one of a kind: the constructing agency had little experience with this type of construction, and in its first published cost forecasts, perhaps little reason to be precise.

More modest ratios for other categories point up some significant contrasts. Weapons' acquisition programs often involve ambitious design goals and frequent changes in scope. These factors render cost estimation difficult for each individual system; however, the purchaser eventually acquires experience in assessing overrun trends and can adjust "naive" estimates for consistent tendencies. Interestingly, the accuracy of weapons' costing improved in the 1960s, hardly a period when the basic problems of estimation had evaporated.

The ratios for highway and water projects hint at similar possibilities. These are large-scale public works of types that are constructed repeatedly by the responsible agencies. The averages shown in Table 3 are better than for most other categories and obscure an improving trend. Researchers have found that these agencies have improved continually in their ability to forecast costs.[3] The Corps of Engineers, which was overrunning its initial estimates by more than two to one before 1952, was near an average ratio of 1.0 in the 1954–65 period. Similarly, the Bureau of Reclamation that had an average actual to estimate ratio of 2.77 before 1955 was at 1.09 in later years. In both cases, the improvements did not spring from increases in the accuracy of individual project estimates, but from adjusting for overall biases so that average results were more realistic. This ability to adjust for biases on the basis of past experience is an important aid to cost estimation.

Implications

Overall, the RAND results support several important conclusions about major project cost estimation. Estimation errors can be huge and only partly explainable by general inflation. Changes in project scope and design exert powerful effects on project costs but so can a failure to specify designs fully before estimating costs. Given these problems, inaccuracy in individual project estimates is likely to be large, but consistent biases should still be avoided. In examining initial cost estimates, it can also be important to consider the purposes for which they are offered. Estimates that promote projects can be poor bases for forecasting their real prospects.

These conclusions form the basis for inspecting actual trends in utilities' capital costs. First, however, we will look briefly at a problem that poses major difficulties at a project's start, though it can be adjusted for in retrospect: inflation.

C. INFLATION

Inflation is the chief cause of changes in most capital costs over time, and to the extent it is not anticipated, lies at the heart of many estimation problems.

Inflation is a generalized trend of increasing prices. This generalized trend becomes a component of the price changes for specific goods or services. When a specific price diverges from the general trend, "relative" prices change.

Inflation is rooted in economywide tendencies, such as excess demand or the momentum of inflationary expectations. Relative price changes can reflect differing lags in the propagation (or slowing) of inflation among different markets, or relative prices may shift because the basic balance of supply and demand is changing in a particular market.

Inflationary expectations also embed themselves in interest rates and in the returns sought for investment. At the same time, loosening or tightening of federal credit policies influences interest rates, especially for short-term debt.

The well-publicized acceleration in U.S. inflation is summarized in the first two columns of Table 4. Changes in the GNP deflator weight movements in the prices of goods and services by their importance in the gross national product; the Consumer Price Index (CPI) weights them by wage earners' budgets.

Inflation first accelerated with the deficits of the late 1960s. It had barely been dampened when food and oil price explosions reignited it in the mid-1970s. Double-digit rates were neared in annual changes in the GNP index and twice exceeded by the CPI. Though differing in year-to-year detail, both series show a similar pattern. Before the second surge, prices increased an average of about 4.5 percent per year. After 1973, the rate nearly doubled, to between 7 and 8 percent.

Thus, the past decade's inflation, while sharp, was hardly unheralded. It built up in rapid steps twice and is doing so again in 1979–80. A cost estimator using past trends to forecast the near-term future would have gone quite wrong twice during the period shown in the table. If made before 1968, a forecast of general inflation would probably have been low by about 3 percent per year; and, if the estimator was working just prior to 1973, he would likely have undershot actual events by at least a similar margin. Depending on the horizon over which the forecast was done, these errors could compound into substantial mistakes about future cost levels.

Construction Cost Increases

That, of course, was just the beginning of the potential trouble. As shown in the third column of Table 4, indices of construction costs moved at sharp variance with general prices. The Commerce Department's Construction Cost Index, which covers many types of buildings and locations, rose nearly half again as fast as economywide inflation, both before and after 1973. Especially sharp accelerations registered in 1974 and 1978.

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[3] Ibid., pp. 29–32.

TABLE 4
MEASURES OF GENERAL AND RELATIVE INFLATION: 1965 TO 1979
(Percentage Changes at Annual Rates)

Year	GNP Implicit Price Deflator	Consumer Price Index	Commerce Construction Cost Index	H-W All Steam, North Atl.
1966	3.3	2.9	3.9	3.0
1967	2.9	2.9	3.7	3.6
1968	4.5	4.2	5.1	4.0
1969	5.0	5.4	8.7	3.3
1970	5.4	5.9	7.1	8.0
1971	5.1	4.3	7.0	6.9
1972	4.1	3.3	5.5	11.5
1973	5.8	6.2	8.7	3.3
1974	9.7	11.0	16.7	10.8
1975	9.6	9.1	9.8	23.6
1976	5.2	5.8	4.2	7.6
1977	6.0	6.5	7.6	4.9
1978	7.3	7.7	13.1	6.2
1979	8.8	11.3	12.5	NA
Avg. 1966-73	4.5	4.4	6.2	5.4
Avg. 1974-78	7.5	8.0	10.2	10.4

Sources: *Economic Report of the President* (Washington: U.S. Government Printing Office, January 1980); "Quarterly Cost Roundup," *Engineering News-Record*, various dates; and *Trends of Public Utility Construction Costs*, Bulletin no. 107, May 1978, Whitman, Recquardt and Associates, Table E-1.

The fourth column shows an index of what actually goes into a power plant, the Handy-Whitman index of costs of constructing steam electric plants in the North Atlantic states. Though the H-W index often increased at a different yearly pace, its cumulative rise was close to that of the broader Commerce Department series. In both the earlier and later periods, the rates were appreciably faster than general price movements.

The increase in utilities' input costs was similar to that of other construction, and as shown in Table 5, was spread widely throughout the country. (The term "input costs" emphasizes that the index measures movements in the cost of specific ingredients to plant construction, not the costs of completing an actual plant.) According to the table, average rates of increase up to 1973 were virtually identical among the six regions. After 1973, rates were modestly higher in the South and West. Differences were hardly large, though, with the biggest gap between North Atlantic and Pacific states of only 1.6 percent per year. More rapid increases in the South and West may reflect these regions' resilience during the 1974-75 recession. With business not as damaged by the recession, and indeed, some resource extraction business undoubtedly spurred, construction activity was less subject to downward price pressures.

TABLE 5
VARIATION IN UTILITIES' CONSTRUCTION INPUT COST INCREASES BY REGION
(Average Percentage Changes at Annual Rates)

Period	North Atlantic	South Atlantic	North Central	South Central	Plateau	Pacific
1966 to 1973	5.4	5.4	5.3	5.1	5.0	5.0
1974 to 1978	10.4	10.9	10.6	11.5	11.7	12.0

Source: *Trends of Public Utility Construction Costs*, Tables E-1 through E-6.

Inflation in utility construction costs varied somewhat more by type of plant. Table 6 shows rates of cost increase for various types of production (generation) plant as well as transmission and distribution plant for two periods and regions. All indices are of installed costs and include labor, equipment, and material. Rates of increase were fairly similar before 1974. Hydropower costs went up more rapidly than other plant costs in the North Atlantic but do not amount to much actual outlays. Other cost series moved in close alignment. From 1974 on, the pattern disperses, but not dramatically. Nuclear and hydropower plant costs increase more sluggishly, and nongeneration plant move up more rapidly. This pattern characterizes the faster moving Pacific index as well as the North Atlantic one.

TABLE 6
VARIATION IN UTILITIES', CONSTRUCTION INPUT COST INCREASES, BY TYPE OF PLANT

1966 to 1973:	North Atlantic	Pacific
Fossil Production Plant	5.3%	4.8%
Nuclear Production Plant	5.7	5.5
Hydroproduction Plant	6.2	5.5
Transmission Plant	5.3	5.4
Distribution Plant	5.6	5.2
1974 to 1978:		
Fossil Production Plant	10.5	11.4
Nuclear Production Plant	8.7	9.5
Hydroproduction Plant	8.8	10.1
Transmission Plant	10.8	12.7
Distribution Plant	10.2	12.0

Source: *Trends in Public Utility Construction Costs*, Tables E-1 and E-6.

Increases in the cost of construction "inputs" were thus broadly similar for utilities and other sectors, and within utilities, by plant type and region. Similar market trends were clearly at work. Before 1974, labor costs partly explain this common trend. According to Table 7, wages for most types of skilled and nonskilled construction labor were increasing at rates significantly above both general price trends and the pace of construction cost before 1974. Even in Pacific states, wage rates were moving slightly ahead of inflation. Wages moving faster than prices is, of course, a characteristic of an economy that is generating enough in productivity gains to raise workers' living standards. After 1974, that changed. Many of the same factors that made it difficult for wage earners to maintain real living standards also rendered labor costs a less important explanation of increasing construction costs. According to the bottom portion of Table 7, labor costs in the North Atlantic rose much less rapidly than overall construction costs. In the Pacific, wages went up at a slightly slower pace than that region's construction index.

TABLE 7
VARIATION IN UTILITIES' LABOR COST INCREASES, BY MAJOR TYPE
(Percentage Changes at Annual Rates)

1966 to 1973	North Atlantic	Pacific
Building Trades Labor	8.0	6.9
Common Labor	8.6	6.6
Electricians	7.5	7.4
Pipefitters	9.1	6.9
1974 to 1978		
Building Trades Labor	6.3	9.5
Common Labor	7.0	10.1
Electricians	7.1	11.1
Pipefitters	6.6	9.4

Source: *Trends in Public Utility Construction Costs*, Tables B-1 and B-6

The economic dislocation of the 1974-78 period was largely responsible for the specialized inflation in utilities' plant costs. Fuel plays an important part in both on-site fabrication and in the production of many construction materials. The costs of steel bars and brick both rose at average annual rates of almost 11 percent from 1974 to 1978. Among equipment types that showed rapid increases, according to Handy-Whitman data, was coal-fired boiler equipment that went up at about 11.5 percent per year over the same period.

Interest Rates

A further effect of the postembargo turmoil has been a high-interest rate environment. Financing charges are a final "input" to the installed cost of a generation plant. Increased interest charges add to the valuation of a plant in the rate base. The portion of interest that represents inflation is another reminder that there is a delay between spending for and getting an installed project, and that during that delay, the money price of everything, including the project's output, is increasing. The remainder of the interest charge is the "real" cost of delay.

The distinction between the inflation and real components of interest rates is analogous to the prior distinction between general inflation and relative price shifts. Trends in general inflation can surprise cost estimators by pushing all finance charges up. Changes in the relative price of capital, reflecting capital market changes, further complicate forecasting.

Table 8 repeats the GNP deflator's summary of inflation and shows trends in several types of interest rates. The second and third columns present yields on bonds of two classes, AAA and BAA. Most long-term utility borrowing would normally be made within the range established by these rates. The third column shows movements in the rate for short-term prime borrowing, a market highly sensitive to credit pressures but not a usual source for financing capital projects.

TABLE 8
INFLATION AND INTEREST RATES, 1966 TO 1979

		Average Interest or Yield			
Year	Percentage Increase in GNP Deflator	AAA Bonds	BAA Bonds	Prime Interest Rate	$\left[\frac{AAA + BAA}{2}\right]$ – GNP Deflator, Inc.
1966	3.3	5.13	5.67	5.63	2.10
1967	2.9	5.51	6.23	5.61	2.97
1968	4.5	6.18	6.94	6.30	2.06
1969	5.0	7.03	7.81	7.96	2.42
1970	5.4	8.04	9.11	7.91	3.18
1971	5.1	7.39	8.56	5.72	2.87
1972	4.1	7.21	8.16	5.25	3.59
1973	5.8	7.44	8.24	8.03	2.04
1974	9.7	8.57	9.50	10.81	(0.67)
1975	9.6	8.83	10.61	7.86	0.12
1976	5.2	8.43	9.75	6.84	3.89
1977	6.0	8.02	8.97	6.83	2.50
1978	7.3	8.73	9.49	9.06	1.81
1979	8.8	9.63	10.69	12.67	1.36
Average 1966–73	4.5	6.74	7.59		2.65
Average 1974–78	7.6	8.52	9.66		1.53

Source: *Economic Report of the President* (Washington: U.S. Government Printing Office, 1980).

The time pattern of interest movements is broadly similar to that of inflation but shows a more muted break between the earlier period, 1966-73, and the 1974-78 span. Long-term yields rose but not as much as inflation.

There are probably several reasons for this. Interest rates anticipate inflation and may show an early reaction to well-perceived price movements. More fundamentally, even long-term rates are sensitive to short-term market conditions. The years after the oil embargo included a deep recession and much idle industrial capacity. The diminished need for borrowing lowered prime rates from 1975 to 1977 and dampened charges for long-term borrowing.

Weak loan demand thus decreased the real cost of financing during the 1974 to 1978 period. Table 8's final column indicates trends in the relative price of borrowing by presenting a simple average of AAA and BAA bond yields, less the inflation rate. Real borrowing costs were subject to wide swings after 1973 but were generally lower than in the earlier period.

At first glance, the entries in Table 8 appear to present fewer problems than those of forecasting non-financial input costs. Movements in long-term rates were more gradual, and relative price shifts favorably downward. There is an obvious qualification, though. Finance charges enter a plant's costs compounded over several years. Guessing wrong by 2 percent in a project that stretches over three years of actual construction can put total financing estimates off by 4 to 5 percent. Larger misses or longer projects create even bigger errors.

Implications

In summary, the effects of inflation on plant costs can be looked at in two ways, as pushing up these costs over time and as considerably complicating the task of forecasting cost increases. The rapid rates of increse in construction costs experienced over the last 15 years, account for substantial increases in plant costs. Further, the "breaks" in inflation trends could prompt large underestimation errors.

Interest rates are another less easily summarized aspect of inflation's impact. The influence of interest rates on project costs and estimation errors is likely to be large and very sensitive to the timing of construction and finance commitments.

A Note on Efficiency and Scale

Trends in the costs of "inputs" to electricity generation affect consumers only indirectly. Increases in utilities' costs can be offset, wholly or in part, by improvements in the efficiency of building power facilities or in the productivity of these facilities in generating electricity.

Over most of its history, of course, the electric utility industry did just this. In a process that paralleled economywide efficiency gains, but to a much more successful degree, the nominal cost of electricity was brought steadily downward, and the price of electricity relative to other prices continued to go down until 1974.

An important reason for these reductions in costs were opportunities for economies of scale at several points in the production and delivery of electricity. Scale economies arise at the plant level, as up to some size, increased capacity lowers the average cost of generating power. Scale economies are also important in the transmission of electric power, where capacity increases with the square of a line's voltage, but costs go up in a roughly linear fashion.[4] Finally, there are important economies of scale related to a utility system as a whole: larger, well-coordinated power grids bring the chance to improve both reliability and capacity utilization rates. As one recent study argued, differences in utilization may be the most important source of scale economies in modern power systems.[5]

All scale economies are important determinants of consumers' electricity bills. In this report, however, we are examining costs at the plant level. Therefore, we are concerned only with scale economies at that level, and then, chiefly as a means of adjusting for differences in plant size. It bears remembering that there is another set of influences at work between these plant level costs and the consumers who must ultimately pay for them.

With this limitation noted, we now turn to trends in plant costs and the reasons for their frequent underestimation.

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[4] L. W. Weiss, "Antitrust in the Electric Power Industry," in *Promoting Competition In Regulated Markets*, ed. A. Phillips (Washington: The Brookings Institution, 1975).

[5] J. F. Stewart, "Plant Size, Plant Factor and the Shape of the Average Cost Function," *The Bell Journal of Economics* 10 (1979): 549–65.

D. NUCLEAR PLANT COSTS

The most arresting instances of cost underestimation have occurred in nuclear power plant construction. This sector presents, in extreme form, all of the problems that cost overruns pose for consumers and regulators alike.

Commercial nuclear power began in the late 1950s and early 1960s with the operation of several small reactors at or below 200 megawatt (MW) capacity. Subsidized by the federal government, these reactors were not expected to compete with efficiently scaled fossil fuel plants. In the mid-1960s, much larger plants were ordered under "turnkey" contracts between utilities and major construction companies, such as Westinghouse and General Electric. Turnkey contracts were agreements by the vendor to complete plants at fixed prices. Vendors, though they might be willing to sustain limited losses to promote future business, were not anticipating major overrun problems.

Soon afterwards, new orders for reactors up to and above the 1,000 MW size class began to be placed under cost-plus contracts. Under these agreements, frequent changes in design could be incorporated without renegotiation of basic contract terms. Such changes became increasingly frequent with time and intensified federal regulation of nuclear power.

The Overrun Record

Table 9 presents selected nuclear cost overruns representing about one-third of current installations. Most of the entries are taken from a book published by the Environmental Action Foundation (EAF), a group highly critical of nuclear power. However, other entries taken from a variety of available sources support and strengthen the general direction of EAF's data.

Overruns in nuclear plant construction have varied, but only from the very substantial to the gigantic. The original estimates are generally those given by the utility in announcing its plans or seeking permit approval. The actual figures are the plant's final costs, or where construction is incomplete, the latest estimate.

Even the lowest actual/estimate ratios, those in the 1.58 to 2.00 range, evidence considerably more error than is usually tolerated in industrial cost estimating. Fully two-thirds of the selected nuclear plants were subject to overruns that left final costs more than double estimated outlays. In most of these cases, the overrun experience was worse than that experienced in the one-of-a-kind public works projects noted earlier. In four cases, final costs were more than triple initial estimates. The average for all overrun ratios shown in the table up through 1975 was about 2.2.

Comparability of the entries in Table 9 is complicated by differing time periods, plant types and sizes, and estimating methods. However, it is plain that errors in estimating nuclear costs, in addition to being larger than errors for more conventional construction projects, have also not been reduced by time and experience. A Mitre Corporation study found that the actual-to-estimate ratio increased steadily over time for plants completed in 1971 through 1975.[6] In addition, it is apparent from Table 9 that some of the worst overruns occurred on plants that have only recently been completed or are still under way. These worst cases, with overrun ratios of 3.8 to more than 5.0, include the Salem, Midland, Davis-Besse, and Shoreham nuclear plants. These later plants should have benefited the most from increased experience with nuclear construction.

Effects of Inflation

One factor that frustrates improvements in estimation accuracy is unanticipated inflation. The effects of unanticipated inflation on overruns cannot be determined precisely, since the inflation assumptions of initial estimates are not usually available. However, we can put some limits on the possible size of these effects by making some reasonable inferences from the inflation trends previously reviewed.
reasonable inferences from the inflation trends previously reviewed.

Table 10 presents illustrative actual-to-estimate ratios that could have occurred in nuclear power plants if specified degrees of unanticipated inflation were the sole problem. The headings on the columns are the assumed "mistake" about inflation. For instance, the first column assumes that cost estimators expected 3 percent inflation per year in construction costs and the actual trend was 5 percent. According to the Handy-Whitman steam electric construction cost series, this was about the

[6] C. Blake, D. Cox, W. Fraize, *Analysis of Projected vs. Actual Costs for Nuclear and Coal-Fired Plants*, (Fairfax, Va.: The Mitre Corporation, 1976).

TABLE 9
SELECTED CAPITAL COST OVERRUNS IN NUCLEAR POWER PLANTS

Company	Plant	Year Completed	Original Estimate (Millions of Current Dollars)	Actual or Latest Estimated Cost (Millions of Current Dollars)	Actual to Estimate Ratio
Baltimore Gas & Electric[a]	Calvert Cliffs	1975	$272	$ 429	1.58
Boston Edison[a]	Pilgrim 1	1972	65	239	3.67
Carolina Power & Light[a]	Brunswick 2	1975	200	382	1.91
Consumers Power[a]	Palisades	1971	93	188	2.02
Dairyland Power Cooperative[a]	LaCrosse	1962	11	20.7	1.88
Duke Power[a]	Oconee 1, 2, 3	1973–74	341	574	1.68
Florida Power & Light[a]	Turkey Point 3 & 4	1972–73	100	244	2.44
Georgia Power[a]	Hatch 1	1975	111	276	2.49
Indiana & Michigan Electric[a]	Cook 1	1975	300	539	1.80
Metropolitan Edison[a]	Three Mile Island 1	1974	110	200	1.82
Nebraska Public Power District[a]	Cooper	1974	101	246	2.44
Northeast Utilities[a]	Millstone Point 2	1975	186	418	2.25
Northern States Power[a]	Prairie Island 1 & 2	1974	200	410	2.05
Omaha Public Power District[a]	Ft. Calhoun 1	1966	64	178	2.78
Portland General Electric[a]	Trojan	1975	235	465	1.98
Tennessee Valley Authority[a]	Browns Ferry 1 & 2	1974–75	247	513	2.08
Vermont Yankee Nuclear Power[a]	Vermont Yankee	1972	80	220	2.75
Public Service Company of Colorado[b]	Ft. Vrain	Tested in 1977	89	1,200	NM
Philadelphia Electric Co.[b] and Public Service Electric and Gas of New Jersey	Salem 1 & 2	1 in 1977	315	1,200	3.81
Consumers Power Company[b]	Midland	⅓ completed in 1979	256	1,300	5.08
Philadelphia Electric Co.[c]	Peach Bottom 2	1973	138	377	2.73
Philadelphia Electric Co.[c]	Peach Bottom 3	1974	125	377	3.01
Georgia Power[c]	Hatch 2	⅓ completed in 1979	189	513	2.71
Consolidated Edison[c]	Indian Point 2	1973	134	212	1.58
Consolidated Edison[c]	Indian Point 3	1976	159	570	3.58
Toledo Edison[d]	Davis-Besse	1977	136	650	4.77
Tennessee Valley Authority[c]	Sequoyah 1 & 2	65% complete in 1977	336	674	2.01
Long Island Lighting[d]	Shoreham	Expected in 1980	261	1,188	4.55

Sources: [a] R. Morgan, *Nuclear Power, the Bargain We Can't Afford* Washington: Environmental Action Foundation, 1977).
[b] News clippings.
[c] C. Blake, D. Cox, W. Fraize, *Analysis of Projected Versus Actual Costs for Nuclear and Coal-Fired Nuclear Plants* (Fairfax Va.: The Mitre Corporation, 1976).
[d] See Tables 12, 13, and 14 in succeeding text; the Shoreham ratio is based on a 1977 final cost estimate that may be substantially exceeded.

change in average inflation rates from the early 1960s to the 1966–73 period. An estimator making simple extrapolations from the earlier to later period would have erred by about 2 percent per year. In equivalent fashion, the last column depicts the error that would have resulted from using 1966–73 average experience to forecast 1974–78 trends.

The worst effects of inflation on overruns occur when a large mistake is compounded over long estimate-to-construction periods. Periods up to 7 years were increasingly prevalent for later projects. Shorter periods and smaller errors obviously yield more modest problems.

According to entries in Table 9, the average overrun ratio for plants completed before 1976 was about 2.2. Under any but the worst assumptions, less than half of this could have been accounted for by unanticipated inflation. Further, the worst assumptions about inflation (from 5 percent to 10 percent, 11 years) are generally realistic only in a later period when the overruns actually experienced were much worse than the most pessimistic entry in Table 10.

Though necessarily imprecise, this illustrative comparison underscores the limited role played by inflation in cost overruns. To understand other causes, we must examine the trends in actual plant construction costs over time.

TABLE 10
ILLUSTRATIVE ESTIMATES OF THE EFFECTS OF UNANTICIPATED INFLATION

Estimated to Actual Inflation:	3% to 5%	3% to 7%	5% to 10%
Period between Estimate and Actual	Overrun Due to Unanticipated Inflation		
7 years	1.14	1.31	1.38
9 years	1.19	1.41	1.52
11 years	1.25	1.52	1.67

Trends in Plant Costs

Table 11 shows nominal plant costs per kilowatt of design capacity for nuclear plants, organized by year of first operation. For each year, the high-, low-, and average-plant costs are shown. All costs are in "mixed current dollars," that is, dollars actually expended over the plant's multiyear construction period. Though costs moved erratically on occasion, the overall trend was clearly upward. According to the average-plant-cost column, per kilowatt costs were increasing by an average of about 18 percent per year, or $54 per kilowatt, unadjusted for inflation.

TABLE 11
INCREASES IN PLANT COSTS, 1970 TO 1977

Year	Number of Plants	Lowest Plant Cost (Mixed $/kW)	Average Plant Cost (Mixed $/kW)	Highest Plant Cost (Mixed $/kW)
1970	2	162	$171	179
1971	5	118	164	219
1972	6	130	246	360
1973	9	138	217	298
1975	9	288	457	541
1976	4	400	554	695
1977	9	288	555	865

Source: C. Basset, "The High Cost of Nuclear Power Plants," *Public Utilities Fortnightly*, April 27, 1978.

Removing the effects of inflation from plant costs is difficult because of their expression in mixed dollars. Furthermore, the dispersion of individual plant costs means that trend estimation is highly sensitive to the plant data included. Nevertheless, a number of studies have demonstrated that nuclear plant costs are rising much more rapidly than general inflation or increases in the costs of inputs to their construction.

In a 1974 study of nuclear cost trends, Irwin Bupp estimated that adjusted for general inflation, plant costs were going up by about $23-$32/kW per year.[7] Bupp had to use preliminary cost information on many plants not yet in operation. Later analyses have found sharper increases. In 1978, a RAND study by William Mooz found that after other cost influences had been taken into account, constant dollar plant costs were rising by $140/kW for every year that passed before permit issuance.[8] Recently, in an analysis that explained 92 percent of the variation in nuclear costs, Charles Komanoff found an average escalation of 13.5 percent per year for plants that went into operation in 1971 through 1978.[9]

Both Mooz and Komanoff used the Handy-Whitman index of steam electric plant costs to adjust for inflation, thus netting out the effects of rapid increases in construction costs. After inflation adjustment, these two studies proceeded to estimate the effects on plant costs of both individual plant characteristics, and indirectly, general factors affecting all plants.

Plant Characteristics Affecting Costs

The plant characteristics upon whose significance both studies broadly agree include scale economies, the experience of the Architect-Engineer (A&E) involved, common unit construction, and cooling towers. Scale economies were significant up through the 1,150 MW range, enabling a 10 percent reduction in unit charges for every doubling in size, according to Komanoff. Location of two or more units at the same site saved 10 percent in capital costs. The studies showed that each doubling of A&E experience, measured by number of plants it had previously constructed, saved between 7 to 10 percent of costs. Mooz estimated that cooling towers added up to $90 million to plant costs on average, but this would vary quite a bit by plant.

Increasing Safety Requirements

Except for cooling towers, each of these plant characteristics has worked to reduce average capital costs over time. Nuclear plants have grown larger, taking advantage of scale economies. A&Es have acquired more experience; and with the expansion of nuclear power, more opportunities have arisen to save on site preparation and common support facilities by locating several plants in the same spot. Removing the effects of individual plant characteristics thus left an even larger increase in plant costs to explain. Both Mooz and Komanoff assigned these increases to the common trend affecting all power plants over this period: stricter federal safety regulation.

There is no good numerical index of the intensity of nuclear safety regulation. Mooz found that the date a plant's construction permit was issued has had the most significant statistical effect, and the intensity of regulation has undoubtedly increased over time. With each year adding $140 per kilowatt to project costs, the implied strengthening of regulation was boosting plant costs far more than scale improvement, A&E experience, or common unit location could possibly reduce them.

Komanoff agrees that regulation has been getting stricter with time but sees more fundamental forces at work. It is reasonable that society should place more stringent safeguards on reactors as more reactors are built (to limit the chances of an accident occurring somewhere). Moreover, if the regulatory process works essentially by responding to new problems as they surface in the planning or operation of new reactors (as Komanoff presents it, it does), then rules will proliferate as new reactors are built. Komanoff thus represents the driving force of regulation as the increase in nuclear generation itself. He estimates that each doubling of nuclear capacity boosted unit costs about 50 percent during the 1970s, through the tighter regulation it brought.

Changing Regulatory Environment[10]

To understand the strength of these regulatory effects on plant costs it is useful to review the history of federal safety regulation quickly. As practiced by both the old Atomic Energy Commission (AEC) and the present Nuclear Regulatory Commission (NRC), regulation has been increasingly tough in its substantive requirements and frustrating in its methods.

For plants coming into operation from 1971 through 1978, the period of most of the estimates previously cited, regulators have steadily toughened the design requirements for nuclear facilities. For instance, virtually all U.S. reactors have been required to meet increasingly stringent standards to pro-

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[7] I. C. Bupp, "The Economics of Nuclear Power," *Technology Review*, February 1975.
[8] W. E. Mooz, *Cost Analysis of Lightwater Reactor Power Plants* (Santa Monica Calif.: RAND Corporation, 1978).
[9] C. Komanoff, "Cost Escalation of Nuclear and Coal Power Plants" (New York: Komanoff Energy Associates, 1980).
[10] This discussion of nuclear safety requirements draws heavily from Komanoff, "Cost Escalation."

tect against earthquakes. Shock absorbers, pipe restraints, and equipment upgrading have been added. The portions of the unit that must be able to withstand seismic thrusts have been expanded beyond the reactor itself to include the control room, the Emergency Core Cooling System (ECCS), and other facilities. These changes boosted costs for both equipment installations and quality assurance measures. Similarly, costs were increased for some reactors by tougher standards for tornado and flood protection. Plant instrumentation, the reliability required of the ECCS, fire control systems, and the rerouting of pipe and wire lines to minimize chances of failure from a single cause, or "common mode", were also upgraded during the 1970s.

Methods of Applying Rules

More stringent standards often followed discovery of a potential problem at a particular plant. These standards were then applied to other plants either in design or construction phases. Changed standards were then codified in "regulatory guides" that gave acceptable solutions to safety problems; often the acceptable solutions were unavoidable, and the guides acquired the force of regulations.

The issuance of regulatory guides and later compilation of a Standard Review Plan, outlining NRC review procedures, were intended to lend some predictability to regulatory requirements. This intent was undercut, however, by the rapid changes in standards and the practice of applying the "highest common denominator" of design requirements at any given time to all plants. These two aspects of both AEC and NRC regulation meant that plants already well under way had to incorporate many new requirements for which they might be poorly designed. For instance, plants originally contoured to minimize use of steel and concrete were ill suited to the large increases in piping and wiring that followed tougher standards for backup systems.[11]

The overall significance of such inefficiencies is not known but is recognized to be large. In 1976, Michael Murray estimated that standardizing design and licensing requirements could cut (then) capital costs by ten percent;[12] and nuclear critic Charles Komanoff indicates that if the enhanced standards of the late 1970s had been known when the plants that had to meet them were first designed, nuclear cost growth could have been lessened substantially, perhaps by as much as 3 to 4 percent per year.[13]

Overall, the influence of changing regulation was to change the scope of nuclear construction projects continually. In addition to the inefficiences induced, such a situation would have two further effects. Estimators would never know exactly what was to be built, and they would develop no experience with which to adjust for their own errors.

Overruns in Major Plants

Indications of the importance of regulatory changes also come from analyses of specific nuclear plant overruns. Table 12 summarizes one such analysis performed on the Davis-Besse Unit of Toledo Edison by Christopher Bassett of the Public Utilities Commission of Ohio.[14] The Toledo Edison unit's overrun, of about 4.77, was large but not out of line with those of other plants reaching completion in the late 1970s. Unanticipated inflation, in the form of escalation clauses in contracts, boosted original project estimates by 63 percent but accounted for little over one-fifth of the total overrun. The 63 percent figure is consistent with our earlier worst estimate of what unanticipated inflation and long delays might have done to plant costs in the late 1970s.

By far the greatest share of the overrun was caused in some fashion by design changes mandated by the NRC. The author estimates that only about half, or $195 million of the nearly $400 million due to these changes, actually bought the modifications; the remainder was due to productivity losses for retrofitting and to increased interest during (delayed) construction.

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[11] Telephone conversation with Lou Perl, National Economic Research Associates, New York, May 30, 1980.

[12] R. M. Murray, Jr., "The Economics of Nuclear Power Generation—1975-2000," *The Nuclear Power Controversy*, ed. A. W. Murphy (Englewood Cliffs, N.J.: Prentice-Hall, 1976).

[13] Telephone conversation with Charles Komanoff, May 30, 1979. However, it is central to Komanoff's view of nuclear trends that design standards should not and cannot be frozen, since the standards are themselves reacting to the increased use of, and experience with, nuclear power.

[14] C. Bassett, "The High Cost of Nuclear Power Plants," *Public Utilities Fortnightly*, April 27, 1978.

TABLE 12
DAVIS-BESSE UNIT No. 1
ANALYSIS OF CONSTRUCTION COST INCREASES

Cost Component		Thousands of Current Dollars	Component as Percentage of Ultimate Costs of Project
Original Appropriation– 12/26/67		$136,000	21%
Unit Size Increase 800 MW to 906 MW		18,000	3%
Inflation in Labor and Materials		86,000	13%
Cooling Tower Addition		11,000	2%
Higher Land Cost for Restoration of Marshlands		1,000	1%
NRC Modifications and Their Chain Effects:			
Design modifications:	$195.000		
Loss of productivity due to retrofitting the above changes:	72,000		
Increase in AFUDC charges due to construction delays and cost increments for above changes:	110,000		
Greater cost for training and acceptance:	21,000		
		398,000	61%
Ultimate Costs of Total Project		$650,000	100%

Source: C. Bassett, "Cost of Nuclear Power Plants."

The importance of labor costs in overruns was emphasized by Bassett who noted increases in the 10 largest construction contracts at Davis-Besse. Of these, labor-intensive contracts went up the most rapidly by far. Architect & Engineering services rose nearly 500 percent and electrical work went up almost 800 percent. By contrast, contracts for equipment items rose moderately with the two largest, for the steam supply system and the turbine-generator, up by 18 and 8 percent.

Bassett's estimate that only half of the design-related cost increases at Davis-Besse actually bought improvements is necessarily judgmental, but the importance of labor-related costs is confirmed in other project studies. Table 13 summarizes cost elements from a Booz-Allen management audit of Long Island Lighting Company's Shoreham plant, projected (in late 1977) to cost nearly $1.2 billion.[15] This yields an overrun ratio of 4.55, quite close to the Davis-Besse ratio. Though Booz-Allen did not assign cost increases to design categories, their results appear otherwise consistent with those for Davis-Besse. Increased AFUDC accounted for 18 percent of the 1977 estimate, or about 23 percent of the overrun itself. The bill for A&E services was up by 1100 percent, even more than for the Ohio plant. Other labor accounts rose at nearly double the rate for material accounts.

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[15] Booz-Allen & Hamilton, Inc., "... study of Long Island Lighting Company's (LILCO's) major plant project management process ..." (an untitled, undated copy of this study was obtained from the New York Public Service Commission). Recent informal contacts have indicated that Shoreham's cost is likely to go much higher than the 1977 figure of $1.2 billion.

TABLE 13
SHOREHAM SUMMARY OF CONSTRUCTION COST INCREASES

	Thousands of Current Dollars	Component Increase as Percentage of 1977 Estimate	Percent Increase
1969 Project Estimate	$ 261,000	22%	Not Meaningful
Increase in A&E Services	160,000	13	1100%
Increase in Other Labor Accounts	343,000	29	376
Total Increase in AFUDC	208,000	18	520
Increase in Material and Other Accounts	216,000	18	189
1977 Project Estimate	$1,188,000	100	Not Meaningful

Source: See text.

Analysts did not assess the role inadequte management or contracting practices might have played in the overrun in either the Shoreham nor Davis-Besse cases. In an audit of the Salem 1 nuclear plant, an attempt to identify such effects was made. A Theodore Barry (TBA) project audit made both "hard" and "soft" estimates of how much might have been saved if acceptable management practices had been followed throughout. Table 14 presents these estimates.

The total overrun in the case of Salem was from $315 million to about $1,200 million, or nearly $900 million in current terms. Of this total, TBA judged that from $22 million to $70 million, or from 3 to 8 percent, might have been saved. The bulk of this total occurs, not unexpectedly, in work force utilization. Significant savings were also estimated as possible through improving overall management techniques (that is, information and control functions) and by avoiding unnecessarily wasteful rework. Very small savings were estimated as possible by economizing in nonlabor procurement.

TBA did not judge whether the improvements they identified could reasonably be expected amidst the novel and changing conditions under which Salem 1 was built. Pennsylvania ratemaking authorities basically accepted the TBA results and disallowed a portion of the plant's costs. The New Jersey commission accepted the utilities' argument that their methods were necessary and should not be second-guessed.

TABLE 14
AREAS OF IMPROVEMENT AND ESTIMATED COST SAVING IN SALEM 1

Area of Improvement	"Hard" Estimate of Potential Cost Savings ($ Millions)	"Soft" Estimate of Potential Cost Savings ($ Millions)
Project Management:		
Planning/Scheduling and Control	$ 0	$12
Rework	5	20
Work force Utilization	16	35
Materials Management	.8	1.7
Construction Equipment	0	1.6
Totals	$21.8	$70.3

Source: Telephone conversation with Perry Wheaton, Theodore Barry and Associates, July 7, 1980.

Significance of Types of Overrun Problems

Though rooted in common causes, various types of cost increases occur in different ways and have different implications. The increases in AFUDC accounts are really composed of two kinds of increase: higher interest rates to be paid because interest rates rose between the forecast and actual construction period; and the higher cumulative charge, in real terms, that comes from stretched-out construction schedules. As noted in the preceding section, most of the increase in interest rates is due to unanticipated inflation.[16] Though it boosts nominal outlays on the project, it does not represent an increased real burden on ratepayers. Moreover, this nominal increase is pretty much unavoidable. However, the second kind of AFUDC increase, higher real financing charges, does burden consumers because it represents a deferral of the benefits to be obtained from invested funds.

Average construction durations for nuclear projects have increased from slightly less than four years for plants completed in 1971, to about six years for plants finished in 1974, to almost eight years in 1978.[17] Using a real interest rate of 3.5 percent and reasonable assumptions about the timing of outlays during construction, we can estimate the effects of extended construction periods as shown in Table 15 below. According to the table, even stretching-out construction to eight years adds only about 10 percent to a project's real financing costs. Thus, while current outlays for AFUDC comprise a relatively large part of overruns, the actual and avoidable burdens imposed by them are fairly small. In the case of the Davis-Besse or Shoreham overruns, only about 3 percent of the overrun is an increase in real financing charges; the remainder, about 40 percent, reflects changes in nominal interest rates.[18]

TABLE 15
INFLUENCE OF EXTENDED CONSTRUCTION PERIODS ON REAL AFUDC*

Construction Period	Real Interest during Construction	Increase as Fraction of 4.6 Overrun
4 years	9%	NM
6 years	14%	.014
8 years	19%	.027

Assumes: 3.5% real interest rate; 15% of funds spent at beginning of construction, 50% by midpoint, 100% by end.

The causes of stretched-out construction schedules are varied but lean heavily toward the regulatory side. In a 1974 survey of 47 plants by the Atomic Industrial Forum, nearly half of the delays experienced were attributed to changes in regulatory requirements, while only about 21 percent were prompted by equipment delivery and labor productivity problems. This breakdown may, moreover, understate the impact of changing regulations: Where delays are expected to be frequent in any case, suppliers could become lax in servicing a nuclear facility.

Increased material costs are a significant element of overruns and the one most easy to associate with design changes. Many pieces of equipment and other supplies can be ordered under fixed price contracts, or ones subject to price index escalation. These contracts can be bid competitively and are not cost reimbursable. Opportunities for waste and mismanagement are inherently less for such contracts.

Very modest increases were registered for specific pieces of equipment in the case of Davis-Besse, and the increase in total material bills for Shoreham, especially adjusted for inflation, was considerably smaller than other increases. Generally, increased material bills go to purchase increased volumes of materials. According to one recent report, for instance, concrete and wire requirements per plant nearly doubled from the late 1960s through the late 1970s.[19] Some of this increase in materials used may have been unnecessary, but it is difficult to prove or quantify potential waste.

Increased labor costs are the most important and controversial element of cost overruns. There is ample evidence of low-labor productivity on nuclear sites, relative to normal construction standards, but disagreement about its causes. The influence of federal safety regulation is pervasive, but other factors also intrude.

[16] See p. 23, above.

[17] Basset, "Cost of Nuclear Power Plants."

[18] This is consistent with findings of W. Mooz and others, that other things being equal, the construction period does not affect constant dollar plant costs significantly.

[19] Atomic Industrial Forum, *Licensing, Design and Construction Problems: Priorities for Solution*, January, 1978.

The prospect of continuing design changes means most labor contracts are written on a cost-plus basis, diluting efficiency incentives at the outset. Subsequently, scope changes, tougher quality assurance programs, and refitting and repair work act to boost necessary work in an atmosphere where unnecessary work can profit the contractor and go unnoticed by the owning utility. Morale among workers is also said to be a problem, due to frequent changes, delays, and the standardization with which much nuclear work must, for safety purposes, be performed.

As a result, labor requirements (measured in man-hours per kilowatt of capacity) rose about 143 percent over the period in which the Davis-Besse and Shoreham overruns occurred.[20]

At the present time, most craft laborers on nuclear sites spend only from 30 to 40 percent of their time actually performing their specialty, below comparable utilization rates for other types of construction. In the case of the Shoreham plant, this proportion was even lower, with pipefitters and iron workers having especially low-utilization rates.

Though productivity on nuclear sites is unsatisfactory, there is no clear way of assigning responsibility. Nuclear construction is unique in the frequency of altered instructions. About 40 percent of the design changes in one nuclear project were directly prompted by regulations, and another 35 percent were requested by the utility (though some of these may have been reacting to regulatory urging).[21] These changes can cause ripple effects in terms of low morale or turnover that create their own problems: absenteeism and turnover rates were reported high for many nuclear sites, and strikes or related shutdowns have caused significant delays in several plants.[22]

At a distance, and often even up close, it is impossible to disentangle the various causes of poor productivity at nuclear sites. We are left to observe that a system with very weak performance incentives is, in fact, not performing well. Not only do cost-plus contracts poorly motivate contractors, incentives based on hopes for repeat business can also fail if the purchasing utility does not monitor costs well enough to know when performance could be better. In short, it is hard to specify an achievable improvement in labor performance on nuclear sites but equally hard to believe that one does not exist. Because the amounts are so large, any improvement would bring significant cost savings.

"Remediable" Portion of Nuclear Overruns

There are, therefore, several components of cost overruns that have characterized nuclear construction since its beginning and have grown much worse in recent years. Some of these components were unavoidable, at least by utilities and construction companies, associated with the unanticipated inflation of the 1970s and the upgrading of nuclear safety requirements. The latter are similar to the scope changes that traditionally afflict unique or novel projects. Another set of increases was associated with the changefulness of safety rules. These increases reflect inefficiencies in incorporating changing rules into plants already well along in design or construction phases. Finally, other cost increments probably arose because, in the midst of design changes, contract incentives were weak and cost monitoring lax. This last set of increases is an important source of concern for both utilities and public utility commissions.

There is undoubtedly much variety among plants in the relative importance of each type of problem. Table 16 applies rough-estimating assumptions to a possible overrun in an attempt to place some bounds on our uncertainty. The possible overrun occurs in the late 1970s to early 1980s. A nearly fivefold escalation, to around $1 billion, is thus not implausible. Given the upswing in inflation rates, unanticipated escalation equal to about 65 percent of the original project budget is possible. The total increase in AFUDC is estimated at the same approximate proportion (.80) of the original project estimate as in the Davis-Besse and Shoreham cases (Tables 12 and 13). This total increase is allocated into a nominal and real component according to the logic of Table 15. All other cost increases are allocated into an "other material" category, which excludes unit cost escalation, and an "other labor" category that similarly excludes wage escalation but includes A&E charges.

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[20] Ibid.

[21] G. E. Mason, R. E. Larew et al., *Delays in Nuclear Power Plant Construction*, vol. II, prepared for the U. S. Energy Research and Development Administration, December 1977, pp. 3.3-3.8; Professor Larew, of the Ohio State University, also provided very useful early guidance in present study.

[22] Ibid., p. 4.11.

TABLE 16
ILLUSTRATIVE ESTIMATES OF POSSIBLE NUCLEAR PLANT COST OVERRUN COMPONENTS LATE 1970S, EARLY 1980S

Cost Component	Millions of Current Dollars		Potentially Remediable Increase 20%	30%	40%
Original Cost Estimate		$ 200			
Unanticipated Inflation		130			
Increase in AFUDC:					
Nominal	$138				
Real	22		$ 4	$ 7	$ 8
Other Material Increases:		153			
Design Necessary	103				
Design/Construction/ Management Inefficient*	50		10	15	20
Other Labor Increases:		357			
Design Necessary	240				
Design/Construction/ Management Inefficient*	117		23	35	47
Totals		$1,000	$37	$57	$75

* Inefficiencies include a variety of effects, including complying with changing regulatory climate.

Source: See text.

Within both the material and labor categories, we have split the totals into two parts. The "design necessary" increases represent scope changes, the minimum charges needed to meet the new safety rules. The second category, "design/construction/management inefficiency", represents increases that occur because an initial design was poorly suited to eventual safety rules, because construction had to be interrupted or deferred to accommodate changes, or because there was a general breakdown in efficient cost control due to this difficult construction environment. The totals in both labor and materials categories were assigned to "necessary" or "inefficient" based on the proportion estimated by Bassett (for NRC modification versus its ripple effects, excluding AFUDC). The same proportion, 2 to 1, has been applied to both material and labor, though, as we saw, there is reason for thinking labor inefficiences could be larger.

With no guide to further discrimination, Table 16 shows potentially "remediable" cost increases under arbitrary assumptions. By remediable, we mean costs that could be avoided if everyone involved, utility, A&E, and subcontractors could do it over again with the benefit of hindsight but without the benefit of an improved regulatory environment.

The last three columns of Table 16 show the application of three remedy rates to the real interest charge (due to delay), and the two categories of inefficient cost increases. The largest sums show up in labor, with relatively trivial gains to be gotten, even hypothetically, in interest reductions. The totals, ranging from less than $40 million to more than $70 million, are significant yet hardly overwhelming when measured against the overrun totals.

Though based on partially arbitrary assumptions, the remediable cost estimates show a basic consistency with other observers' informed judgments about cost improvement. Under the 20 percent remedy assumption, the labor savings would be about equal to a 5 percent boost in total labor productivity, an enhancement seen as a practical goal by Booz-Allen for plants like Shoreham.[23] The overall range is slightly higher than, but not that dissimilar to the results of the Theodore Barry audit of Salem 1. The lowest estimate, $37 million, is similar to an estimate made by the New Jersey Public Advocate (based on the Theodore Barry report) of the increases due to management inefficiency in construction of the Salem plant.[24] The highest, $75 million, is close to the estimated 7 to 10 percent reduction in plant costs,

[23] Booz-Allen, "... study of Long Island Lighting Company."
[24] "P.S.C. Unit Asks Investigation of a LILCO Plant," *The New York Times*, March 7, 1979.

that, according to the Mooz and Komanoff studies, come with every doubling of A&E experience. All of these estimates are, it must be remembered, of what might be achievd with experience or under more favorable conditions. It is not clear what proportion of costs could have been avoided by most utilities building their first plants under a set of difficult and worsening cost influences.

D. COAL PLANT COSTS

Coal remains the most important fuel source for generating electricity and the standard means of providing baseload power. Coal accounted for 48 percent of the electricity generated in the United States in 1979 and about 52 percent in the first half of 1980. National Electric Reliability Council projections forecast the continued dominance of coal well into the coming decade.[25] The council forecast includes quite optimistic projections of the rate at which new nuclear reactors can be brought into service. The scarcity and price of hydrocarbon fuels may further tilt coal growth upward, a tilt promoted by recent federal laws that strongly discourage boiler use of oil and gas.

Economics and regulation are assuring that coal-generated electricity will grow more important in our energy future, and so will its costs. As the dramatic rise in coal prices is well known, the surge in the costs of generating plants is also becoming apparent.

This surge stems from the same sorts of causes that affect nuclear plants: general inflation and its influence on interest rates and construction costs; the impact of federal regulations on plant design; and possibly, the effects of contracting and management practices inadequate for a difficult construction environment. However, the magnitude of the increase in coal plant costs has been less than for nuclear and the problems posed for utilities essentially more manageable. In the case of coal plants, federal regulation has sought to protect the air and water environment from specific substances that are byproducts of coal combustion. Though often frustrating in their ambition and complexity, these environmental rules have been expressed in terms more closely linked to performance goals. Hence, they have been more readily translated into engineering specifications.

Overruns

Because less extravagant than for nuclear plants, the overrun record for coal has not been as extensively documented. Few published sources give overruns for specific plants. Available information thus does not allow us to depict coal overruns in the same form and detail as we did for nuclear.

Table 17 presents two kinds of indicators of cost estimation problems in coal plants. Two entries, labeled "plant-specific," are like the previously cited nuclear overruns: They represent an early estimate of a particular facility's costs, versus the actual cost of constructing it.

The other entries, labeled "retrospect," were drawn from a Mitre Corporation report (or calculated using its methods) in which the average costs of constructing a plant in a given year were compared with earlier forecasts of what typical plants would cost by that year.[26] The forecasts, by both public and private sources, were intended to characterize industrywide cost expectations. The ratio calculated from "retrospect" entries thus does not compare specific plants but averages: an average of plant costs on the one hand and an average of different forecasts on the other.

The use of average estimation errors to represent trends in overruns has some drawbacks. Industrywide forecasts do not reflect detailed knowledge of a particular facility's design; to the extent they mistake the design of a "typical" plant, errors arise that are avoidable by plant cost estimators. On the other hand, industrywide forecasts are less prone to any biases arising from a plant estimate being used to promote public or regulatory acceptance of construction. However, industrywide forecasts are done for a variety of purposes, some not entirely disassociated from attempts to influence public policy.

Two other features of the retrospect estimates should be mentioned. According to Mitre, several of the early estimates (roughly, those before 1974) did not take inflation into account; and, because of the way they are calculated, the actual/estimate ratio does not reflect cost increases that occur simply because a plant is constructed later than expected.

On balance, the amount of error possible in the "retrospect" ratios would seem to be more than that likely for a particular plant. The average of the retrospect ratios is, at 1.54, higher than either of the plant-specific ratios—and these were for 1973 and 1974, two years of rapidly accelerating inflation. The actual/estimate ratios calculated from the averaged data probably set an upper bound on the sort of errors most utility estimators could reasonably have made during the period shown in the table.

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[25] National Electric Reliability Council, *9th Annual Review, August 1979.*

[26] *C. Blake, D. Cox, W. Fraize, Analysis of Projected vs. Actual Costs for Nuclear and Coal-Fired Power Plants* (Fairfax, Va.:, The Mitre Corporation, 1976).

TABLE 17
TRENDS IN ESTIMATION OF COAL-FIRED PLANT COSTS
(Unadjusted for Inflation)

Year	Type of Estimate	Estimate $/kW	Actual $/kW	Actual-to Estimate-Ratio
1971	Retrospect[a]	111	157	1.41
1972	Retrospect[a]	122	176	1.44
1973	Retrospect[a]	133	243	1.83
	Plant-Specific[a]	125	168	1.34
1974	Retrospect[b]	150	237	1.58
	Plant-Specific[a]	123	187	1.52
1975	Retrospect[b]	180	275	1.53
1976	Retrospect[b]	205	347	1.69
1977	Retrospect[b]	242	313	1.29

Sources: [a] C. Blake, D. Cox, W. Fraize, *Analysis of Projected vs. Actual Costs for Nuclear and Coal-Fired Plants* (Fairfax, Va.: The Mitre Corporation, 1976).
[b] Calculated from Mitre data using their methods but incorporating updated plant costs from *Steam Electric Plant Construction Costs*, 1977, Energy Information Administration of DOE, December 1978.

Thus, the overrun experience for coal plants has been much better than for nuclear facilities. Moreover, it shows no worsening trend in recent years. While estimating errors are worse than commonly expected of industrial cost estimates, they are not egregiously bad, given the circumstances of the time. For a typical coal plant, a period of seven years can occur between early estimates and completion of the project: reasonable mistakes about inflation could, according to Table 10, account for one to three-fourths of an overrun of, say, 1.55.[27]

Trends in Actual Plant Costs

One major problem confronting coal cost estimators is that the cost of constructing a typical coal plant has risen substantially over time. Table 18 summarizes the strength and variety of this trend. From 1971 to 1977, average-plant costs per unit of nameplate capacity doubled, rising at an average annual rate of 12.2 percent. High and low costs evidence the dispersion in plant costs but underscore the strength of the overall trend.

Though rising more moderately than nuclear costs, coal plant costs were also outpacing inflation, even as measured by specialized construction cost series. The best recent analysis of coal plant cost trends has been done by Charles Komanoff.[28] His study indicates that, adjusted for construction cost inflation by the Handy-Whitman index, average coal plant costs rose 68 percent from 1971 to 1978.[29] Nine-tenths of this "real" cost increase occurred, despite minor economies of colocation, because of environmental rules, especially the requiring of sulfur scrubbers for 1978 plants. The increase was much less than that experienced by nuclear facilities and apparently more easily anticipated. To see why, we can quickly review the most important set of environmental rules, those related to air quality.

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[27] That is, .14 to .38 ÷ 55; see page 19.
[28] As for the previous nuclear plant estimates, we do not make our own adjustment for inflation because translating mixed current dollars into constant costs is a bit elaborate and has already been summarized in Mooz and Komanoff's work.
[29] Komanoff, "Cost Escalation."

TABLE 18
TRENDS IN COSTS OF COAL-FIRED PLANTS*

Year of Operation	Low-Plant Costs (Mixed Current $/kW)	Average-Plant Costs (Mixed Current $/kW)	High-Plant Costs (Mixed Current $/kW)
1971	$126	$157	$180
1972	158	176	221
1973	158	243	292
1974	162	237	331
1975	170	270	360
1976	292	347	499
1977	231	313	377

* Per nameplate capacity, for plants of 300 MW or larger.

Source: *Steam Electric Plant Construction Costs*, 1977, Energy Information Administration of DOE, December, 1978.

EPA Air Quality Rules[30]

Coal plants must meet an increasing number of federal rules related to solid waste disposal, water quality, and land use, but by far the most influential of federal regulations on plant costs have been those which seek to limit air pollution. Federal efforts to clean up the air began with the passage of the Clean Air Act (CAA) of 1970 and were refocused in 1977 amendments to this act. The CAA required the new Environmental Protection Agency (EPA) to establish ambient air quality standards. These standards were to be expressed in terms of ceiling concentrations for five pollutants. EPA was to see that areas that did not meet these standards initially, "nonattainment" areas, were eventually cleaned up; and in those areas that already met the standards, a court ruled that EPA had to develop rules to "prevent significant deterioration" (PSD).

Whether an area is determined to be a nonattainment area or one subject to PSD rules, the chief distinction governing a plant's costs is whether it existed when the CAA (or its amendments) passed, or was a new plant, subject to "New Source Performance Standards" (NSPS). The translation of air quality standards into a set of agreed-upon rules, specific enough to be enforced on existing facilities, has proven a frustrating exercise. For new plants, on the other hand, the NSPS have been, while not always predictable, specific when they came and definitely enforceable.

Under the 1970 act, EPA set NSPS in terms of ceilings on the volume of pollutants per unit of output. For coal plants, these ceilings were applied to three "criteria pollutants," particulates, sulfur oxides, and nitrogen oxides, and expressed per millions of Btus. Ceilings were supposed to reflect the "best available control technology," that is, the most effective system for removing the pollutants feasible within the period contemplated. Nevertheless, it might also be possible to meet the criteria by using particular types of fuel, such as low-sulfur coal or oil.

In 1977, the amendments to the CAA substantially changed the ceilings for criteria pollutants. Now, pollutants in a fuel must be reduced by a specific percentage. In most cases, this approach will require the use of particular types of equipment, such as stack scrubbers, regardless of the quality of the coal burned. In addition, for areas subject to the PSD rules, the installation of best available control technology is generally required, as is demonstration that local air quality will be affected by a new plant only within limited margins.

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[30]The following discussion draws heavily from H. Landsberg et al., *Energy, The Next Twenty Years* (Cambridge, Mass.: Ballinger, 1979), pp. 374-84.

Effects of NSPS

The application of the NSPS to electric utilities can be divided into two periods. First came the period following the passage of the 1970 act. Most of the plants affected by these standards did not come into operation until 1976-77 at the earliest. Second, regulations implemented pursuant to the 1977 amendments will influence plant costs for most of the 1980s.

There is much variety in the specific standards plants have to meet within each of these periods. Plant costs may be affected by its location (nonattainment versus PSD area), by its time of completion, and by the type of coal it uses. During much of the 1971-77 period, there has been continued argument about the NSPS, such as, for instance, the type of equipment practical and economic enough to be considered the "best available control technology." However, EPA air standards have posed far fewer cost and performance burdens than the NRC's nuclear rules for several reasons.

First, standards were expressed in terms of relatively simple performance guides; a few, physically identifiable by-products of combustion were to be kept under specified ceilings over some period of time. The arbitrariness that necessarily goes into defining "safe" levels of risk for people was not removed, but it was incorporated in the setting of the ceilings themselves, not left to cloud future performance rules.

Second, ceilings on criteria pollutants were linked to specific pieces of equipment. Basing ceilings on "best available control technology" assured that a definite system was contemplated, even though its appropriateness was questioned and exact cost, before widespread use, unknown.

Last, most regulatory requirements either were known before a plant went into construction or were anticipatable at that time. Plant designers could incorporate suitable modifications, and plant work schedules could be arranged so as to minimize duplication and disruption.

Environmental rules thus pose challenges in the estimation and control of plant construction costs more modest than those posed by their nuclear counterparts. Nevertheless, their impact has been substantial and is likely to grow more so as the 1977 amendments take hold.

Cost of Environmental Rules

Table 19 presents estimated costs of complying with environmental rules applicable to new coal plants. The estimates are divided into those reflecting standards now in effect and those anticipated to flow from implementation of the 1977 amendments. Two of the estimates are only for specific pieces of equipment, chiefly the stack scrubbers and particulate removal systems required by the Clean Air Act. The first two estimates are more comprehensive, however, including the costs of noise abatement and reduced environmental disruption during construction, mandated by other environmental and health statutes.

Probably the most complete and detailed estimates are those taken from the Komanoff study cited earlier. These estimates include conservative assumptions about NSPS (that a typical 1978 plant slightly exceeded the required improvements and that a 1988 plant will significantly exceed the new NSPS) and costs of equipment (adding a contingency factor to early engineering cost estimates). The estimates of Komanoff (a frequent consultant to environmental organizations) are the largest, indicating that the unit cost of coal plants increased by two-thirds to meet existing standards and must double again as the new NSPS become effective. The increase to meet 1978 standards was sufficient to account fully for the observed rise in plant costs up to that year.

Leonard Reichle, of Ebasco Services, made an estimate of meeting the new NSPS that is similar in apparent inclusiveness. His estimate envisions much the same equipment as Komanoff and adds a cooling tower. It is about the same in absolute terms, at $397 per kilowatt of capacity. The last estimate for 1980's operations is from preliminary figures obtained from the Edison Electric Institute. It is also close to the prior two.

Less comprehensive estimates have been extracted from recent papers by Gibbs and Hill and from a Resources for the Future energy policy study. These estimates are considerably below the previous ones. Part of this difference is due to the inclusion of fewer items but the costs for included items are also less than comparable figures in Komanoff and Reichle.

Two basic points are emphasized by Table 19. The cost impact of environmental rules is large, possibly doubling the real cost of coal-fired power by the end of the next decade; and there is uncertainty about typical plant costs, as indicated by the dispersion of the cost estimates. Uncertainty about the types of equipment that will characterize a "typical plant" by a particular date undercuts the reliability of industrywide cost forecasts; but plant cost estimators, with knowledge of the plant's physical characteristics, location, and planned licensing schedule, are in a better position to anticipate regulatory requirements.

TABLE 19
SELECTED ESTIMATES OF COSTS OF COMPLYING WITH ENVIRONMENTAL RULES APPLICABLE TO COAL PLANTS

Reflecting Environmental Rules Applicable to Plants In Service 1978		**Reflecting Environmental Rules Applicable to Plants In Service by Late 1980s**	
Compliance Cost Estimate (In 1979 $/kW, Including IDC)	**Specifically Includes**	**Compliance Cost Estimate (In 1979 $/kW, Including IDC)**	**Specifically Includes**
$240[a]	• Particulate Removal by ESP • SO_2 Removable by Scrubber • NO_x Removal by Boiler Modifications • Solid Waste/Liquid Discharge/Noise/ Construction Pollution Control	$360–470[a]	• Baghouse Filter or Improved ESP • Regenerable Scrubber • Postcombustion Control of NO_x • Improved Systems for Waste/ Discharge/ Noise/Construction Pollution
		$397[b]	• Particulate Removal by ESP • SO_x Removal by Scrubber • NO_x Removal • Solid/Liquid Waste & Noise and Construction Removal • Cooling Tower
		$141[c]	• Scrubbers • Sludge Disposal • Cooling Towers
$111[d]	• Particulate Removal by ESP • SO_2 Removal by Scrubbers	$420[e]	• Scrubbers • Precipitators • NO_x Control • Ash/Sludge Disposal • Cooling Towers • Waste/Noise/ Construction • Pollution Control

Sources: [a] C. Komanoff, "Cost Escalation."
[b] L. Reichle, "The Economics of Nuclear versus Coal," (Paper presented before the Richmond Society of Financial Analysts, October 1979).
[c] Gibbs and Hill, "Economic Comparison of Coal and Nuclear Electric Power Generation," January 1980, adjusted for IDC.
[d] S. Schurr et al., *Energy in America's Future*, (Baltimore: 1979) Johns Hopkins Press, p. 276; adjusted for inflation and IDC.
[e] Preliminary estimate by the Edison Electric Institute, obtained in a telephone conversation with Tom Brand of EEI, July 9, 1980.

Cost Increases and Overruns

Once requirements are translated to equipment types, uncertainty about costs and performance may still remain. However, the cost uncertainty is likely to be of the same order as that which characterizes new project estimates in general. As noted in the first section of this chapter, preliminary estimates may err by up to 25 percent but be rapidly improved as experience is gained and techniques proved out.

Changing environmental rules are not posing unmanageable problems for cost estimators. Though we do not have any plant-specific data on coal overruns, we can add some of the explanatory factors already noted. Table 20 presents a simple summation of potential explanations. According to the earlier discussion of unanticipated inflation, a plant requiring seven years to design and build might reasonably encounter from 14 to 38 percent unexpected inflation (see Table 10). Given more modest overall cost increases, an AFUDC increase equal to 10 percent of original budget is reasonable (versus one equal to 80 percent of the original estimate in the case of a five-fold nuclear overrun). If we increase the smaller of the estimated costs of complying with 1978 environmental rules to account for unincluded items, we get a range between this and the higher Komanoff estimate that is equal to from 40 to 65 percent of the real costs of pre-Clean Air Act plants.

All told, as Table 20 shows, we could thus explain current dollar overruns of from 64 to 113 percent by the simple ingredients of inflation, interest, and changed environmental rules. The fact that most overruns have been a good bit less than this means that estimators have been correctly anticipating the bulk of the increase due to changing environmental rules. The remaining overruns could be attributed to uncertainty about the need for relatively minor equipment components or about the exact costs of major components.

TABLE 20
POTENTIAL INFLUENCES ON A "TYPICAL" COAL PLANT OVERRUN
(As Proportion of Original Estimate)

Original Estimate:	1.00
Unanticipated Inflation:	.14-.38
Total AFUDC Increase:	.10
Real Increase in Plant Costs due to Environmental Rules:	.40-.65
Total	1.64–2.13

Reference: Typical Coal Plant Overrun 1.55

There are substantial reasons for thinking the potential for inefficient construction practices is much less significant for coal than for nuclear. There is, of course, less cost increase to be explained. Interrupted schedules, changed equipment tolerances, and refitting of major components are also much less characteristic of coal projects.

The chief uncertainty in coal construction contracting is inflation in local labor and materials. While having serious cost consequences, this uncertainty need not pose insuperable contracting challenges, so long as the scope of work can be well defined. Escalation clauses can transform a cost uncertainty into a fairly adjusting system that does not encourage overspending. This and other contracting methods to control overruns are treated more fully in Chapter Three.

Coal Overruns in Regulatory Context

To repeat, coal plant overruns have been far less dramatic than those for nuclear plants, and mostly explainable by inflationary effects that could not have been anticipated. These overruns have taken place against a backdrop of a continuing increase in the real costs of building generating units, an increase due to changing environmental rules. The overrun record indicates that most of these increases were anticipated by estimators. The way environmental rules are applied to coal indicates that this can also be true in the future.

Yet, because of the significance of coal plants in utilities' rate bases, large cost boosts merit rigorous attention. Future plant costs will increasingly include equipment types subject to estimation uncertainty. If some forecasts are correct, about half of the cost of generating electricity from coal will be for environmental equipment by the 1980s. The success of utilities in installing this equipment in the most economical fashion will have an important influence on costs of service.

E. TRENDS IN TRANSMISSION AND DISTRIBUTION COSTS

Outlays for transmission and distribution (T&D) facilities constitute a major portion of the expenditures utilities must make and recoup to service consumers. Especially for dispersed residential consumers, these T&D outlays heavily influence costs of service.

T&D costs are for lines of various voltages and stations used to "transport" electric power. These costs usually are not analyzed by specific project but by broad aggregates in terms of distance, voltage carried, and so forth. So measured, most T&D costs have risen only moderately in recent years, generally within or below rates of construction cost inflation. Some other cost factors may also be influencing T&D outlays, including the difficulties of adapting to slower growth in electricity demand and heightened expenses of distribution.

Cost Trends

Table 21 shows the growth in total T&D expenditures from the early 1970s until the end of the decade. Though this total is substantial, ranging from one-fourth to one-third of utilities' capital spending, it has grown only modestly over the tabled period. An average growth rate of 4.6 percent is below any appropriate inflation rate and so indicates a decline in real volumes of T&D activity in the last 10 years. This decline in real activity is consistent with the dampened prospects for electricity demand growth in light of the 1973 embargo and its aftershocks.

TABLE 21
COMPARISON OF VOLUMES AND PROPORTIONS OF TRANSMISSION AND DISTRIBUTION OUTLAYS, 1971 TO 1979

	1971 to 1973 Average	1977 to 1979 Average
Total Transmission and Distribution Outlays (in Millions of Current $):	$3,559	$4,656
Average Annual Growth (in percent p/a):	---- 4.6% ----	
Major Components as Proportion of Total:		
Overhead, 345 KV & Above	.13	.15
Overhead, 69 to 230 KV	.14	.13
Underground, 230 to 345 KV	.01	.01
Underground, 69 to 161 KV	.01	.01
Subtotal, Transmission Lines:	.29	.30
Overhead, 69 KV and Below	.32	.31
Underground, 69 KV and Below	.15	.15
Subtotal, Distribution Lines:	.47	.46
Stations	.24	.26
Totals (From Unrounded Data)	1.00	1.00

Source: *Electrical World*, Annual Statistical Report, March 15, Various Years.

The remainder of Table 21 summarizes changes in the proportionate importance of various types of T&D. These proportions have remained quite stable over the decade, indicating that the slowdown in growth affected all facilities. The small shift from .13 to .15 in transmission lines above 345 kV may indicate that scale efficiencies continue to promote a shift toward larger lines, even though overall growth is slowing. The most important component of the T&D system, from a cost standpoint, remains overhead distribution lines.

Trends in Unit Costs

The change in total T&D expenditures resulted from changes in both activity levels and the unit costs of the various facilities. Table 22 presents the trends in average unit outlays, by type of T&D facility. The trends were estimated from the Annual Statistical Report of *Electrical World*. Unlike the previously cited costs for generation facilities, these costs do not apply to a specific facility but are averages per some standard measure of facilities. A variety of shifts in terrain or other construction conditions will thus influence average T&D costs.

TABLE 22
AVERAGE UNIT OUTLAYS FOR TRANSMISSION AND DISTRIBUTION FACILITIES
(In Current Dollars)

	Transmission Lines				Distribution Lines 69 kV and Below		
	Overhead		Underground				
Year	345 kV Above ($000/ mi.)	69 to 230 kV ($000/ mi.)	230 to 345 kV ($000/ mi.)	69 to 161 kV ($000/ mi.)	Over-head ($000/ mi.)	Under-ground ($000/ mi.)	Sub-stations ($000/ mi.)
1971	$148	$ 62	$2,154	$557	$27	$59	$ 9
1972	123	66	827	340	18	46	8
1973	172	61	1,043	653	24	38	9
1974	182	71	600	527	26	35	12
1975	188	89	2,940	215	28	29	12
1976	267	79	1,021	242	37	40	14
1977	243	79	1,897	377	37	44	13
1978	255	88	2,069	158	55	72	12
1979	189	107	1,104	609	66	88	15
Avg. Annual Rate of Increase							
1971 to 1979	7.6%	6.4%	NM	NM	15.1%	6.1%	8.3%

Source: *Electrical World*, Annual Statistical Report, March 15, Various Years.

Of the seven types of T&D facilities shown, the two types of underground transmission lines show no discernible trend. This occurs because their averages are dominated by a few major projects each year, and reflect the difficulty of those projects much more than trends in construction costs. Underground transmission constitutes, however, only about 2 percent of total T&D expenditures.

The remaining five facility types also show erratic year-to-year movement. However, there is a clear upward trend evident. In all five series, average unit outlays rose at paces of from about 6 to 15 percent per year. The more modest rates were incurred in overhead transmission lines and in underground distribution; the increase for stations was somewhat higher and the increase for the important overhead distribution lines was higher still.

Input Inflation

That the increase in unit outlays stems essentially from increasing costs of construction inputs can be seen by comparing these increases to Table 23. It shows the average rates of increase in relevant T&D inputs, according to Handy-Whitman indices. Except for overhead distribution lines, the relevant rates for inputs are greater than the rates for unit outlays in all cases. Major components of overhead transmission rose, according to Table 23, by between 8 and 10 percent, while unit outlays for this category were up at 6.4 percent to 7.6 percent. Similarly, outlays for stations and underground distribution were up at slightly less than the rates registered in their inputs.

TABLE 23
AVERAGE RATES OF INCREASE IN TRANSMISSION AND DISTRIBUTION INPUT COSTS, 1971 TO 1978

Cost Element	Average Increase (% Per Annum)
Total Transmission	9.1%
Overhead:	
Towers	8.1
Poles	10.0
Conductors	9.1
Underground:	
Conduits	7.7
Conductors	8.7
Total Distribution	8.8
Overhead:	
Poles and Towers	10.0
Conductors	9.2
Underground:	
Conduits	7.5
Conductors	7.6
Substations	9.8
Reference	
All Steam Generation	9.2
Fossil Generation	9.5
Nuclear Generation	7.9

Source: *Electric Utility Cost Trend Tables*, Handy-Whitman Bulletin no. 197, Table E-1 (Baltimore: Whitman, Recquardt and Associates).

Modest differences between input inflation rates and trends in unit outlays may be traced to a number of causes, some statistical, some not. A slight difference in the time period over which outlays and inputs were measured could explain these differences, as could the "bumpiness" of the yearly outlay data from which the trend was calculated. It is also possible that faced with declining growth, T&D planners were able to select more efficient projects, economizing in that way.

A different impression registers in the case of overhead distribution. The trend in outlays is significantly above that of any relevant input: 15.1 percent versus input inflation in the 9 to 10 percent range. Here again, statistical considerations may explain part of the difference, but more fundamental causes are also possibly at work. It is possible, for instance, that the increased difficulty and expense of construction in already built-up areas are registering on distribution charges. Without evidence, however, this must remain only speculation.

Forecasting Errors

Given only modest cost increases, and most of these in line with inflation, it would seem that overruns on T&D projects should also be modest and explicable in terms of unanticipated inflation. Costs, on either an estimated or actual basis, are not generally available for specific T&D projects, so we could not calculate an actual/estimate ratio in the preferred way. However, the Annual Statistical Report in *Electrical World* contains interesting indications of potential estimating problems.

Each year, this report shows both actual expenditures on various T&D facilities for the previous year, as reported by utilities, and these same utilities' forecasts of expenditures for the next year. Actual and forecast volumes of real activity in line miles, and so forth, are also included. It is possible, therefore, to compare the average unit outlays forecast for T&D each year with the actual unit outlays incurred. The differences between actual and forecast outlays on an industrywide basis, will reflect a mix of influences, including unanticipated inflation, and changes in the timing, scale, and type of projects actually built.

Table 24 summarizes the results of comparing average unit outlays forecast with those actually incurred. Reflecting the variety of cost and other factors at work, the yearly ratios fluctuate widely, with no series showing a uniform tendency to either over- or underestimation. As with the unit cost entries, the two categories of underground transmission lines fluctuate most widely.

TABLE 24
RATIO OF ACTUAL AVERAGE UNIT OUTLAYS TO ONE-YEAR FORECAST UNIT OUTLAYS, FOR TRANSMISSION AND DISTRIBUTION, 1971 TO 1978
(In Current Dollars)

	Transmission Lines				Distribution Lines		
	Overhead		Underground		69 kV and Below		
Year	345 kV & Above ($000/mi.)	69 to 230 kV ($000/mi.)	230 to 345 kV ($000/mi.)	69 to 161 kV ($000/mi.)	Over-head ($000/mi.)	Under-ground ($000/mi.)	Sub-stations ($000/mi.)
1972	1.14	.98	1.06	.77	.70	.78	.88
1973	.91	1.77	.74	1.56	1.28	1.55	.95
1974	1.29	1.28	.84	.57	1.05	1.03	1.08
1975	1.42	1.35	1.77	.85	1.17	.83	1.00
1976	1.28	.81	.92	.70	1.42	1.22	1.06
1977	1.15	1.03	.12	1.47	1.03	1.03	NA
1978	1.36	1.05	2.03	.92	1.44	1.55	.93
1979	.81	1.05	1.90	4.65	1.19	1.19	.93
Avg. Ratio:	1.17	1.17	1.18	1.44	1.16	1.15	.98

Source: *Electrical World*, Annual Statistical Report, March 15, Various Years.

The lack of stability in year-to-year figures underscores their dependency on the scheduling of actual projects as well as the costing of these projects. For instance, the actual unit outlays for a particular year may be much less than forecast because several relatively expensive projects were deferred or cancelled. It is impossible to separate such influences on a year-to-year basis, but, if the deferral of projects is an important influence, it should be diluted somewhat if ratios are calcuated over several years.

The bottom row of Table 24 presents the average forecast/actual ratios for 1972 through 1979. Interestingly, the average is positive in all but one case. The ratios for the relatively stable series, overhead transmission and distribution, are remarkably similar, all being in the 1.16 to 1.18 range.

The reason for the apparent tendency to underestimate unit outlays, on average, is not clear. It can be attributable in only a small way to inflation. Since T&D projects represent the sort of repetitive construction in which experience should at least eliminate biases, it probably was not the result of errors in costing specific projects. Therefore, some sort of errors in anticipating the types of projects that will be undertaken probably plays a major part. Even if true, the significance of this last point is still a bit murky. It could mean that utilities may be quite accurate in estimating the costs of a well-defined T&D project (one year ahead) but may not be quite as good at forecasting the types of projects that will be needed on a systemwide basis.

Summary

T&D outlays are generally moving upward at moderate rates, in line with or below inflation. The exception to this rule is in the case of overhead distribution lines. Costs for these lines, which represent nearly one-third of total T&D expenditures, have been going up much more rapidly than the costs of their inputs. The reason for this excess is not clear, however, on the basis of data examined here.

In addition, there may be a tendency for utilities to underestimate average unit outlays for T&D. If true, this underestimation more likely traces to failures in forecasting types of T&D projects required than to major underestimation of the costs of specific projects.

Chapter Three

REGULATORY IMPLICATIONS

A. INTRODUCTION

According to Chapter Two, electric utilities' plant costs have risen dramatically over time. With the exception of transmission and distribution costs, this rise has substantially exceeded relevant rates of input inflation. A second problem is linked to this rise in real costs: Utilities have consistently underestimated outlays for new plants, to a degree that renders initial cost estimates almost useless in many cases.

These problems would be worrisome in any industry. As discussed in Chapter One, there are reasons for special concern when they occur in regulated public utilities. The incentives to choose levels and types of capital plant efficiently have long been suspect under cost-of-service regulation. While biases toward overspending are far less likely in today's environment, the effectiveness of regulation in actively encouraging efficiency is still uncertain. In the case of power plant cost overruns, suspect incentives thus join with frustrating performance to justify interest by regulators.

Such interest could apply to either of two periods. These are (1) the short term, in which plants now under construction will be completed and seek to enter the rate base, and (2) the midterm span over which new plants are planned, with completion anticipated around the turn of the next decade. Options open to regulators plainly differ between these two periods. In the first, they are limited to decisions on the approval of cost incurrences already undertaken; while in the second, many more choices to prevent or control overruns are open.

However, in both cases, the same questions are raised: What causes an overrun, what portion is avoidable, and what practices could avoid this portion? The two cases are linked in another way. The most important determinant of future plant-spending decisions by utilities may be regulators' treatment of current overruns. Actual decisions on rate basing of major plants could exert a far more forceful influence on new plant orders than any set of newly developed rules or promised review criteria.

For these reasons, we have not divided the discussion of regulatory implications by time period. Rather, we have organized the discussion of cost control problems according to the levels at which these problems occur and might be remedied. These levels are three: contract relations within a construction project, management of the project by a utility and/or its A&E, and public utility commission policies toward construction projects.

Issues in cost control at the project level concern regulators because requirements for effective control practices can be applied in review proceedings. This includes any practice that might reasonably be used by a utility, its A&E, or subcontractors.

Regulators may also want to consider what actions by other public bodies could assist in controlling costs. The probability or improbability of such assistance forms an important influence on future cost trends.

The remainder of this chapter is organized in the order just mentioned. First, however, it reviews some specific reasons for increasing plant costs and outlines an economic framework for looking at ways to control them.

B. PROJECT COSTS: PROBLEMS AND BASIC CONTROL CHOICES

Chapter Two noted several specific problems that have prompted poor cost performance in power plant construction. These problems can be divided into two types: those that unavoidably boosted costs over time, and those that frustrated cost control, leading to cost increases that might have been avoided. The most prominent examples of the first type are input cost inflation and design changes. To the extent inflation in input costs only keeps up with economy wide price movements, no change in the burden of a facility's construction occurs. It follows that no damage is done if project managers (or regulators) fail to anticipate the general inflation component of input cost movements. As we saw in Chapter Two, though, inputs to power plant construction have risen at a more rapid rate than economy wide prices. From 1974 through 1978, steam electric power plant inputs rose almost half again as fast as the GNP price deflator.

This rise in utilities' input costs was close to that registered in the construction industry generally. The increases in input costs appear, then, to be imposed on utilities by broader economic trends. The challenge posed is thus not one of control but of anticipation. Both utilities and regulators should consider the likelihood that construction costs will continue to outpace inflation as they assess plans for new plants.

A broadly similar argument holds for the portion of design costs that actually procured improvements in facility performance. These costs are the result of externally imposed mandates. Like excessive input inflation, they represent changes in the real costs of providing power by the chosen system; they should be recognized in weighing the necessity of new plants.

Because state regulators must react to, rather than influence, these outside factors, we will emphasize the second type of problem, the frustration of cost control. Both inflation and design requirements have been characterized by an unpredictability that undercuts normal methods of managing project costs. Inflation has been highly uncertain over time and among different types of labor and materials. Design requirements for nuclear facilities have been in continual flux, with no stable definition of structural or performance criteria. Even for coal plants, environmental requirements have been marked by two major legislative overhauls and continuing imprecision on a plant-specific basis.

Uncertainty about costs and scope of work undercuts project cost control. To see why, we can look at two basic ways of managing most economic activities.

Markets Versus Managerial Hierarchies

Major utility projects are organized according to a complex set of relationships among the units involved. The major units usually include the utility, architecture and engineering staff, construction management staff, and many types of skilled and unskilled labor as well as equipment suppliers. The relationships among these units are of various types. Most relationships can, however, be divided into two basic sorts, and this division is a useful way of understanding the problems and changes affecting power plant construction. The first sort of relationship is the market arrangement that usually exists between independent companies or individuals; the second is the hierarchical or bureaucratic arrangement that usually characterizes the management of a single enterprise. In a market arrangement, expectations of efficiency rely upon having a well-defined good or service that several competing sellers can provide. If both buyers and sellers are well informed about their choices, if the cost of making individual transactions is small relative to the value of the product, and if some other conditions are met, markets generally work well. An especially desirable characteristic of a market is its incentive for efficiency. For once a product's price is determined, sellers benefit fully from cost savings in production.

The second type of arrangement, a managerial hierarchy, is typified by the employer-employee relationship in a company. However, the same general conditions hold between a company's headquarters and its subdivisions. Subordinates' (subdivisions') responsibilities are specified in detail and subject to close monitoring and supervision. Faith is placed not in bargains among independent parties, but in the close working together of an organization. To work well, information available to supervisors must be adequate to judge and direct subordinates, and supervisors must be able to exert effective control over these subordinates. In major construction projects, these conditions require experienced management with access to sophisticated tools for information and control.

Both market and managerial arrangements exist and complement each other in most industries, including power plant construction. Up until the mid-1960s, market-type arrangements obtained at particularly crucial junctions in power projects, between utilities and construction companies and between prime and subcontractors. In the late 1960s and 1970s, this changed as market-type arrangements became less practical.

The replacement of markets with managerial chains stretching down from utilities through prime and subcontractors was accomplished in response to a number of strong forces. Most arguments about how to get a handle on project costs reduce to one of two approaches: trying to make market arrangements work, where still possible; and, where managerial links are unavoidable, stiffening these links with the best types of intraorganization controls. Like the coexistence of markets and hierarchies, these approaches are complements, not adversaries. The aim is to find the right combination of market and managerial tools to handle major projects, given the sharply altered environment under which power plant construction must now be conducted.

The next two sections of this chapter are about these two approaches. The first discusses contracts, since these are the pivot of market efficiency in construction projects; next we discuss the changes utilities have already made and are considering making in improving project management techniques.

C. CONSTRUCTION CONTRACTS

In construction projects, the only practical way of enjoying market efficiencies is through satisfactory contracts. When a utility builds a power plant, it is mostly buying services from one or several sellers over a period of time. Only if contracts can be written, negotiated, and enforced to satisfy the requirements of effective markets will utilities get efficient performance from them. Otherwise, contracts can promote waste, or at best serve to establish what is in fact a managerial relationship between the parties.

Contract Purposes

Contracts must specify performance precisely enough so that bidders can make intelligent bids (and live up to them), and buyers can judge intelligently among them. In addition, the costs of offering and awarding contracts must be kept to a minimum, while competition among bidders is preserved.

Any one of these conditions can be satisfied easily. The trick is to accomplish all three. Precision of contract terms is improved when jobs are broken up into smaller units, to be accomplished over short periods, after all conditions and requirements have been determined precisely. When the scope and period of the job are well known, a bidder should have little trouble estimating work requirements or sticking to estimates; at the same time, short-time horizons considerably ease problems of labor and material cost estimation.

Breaking jobs up into a sequence of small increments brings penalties, however. The smaller the job the larger, in proportion, will be the mostly fixed costs of negotiating contracts. The most important transaction costs are likely to be not the dollar costs of negotiation but the delays in project completion that come from frequent negotiation of a sequence of small contracts. Delays could be reduced, of course, by setting very tight time limits on bid submissions after completion of each job in a sequence. In such cases, though, only one or a very few contractors might know enough about the status and conditions of the project to bid intelligently. Therefore, effective competition, which underpins all claims of market efficiency, would be lost.

The competing considerations of adequate job definition, minimizing transaction costs and preserving competition, set bounds on what kinds of jobs may be let by competitive bidding. Jobs must be large enough to justify the effort required by both bidders and utility evaluators, and they must be well defined in terms that are understandable to a number of bidders who have sufficient advance warning to enable intelligent estimation. In the case of many conventional construction projects, these conditions are readily met. An experienced A&E lays out a complete project schedule and job description. The timing of various jobs, including the engineering work needed to support them, is determined by critical path methods. Jobs can thus be specified with sufficient precision and advance notice to elicit competitive bids. However, power plant construction increasingly has been subject to problems that render this happy world largely obsolete, even with a variety of new contract types.

Firm Fixed Price Contracts

Firm fixed price contracts are the simplest means of arranging for the performance of a construction job, and in form at least, the closest to ordinary market transactions.[1] A purchaser announces a specific job to be performed and seeks bids from qualified contractors. Bidders commit to meet all performance requirements at a price that will not change as long as these performance requirements do not. Purchasers evaluate the bids with only two criteria in mind: the lowness of the bid price, and the probability that the bidder will do a satisfactory job on time.

If job requirements can be specified and maintained, fixed price contracts strongly promote efficiency. Contractors make whatever they save on a job (or lose by overruns) because their price is set. Since they know this when they bid, they should, unless colluding, bid on the basis of efficient performance. Further, bidders should continually seek to improve methods for performing jobs to enable them to win future bids. In sum, efficient contractor performance is encouraged, and purchasers should benefit from competitive bidding.

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[1] The best general background on contract incentives is to be found in F. M. Scherer, *The Weapons Acquisition Process*, (Boston: Harvard University Press, 1964). Much of the discussion of incentives related to utility contracts is based on Theodore Barry and Associates, *A Survey of Organizational and Contractual Trends* (Los Angeles: 1979).

However, if a job's requirements cannot be defined satisfactorily at the outset, or are subject to major change, these advantages will be overturned. If a contractor cannot realistically estimate his job costs, he will probably be unwilling to enter into a fixed price agreement (unless he adds a very large "risk premium" to his bid). If he expects a change in these requirements, he may submit a deliberately low bid, seeking to win entry and advantage by a commitment that he will not have to honor.[2]

A contractor may be unable to estimate costs on a job because either the technical specifications, or "scope," of the job are unclear or because he does not know what his own unit costs will be. Both problems are obviously present in power plant construction. They are remediable, within limits, by altered contract designs.

Incentive Price Contracts

Moderate uncertainty about the scope of a job can be relieved by contracts in which the final price will fluctuate with costs but still leave contractors with incentives to economize. "Incentive price contracts" set a target for project costs and specify the price, including contractor profits, that will be earned if this target is hit. Then the contract establishes provisions for sharing the penalties for overruns (or benefits for underruns) between the contractor and the purchaser.

These provisions may be framed in a number of ways, but they all have several common traits, tendencies, and limitations. Overrun penalties are expressed by a rule that generally does not differ much in its effects from a proportional reduction in a contractor's profit rate with cost escalation. Thus, an incentive contract might provide that a contractor would earn 15 percent of direct project costs if the target was hit but would receive 1 percent less for every 10 percent escalation in costs above this target.

This reduction in a contractor's profit proceeds up to some specified point. The wider the range between target and this point, the broader the range over which the contractor will have some incentive to control costs. The wider this range, however, the less the penalty must be within any segment of it, assuming the proportional penalty is held constant. The proportional profit penalty may be enlarged, of course, say to 1 percent point off profits for every 1 percent overrun; but, given fairly firm acceptable maximum and minimum rates, this reduces the penalty range.

Incentive contracts can work well if arranged to operate with greatest force on the actual choices a contractor has in controlling costs. This will be true if the range of uncertainty about project costs at the outset is similar in magnitude and mean to the range over which the contractor will be able to control costs, once the project has begun. If these ranges are not similar, incentives will be weak or nonexistent and overcome by other pressures. For instance, a contractor may be willing to accept small cuts in profit rates if total revenues grow enough.[3]

Getting contract incentives to fit eventual control choices can be difficult. Table 25 illustrates why. It shows the effects of overruns under an incentive contract that allows profits to vary from 5 to 15 percent of incurred costs. This is a relatively large variation in permitted profits and thus emphasizes the potential effects of incentives. The profit rate is reduced proportional to cost escalation, from 15 percent at target to some end point overrun figure (above which it is flat at the minimum 5 percent). The column headings show alternative end points as a ratio to target cost. The first column shows results when the minimum profit rate of 5 percent is reached at 1.1 times target costs. Columns to the left show much more extended ranges, up to double target costs.

Each row is calculated for a specified "zone of effective cost control." This is the range over which a contractor finds he can actually influence costs, given the requirements of the job (better and better defined as work progresses). In most cases, this zone of cost control is likely to be fairly limited for a particular job, assuming there are minimum physical requirements to be met and a practical maximum on the inefficiencies that could in any case be tolerated.[4] In addition, there is no necessary reason for this zone to be centered near the target cost itself. In Table 25, we have assumed that effective control is about 10 percent of costs and might turn out to be near the target, or very far from it.

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[2] E. W. Merrow, S. W. Chappel, and C. Worthing, *A Review of Cost Estimation in New Technologies, Implications for Energy Processing Plants* (Santa Monica, Calif.: RAND Corporation, R-2481-DOE, July 1979), p. 22.

[3] It is impossible to write an exact specification of the goal of contractors into contract terms if only because these differ among businesses, and over time, even for the same business. It should also be remembered that the "profit" in an incentive contract depends for its definition on the cost accounting system used; it may correspond to the actual excess of revenues over properly assigned costs.

[4] The inefficiencies possible on a complex job may be larger, as these could compound delay and management problems at several levels.

TABLE 25
EFFECTS OF OVERRUNS UNDER 15 PERCENT - 5 PERCENT INCENTIVE CONTRACT, WITH ALTERNATIVE INCENTIVE RANGES AND SPECIFIED ZONES OF COST CONTROL
Shifts in Profit as Percent of Costs
(Percent Change in Total Contract Revenues)

Zones of Effective Cost Control, as Ratio of Target Cost	End Points of Incentive Overrun Range, as Ratio of Target Costs 1.1	1.3	1.5	1.7	2.0
1.0-1.1	15.0-5.0% (+0.4%)	15.0-11.7% (+6.8)	15.0-13.0% (+8.1)	15.0-13.6% (+8.6)	15.0-14.0% (+9.0)
1.1-1.2	5.0 (+9.0)	11.7-8.4 (+5.9)	13.0-11.0 (+7.2)	13.6-12.2 (+7.7)	14.0-13.0 (+8.1)
1.2-1.3	5.0 (+8.3)	8.4-5.0 (+4.9)	11.0-8.0 (+6.4)	12.2-10.7 (+6.9)	13.0-12.0 (+7.4)
1.3-1.4	5.0 (+7.7)	5.0 (+7.7)	9.0-7.0 (+5.8)	10.7-9.3 (+6.3)	12.0-11.0 (+6.7)
1.4-1.5	5.0 (+7.1)	5.0 (+7.1)	7.0-5.0 (+5.7)	9.3-7.9 (+6.3)	11.0-10.0 (+6.7)
1.5-1.6	5.0 (+6.7)	5.0 (+6.7)	5.0 (+6.7)	7.9-6.5 (+5.3)	10.0-9.0 (+5.7)

Source: Calculated according to assumptions in text.

For each assumed end point and control zone, the first entry shows the shift in profit rates that would apply under the incentive contract if the contractor let costs slip all the way from the bottom to the top of his control zone. After this shift in profit rates is shown, parenthetically, the change in total revenues that would occur by virtue of the same slippage.

The sharpest shift in profit rates occurs, of course, when the zone of control exactly matches the overrun incentive range. A contractor would, by failing to control costs in this case, cut his rate of profit by two-thirds. Equally significant, the interaction of cost escalation and incentive clauses means that total contractor revenues would barely increase at all. Strong and relevant incentives would exist to minimize costs.

This situation requires luck or some pretty accurate forecasting of target costs. If incentive clauses are set at 1.1 of target, and contractors find they must exceed 1.1 in any case, incentives evaporate. No penalties are incurred, and costs and revenues go up apace.

The probability is that effective cost control will be exercised within incentive ranges increases as these ranges are broadened, but penalties are clearly diluted. If the end point is set at 1.3 times target costs, contractors stand to lose only about 3 percent off profit rates for exercising lax cost control. Coupled with revenue increases of from 5 to 7 percent, this may not be that unpalatable. With incentive ranges set up to 1.5 times target, profit rates are reduced only 2 percent and revenue increases range from 6 to 8 percent.

It is impossible to say at precisely what point incentive contracts become irrelevant or even perverse. At the end point of the range they must operate as either cost-plus contracts or fixed price agreements subject to renegotiation because of scope changes. Long before that end point, incentives weaken. By common agreement, ranges must be fairly narrow to exert effective pressures.[5] This in turn requires "tight" cost estimates.

What is required for a tight cost estimate is only somewhat less restrictive than what is needed for fixed price agreements. According to the Theodore Barry report, incentive contracting of large "work packages" on utility projects requires that 60 to 70 percent of total project engineering be completed and that 80 to 100 percent of the engineering for the package be already done before asking for bids.[6] Furthermore, of course, these initial specifications must not be subject to major revision.

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[5]Scherer, *Weapons Acquisitions*; also Merrow, Chappel, and Worthing note ineffectiveness of incentive contracting in defense R&D projects where targets cannot reasonably be set.
[6]Theodore Barry and Associates, *Organizational Trends*, p. VI-2.

Escalation Clauses

Changes or fuzzy definitions of the scope of work are the major source of contracting difficulty. Another source is the contractor's own uncertainty about his input costs. However, this uncertainty can be reduced substantially by contract provisions that escalate job prices along with inflation.

Escalation clauses are varied in type, though, and their special purposes and effects merit careful consideration. Escalator clauses should relieve the contractor of uncertainty about the cost influences he cannot control, while leaving him with as much incentive as possible to minimize the influences he can control.

In addition to meeting this primary purpose, escalator clauses must satisfy two secondary criteria. They should hold the costs of evaluating and monitoring inflation adjustments to tolerable levels and should enable the purchasing party, which must bear the risks of inflation, to make intelligent estimates of the eventual contract price.

The essential characteristic of any escalator clause is the index chosen. "Third-party" indices, such as those available on local wages from the Bureau of Labor Statistics, show trends in wage or price series outside the job itself. Use of third-party indices maintains maximum incentives for cost control, since the eventual price is governed by a portrait of inflation not subject to control by the contractor.

"Internal" indices include a contractor's actual wage rates or material costs. Such indices minimize the contractor's initial uncertainty about how much it will cost him to do a job. However, they leave him with less incentive to bargain vigorously in obtaining his labor and supplies, since changes in rates get "passed through" to the purchaser. Also, they may promote adjustments in the mix of personnel to produce favorable escalation results.[7]

Third-party indices are clearly preferable in terms of secondary criteria. When a purchaser offers a job with the provision that adjustments are to be made only on the basis of some published cost series, several advantages are obtained. First, all bids for the job can be evaluated through a consistent examination of bid price and probable work quality, since inflation adjustments will be the same for all of them. Second, the history of the published series offers the purchaser a means of guessing intelligently about how his future costs will move. Last, actual adjustment of the contract price can be accomplished in a relatively straightforward fashion without detailed auditing of the contractor's own cost data. Because they offer these advantages as well as promoting efficiency, third-party escalation indices are always desirable if they can remove a sufficient degree of contractor uncertainty. The key here is whether a published series can be found that depicts the cost environment the contractor expects to face. Construction cost series often move at variance with overall inflation as we saw in Chapter Two. However, differences among construction cost series, by type or region, were generally more modest. Only the parties to a bargain can determine whether past movements in the local costs of relevant items have been captured adequately by such series as the BLS wage index, Department of Commerce construction cost series, or the Handy-Whitman regional utility cost index. Modest differences should be tolerated, though. One aspect of efficiency to be preserved is the contractor's ability to hold his own costs down to levels common in his industry.

Once the index has been chosen, other escalator choices are more straightforward. The base cost should include only items actually subject to inflationary influences, and the period of escalation should match the period of uncertainty from the bid submission until the actual expenditure of funds.

Escalator clauses can be applied to fixed price contracts, as they often are in the case of standard equipment items, or they can be used in conjunction with incentive arrangements for construction work. In both cases, they only remove the portion of uncertainty due to inflation. Uncertainty due to ill-defined project scope still requires some form of cost-plus contracts.

Cost-Plus Contracts

Under cost-plus contracts, a contractor is paid the actual, auditable amount of money he spends to perform a job plus some fee, usually a proportion of costs, to cover general overhead and profit. Cost-plus contracts are used because they minimize the costs of holding market-type auctions where these would be useless in any case. When a job cannot be given engineering definition adequate for pricing, cost-plus offers can be evaluated on the basis of expected performance. During a job, if change orders must be repeatedly incorporated, cost-plus contracts provide an agreed-upon mechanism for doing so promptly.

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[7] J. Roman, "Controlling Escalation in Long Term Contracts," *Public Utilities Fortnightly*, January 31, 1980.

Under a cost-plus contract, the larger the amount of funds expended the more in both total revenues and (usually) profit a contractor makes. It is clear that ordinary contract incentives cannot work to assure efficiency in such circumstances. Two sorts of incentives are counted upon. Under cost-plus contracts, the purchaser can maintain a high degree of supervision over a job; he may stop or redirect work that is seen as wasteful. In addition, the contractor himself can seek to perform efficiently as a means of obtaining future business; he knows that inefficiency could hurt his chances.

These two incentives, supervision and the desire for future "employment," are similar in nature to the incentives that prevail within business organizations. Thus, though cost-plus contracts bring together the specialized skills of independent parties, they require many of the same tools and practices by which companies maintain intraorganization performance.

The nature of cost-plus contracting is one important link between contracts and project management. Another link was latent in some of our earlier discussion. The possibility of fixed price or incentive contracts may require breaking up a project into adequately defined jobs. This possibility in turn depends on the way in which the overall project is managed.

D. PROJECT MANAGEMENT

Project management refers to the way an overall construction job is organized and carried forward. A project management plan specifies the responsibilities of each participating company, the contractual relationships that will exist between these companies, and the systems for information and control that will enable the overall project managers to guide the complex activities of many companies. A project management plan can be judged within the terms already outlined: the incentives it maintains for promoting efficiency. Market-type incentives are enhanced when it is possible to write enforceable contracts, for at least major portions of a project, that penalize inefficient performance. Internal organization incentives are enhanced when superiors are well informed on the performance of subordinates and can control their activities.

No project management structure achieves all of these objectives uniformly nor relies exclusively upon any one sort of incentive. The various approaches to project management seek to place the most effective incentives at various points in the organizational chain.

Types of Project Management

According to a recent report by Theodore Barry and Associates (TBA), there are five basic ways of structuring major power projects.[8] They are:

- Design-Build
- Outside Project Management
- General Contractor
- Prime Specialty Contractor
- In-House Construction

The design-build structure is the traditional one. A utility contracts with one business that combines the functions of engineering design and management of the construction activity (though much of the construction work may be performed by subcontractors). Lags and confusion in the transmission of information between engineers and construction planners are thus minimized.

This structure preserves the form of the old fixed price arrangements, but not their incentives. Fixed price contracts can no longer be written for a major power project. Design-build companies operate under cost-plus agreements, but the utility still has no intimate involvement with the construction activity. Market incentives for efficiency have been removed. The effectiveness of nonmarket incentives hinges on how well the utility can keep itself informed about the project. The design-build structure was still being used in almost one-third of the projects surveyed for the Barry report.

Under the outside project management structure, a utility hires an independent company to select, coordinate, and manage all essential project activities including the design work. However, major contracts may be negotiated between the utility and individual contractors.

Under this structure, a utility is slightly more involved with construction activity. Most contracts between the utility and major contractors still have to be written as cost-plus, however, because they cannot be divided into adequately defined jobs. Since the utility has hired an outside manager, its ability to

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[8] Theodore Barry and Associates, *Organizational Trends*.

monitor and control contractor performance is partly dependent on the conduct of this manager. The utility itself does not acquire the staff or capabilities for major project management. This management structure was being used in only 1 of the 39 projects surveyed by TBA.

Under the third approach, a general contractor is hired by the utility to manage construction, but the utility also hires an architect/engineer separately and must coordinate activities between the design and construction activities. This structure requires additional staff within the utility but can bring benefits. The utility acquires familiarity with the way designs are translated into construction plans and can alter schedules and plans. Within the construction activity itself, though, the general contractor is still responsible. The contract between the utility and its general contractor must be cost-plus, and most subcontractors' are too. More than one-third of the companies surveyed by TBA used this management structure.

The fourth structure, the prime specialty contractor, attempts to improve market incentives by transferring to the utility formidable responsibilities. The utility hires an A&E company that prepares plans for the facility. Based on these designs, the utility signs contracts for "work packages" with specialty contractors. The work packages are generally specific enough to be let through fixed price or effective incentive contracts. Even where contracts are cost-plus, the utility is directly engaged at a fairly intimate level in project work. It should be well informed on the processes and performance of various contractors. The level of utility involvement is emphasized by the fact that it may require from 30 to 50 separate work packages to complete a coal plant and up to 70 to finish a nuclear plant.[9]

Utilities must have large construction staffs, with experience acquired over several projects, to use the prime specialty approach. In addition, there may be time lost as the A&E's plans are transformed by utility staff into biddable work packages. Of the projects surveyed by TBA, more than one-third were using the prime specialty contractor approach. However, only one of these was a nuclear project. Nuclear projects may still be too difficult to define adequately for competitive bids, though several of the surveyed companies said that they intended to try this approach in new plants.

The fifth structure, in-house construction, requires a utility to conduct all phases of a project, except design, with its own work force. This structure obviously places all reliance on internal organizational incentives. In-house construction might be preferred in many cases where market incentives are unworkable, but it runs up against scale and specialization considerations. Few utilities maintain ongoing construction programs of sufficient size to keep appropriate skills on board. Especially important are the design skills in fields such as nuclear safety, where changes are rapid. In-house construction was used in only 2 of the 39 projects surveyed by Barry.

In sum, only one of the five management structures enables the utility to rely much on market incentives in its own contracting, prime specialty contracting. The utility generally needs to sign cost-plus agreements for most of the work in the first three structures. In all of the arrangements reviewed, major reliance must be placed on nonmarket incentives. These in turn impose a number of requirements on utilities.

Utility Requirements

Though potentially rewarding, each new management structure increases the demands upon utilities' internal capabilities. Significantly, the structure that seeks maximum market incentives also demands a high level of performance by utility staff. The ability of a utility to perform its own responsibilities well and to create proper incentives for contractor performance depends on its capacity for control and information. Utilities can exert control over those activities where their own staff are involved, as planners, supervisors, monitors, and so forth. Table 26 summarizes the activities in which, according to the TBA report, utilities are now involved. It shows the proportion of functions, within each major type, in which utilities participate under the three most common management structures.

The first type of activity, project management, includes such functions as general project planning, project cost control, and schedule monitoring. As noted in the TBA report, what is most striking is that this activity now requires very heavy utility involvement, even under the apparently passive design-build structure. The level of involvement is much higher, however, under the prime specialty approach to project management, with participation added in, for instance, field plan development and long lead-time procurement.

[9] Theodore Barry and Associates, *Organizational Trends*, p. VII-2.

The second type of activity, design work, shows generally lower levels of utility involvement, reflecting the continued primacy of the A&E company in design. However, here again the prime specialty approach adds responsibility in, for example, component and materials specification, bid evaluation, and design changes.

TABLE 26
PROPORTION OF FUNCTIONAL ACTIVITIES ENGAGED IN BY UTILITIES UNDER ALTERNATIVE MANAGEMENT STRUCTURES
(Percent of Total Activities under Each Type in Which Most Firms Participate)

Type of Activity	Design-Build	General Contractor	Prime Specialty
Project Management Responsibilities	62%	60%	88%
Project Design Functions	43	47	70
Project Construction Functions	24	47	81

Source: Theodore Barry and Associates, *Organizational Trends*

The project construction activity includes such functions as contract administration, rework control, schedule control, and field purchasing, critical from a cost standpoint. This activity shows the sharpest differences among the various management structures, with the prime specialty approach requiring utilities to get involved in about 81 percent of its functions. Recall that the essential purpose of the prime specialty structure is to arrive at work packages, suitable detailed to be let on a fixed price basis. To take advantage of market efficiency, however, the utility must extend its internal capabilities far down the chain of operational responsibilities.

Improved capacity of utilities to control projects is clearly purchased at some cost. Utilities' internal construction staffs have grown; what is more, if experienced staff are to support more aggressive management approaches, temporary underutilization may be necessary. Table 27 illustrates this. Consolidated Edison has been active in exploring new ways to control major projects. Its internal staff for planning and managing major construction activities grew to 670 in the peak-spending year of 1973; it declined only very slowly as spending dropped much more rapidly.

The levels of Consolidated Edison's construction staff are high, even given the utility's size. By contrast, until recently, Virginia Electric Power Company has had a staff of fewer than 50 for annual construction budgets in the $250 to $350 million range.[10]

TABLE 27
CAPITAL SPENDING AND CONSTRUCTION STAFF AT CONSOLIDATED EDISON

Year	Capital Spending ($ Millions)	Construction Staff
1971	$358	449
1972	396	527
1973	407	670
1974	393	638
1975	178	625
1976	132	600

Source: A. D. Little Management Audit.

[10]A. D. Little Management Audit of Virginia Electric Power Company, on file at the National Regulatory Research Institute, Columbus, Ohio.

However, the absolute levels of staff are not at issue; Consolidated Edison pursues a more active role in its major projects and has been willing to incur more internal staff costs to do so. (On major projects, VEPCO must let out about 80 percent of contracts on a cost-plus basis.[11]) The question is whether staff should be reduced as spending is. The A. D. Little audit of Consolidated Edison was skeptical that staff could not have been cut more in line with their dollar-denominated responsibilities. On the other hand, having experienced management staff could well pay off. At an assumed average annual cost, including overhead, of $35,000 per staff/year, Consolidated Edison's failure to reduce staff proportionally with spending might cost the utility about $1.6 million per year. That is less than .2 of a percent of a nuclear power plant's cost and from 2 to 5 percent of what we estimated as a "remediable" portion of nuclear plant overruns.[12] Whether incurring these additional staff costs pays depends on how soon a new project is expected to begin, and of course on success in restraining project costs; but the opportunity for large savings is there. Some utilities have been specifically criticized for failing to boost internal staff as project responsibilities increased.[13]

Improved information systems are the other major requirement for enhanced utility control over major projects. Systems for monitoring cost and schedules are inadequate or could stand significant improvement in many utilities.[14] The TBA report cited this as an area in which utilities were themselves seeking improvement.

Information is related to organizational incentives by two goals. Information on construction cost and work progress is intended to help managers redirect work, alter schedules or financing, or otherwise adjust their project plans on the basis of current experience. Equally important, information allows utilities to form reasoned judgments on how well their contractors are performing. This could be an effective spur for efficient performance even under cost-plus contracts.

It appears that present information systems may be closer to meeting the first goal than the second. Experienced utilities are well along in the development of sophisticated systems for monitoring project schedules and are also improving cost monitoring. These systems tell a utility what is happening but do not necessarily provide a basis for evaluating why. Performance evaluation requires both data on work force productivity and benchmarks for judging it. Utilities are far from having satisfactory performance evaluation systems. Developing them may require more resources, more industry wide experience, or according to one source, reform of the FERC accounts to facilitate uniform productivity accounting.[15]

Other Management Improvements

Utilities might also take a number of specific steps to reduce costs, regardless of the overall management or contracting systems they use. Labor compensation is of course a target for major improvement. Work-sampling techniques, by which craftsmen are monitored on a random basis to determine utilization, were strongly urged in Booz-Allen's audit of the Shoreham plant.[16]

A&E charges are contracted for on a cost-plus basis. This is inevitable given the difficulty in defining the "scope" of A&E work, and at one time did not cause apprehension, since these charges made up a predictably small portion of project costs. In recent nuclear plants, that has changed. At $46 million, A&E charges represented more than 7 percent of the eventual cost of the Davis-Besse nuclear unit and were one of the most rapidly escalating items.[17]

Since there is no alternative to cost-plus contracting for design work, closer scrutiny of bids and billings is warranted. According to one expert, significant sums could be saved in design contracting by assuring that cost definitions are consistent and reasonable, and by paying close attention to the variations in salary and other costs among bidders.[18]

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[11] Ibid.
[12] See page 26
[13] Touche Ross Management Audit of Iowa Electric Light and Power, on file at the National Regulatory Research Institute, Columbus, Ohio. One way to achieve improved project management capabilities while economizing on staff build up is for several utilities to set up a joint management capability; see "New NW Services Firm Won't Bar A-Es, With Control Design Construction," *Electrical Week*, July 21, 1980.
[14] According to management audits of, for instance, Vermont Public Service Company, Pacific Power and Light, Detroit Edison, Alabama Power and Light, and Central Illinois Public Service Company, on file at the National Regulatory Research Institute, Columbus, Ohio.
[15] Telephone conversation with Lou Perl, National Economic Research Associates, May 30, 1980.
[16] Booz-Allen, "... study of Long Island Lighting Company."
[17] C. Basset, "The High Cost of Nuclear Power Plants," *Public Utilities Fortnightly*, April 27, 1978.
[18] Warren W. Gartman, "Savings From the Inside through Technical Services Contracting," *Public Utilities Fortnightly*, August 2, 1979.

Project financing is another area receiving attention. Since funds used during construction are coming to represent a much higher portion of ultimate project costs, any efficiencies achievable here would obviously pay off. Moreover, because of the much changed interest rate environment of recent years, it should not be surprising if old financing methods and rules were found to need revision. One recent discussion focused on ways of minimizing average costs of capital when interest coverage is a primary consideration.[19] The author estimated that substantial savings might be made by utilities by objectively reconsidering and adjusting their debt-equity ratios.

One frequent criticism in several audits of utility management was a lack of coordination between load and facility forecasters and the financial planners. Improving this coordination through modern capital budgeting practices may prove an essential goal for utilities in today's less certain economic environment.

Concern about utilities' financing plans recently led the New York Public Service Commission to require companies to submit their financing plans for facilities needed over the next 15 years.[20] The commission will review these plans' debt-equity relationships, short- and long-term bond mixes, and their contingency on circumstance and credit ratings.

Mention of the NYPSC's financing review is an appropriate place to close this discussion, for we have been presenting an "over the shoulder" look at the way utilities have been trying to deal with capital cost problems. The failures in this record are a legitimate target for criticism by regulators. The successes, or innovative techniques intended to achieve success, should be the subject of regulators' attention, and possibly, recommendation to utilities that are not voluntarily initiating them. We now turn more explicitly to regulators' choices.

E. REGULATORY OPTIONS

Very simply, regulators want to remove the inflationary tendencies that lie within their control or that may arise from a lack of cost discipline on the part of the companies they regulate. Where there are limits to the success that can be achieved, these limits need to be recognized early. Decisions on new plant construction in particular need to be made with a candid appraisal of ultimate costs.

This section concludes the discussion by reiterating some points made earlier with respect to utilities' own cost control options, in light of regulators' responsibilities. In addition, it presents some policy options that regulators might themselves use to respond to the construction cost problem.

Ratemaking Review of Current Projects

When a new generation facility is submitted for inclusion in the rate base, a number of ratemaking issues are raised. From a cost control standpoint, the most important is whether any portion of the cost of the facility shall be disallowed as unnecessary or unreasonable.

That only reasonably incurred costs should be allowed in the rate base is well established in principle but less certain in its application. Utility commissions are reluctant to disallow lawfully incurred costs as long as the utility, in adding plant, appears to be acting in a good faith effort to provide for the public's power needs.

Recent plant cost trends have raised a new kind of issue in rate base decisions: not whether the facility itself was necessary, but whether it was constructed in a reasonably efficient manner. This decision must be made in light of at least two influences: short-term effects on ratepayers, and longer term effects on utilities' investment incentives.

The principle of "reasonable" cost control clearly can support a range of interpretations, and hence numerical results, in any given rate case. This range has two basic aspects, toughness and accuracy. "Toughness", of course, means the severity with which regulators treat what they regard as questionable cost incurrences. For instance, in the case of the Salem plants, two different levels of cost improvements were identified (labeled "hard" and "soft"), corresponding to two different levels of management performance assumed as reasonable.[21] A third level was implicitly chosen by the New Jersey regulators who refused to second-guess the utility's actions and allowed all of Salem's costs.

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[19] J. Abel, "Capitalization Management: A Quantitative Approach to Financial Health," *Public Utilities Fortnightly*, May 10, 1979.
[20] "New York PSC Initiates Formal Investigation to Determine Ways to Reduce Construction Financing Costs for Electric and Gas Utilities," *NARUC Bulletin* no. 2 (1980).
[21] See page 23 above.

Plainly, applying the tougher standard will bring short-term benefits to ratepayers. Whether it creates positive effects on future investment incentives depends on the accuracy with which regulators can identify what were, to the project's builders, truly preventable cost increases.

If regulators identify those cost increases that project sponsors themselves know to be the result of lax management, then positive effects can flow all around. In future projects, sponsors will have the added incentive of knowing that unnecessary costs may be disallowed. In a very rough way, tough but precisely targeted allowance standards would operate like an effective incentive clause by penalizing profits for preventably bad decisions.

Just as effective incentive contracts must operate on cost increases controllable by companies, so too cost review must be able to identify bad decisions. If these cannot be identified, tougher disallowance decisions may bring harm. For example, consider a major power plant that has an "unnecessary" 10 percent element in its final costs. Suppose regulators find 10 percent of a project's costs unreasonable and disallow them. If the disallowed 10 percent does not generally match up with the 10 percent that project managers know was a result of their own laxity, and this inability to find real wastage is expected to continue, what behavior should be expected? Utility planners cannot avoid disallowance, since regulators cannot spot the real waste. Rather, they expect an arbitrary amount to be deducted whatever they do. So companies might, under these conditions, devote more attention to making sure they can absorb this loss (possibly by overstating cost or return requirements) than to controlling project costs.

This reasoning should qualify, but by no means cancel, interest in tougher reviews of cost increases. Several trends are increasing the "accuracy" with which unnecessary cost incurrences can be identified. These trends include expanded experience with both nuclear units and post-Clean Air Act coal plants, accumulation of broader data on construction costs and productivity, and enhanced expertise of companies that build, audit, or own plants. Experience, data, and expertise suggest a number of areas of frequent managerial deficiency:

- Overall Management Structure
- Cost and Schedule Monitoring
- Rework Management
- Labor Productivity
- Materials Management

Judgments on management structure should take into account the benefits of more active practices, but should also recognize that these require a company to increase its responsibilities steadily over several projects. Cost and schedule monitoring are areas in which acceptable practices are important and more easily developed management tools.

Judgments on productivity performance must recognize the special difficulties of nuclear construction. Nevertheless, data on different nuclear plants are becoming available in sufficient volume to allow comparisons and some judgments to be made.

Most judgments on power plant costs will be based on project management audits, prepared by companies with experience reviewing this particular type of construction. If experience with general management audits of utilities is a guide, these project audits will be more useful the earlier that a limited number of specific questions and areas of investigation can be agreed upon between auditor and regulators.[22] The results of past audits should be used to focus the inquiry.

Policies for Controlling New Plant Costs

The criteria applicable to reviews of current construction can also be applied, with considerably more freedom, to new plant proposals. The standards of acceptable management practice in utility construction are being rapidly upgraded. Higher standards can be applied to new plants, moreover, without the inequity possible when such standards are used retrospectively. In the case of new plants, the major areas for scrutiny appear to be:

- Management Structure
- Contracting Practices
- Cost/Schedule/Productivity Monitoring
- Financing Plans and Contingencies
- A&E Contracting Terms

[22] J. R. Fako, "A Survey of Management Audits in the Electric Utility Industry," (Pittsburgh: Public Utilities Services, n.d.)

The review of management structure must, as before, weigh the benefits of more active utility involvement with the experience required. Contracting practices partially depend on feasible management structure: major use of fixed price or incentive contracts requires the prime specialty contractor approach, favored by businesses with large in-house construction staff. However, within this limit, maximum reliance on these contract types should still be sought. Contract escalation terms should also be consistent with the objectives of relieving the contractor of uncertainty but not of incentives for controlling costs.

The more cost-plus contracts are used, the better the informational tools available to utility management must be. Systems for monitoring progress by task, and cost by task, time, and budget are mandatory; so, difficult though it may be, is an effort to monitor work force productivity in terms permitting evaluation. Unlike staff, information systems can be transferred readily among projects and businesses. Smaller, less experienced companies should thus be able to apply, and should be expected to use, the most current system for monitoring project expenditures.

Financing plans and A&E charges are two areas in which practices are now being revised or rethought. Though acceptable standards are not easily specified, these areas merit significant attention, given their current importance in project costs.

Regulatory Information and Incentive Systems

Regulators stand in somewhat the same position relative to utilities that propose plants as utilities stand relative to their own contractors. Regulators initially must judge, then monitor, and eventually evaluate the efficiency of the utilities' plant expenditures. Meanwhile, regulators would like the utility to have as strong an incentive as possible to seek efficiency for itself.

Looked at this way, regulators have two kinds of approaches to promote cost control during the actual construction of a plant, analogous to the ways in which a utility seeks to control its own costs. The first is by obtaining and maintaining detailed and timely data on the costs of the project as it is being built. As under consideration in California, a major project monitoring system would have several benefits.[23] It would let utilities know their performance was being gauged and evaluated on a current basis; it would put regulators in a much better position to audit projects when they were rate base candidates; and it would enable state energy planners to make decisions on a variety of issues—new plant approvals, rate structure, and alternative fuels policies—on the basis of current data on the costs of providing new power.

Those are essentially the kind of incentives and decisions sought by managers within an organization. In power projects, the main purpose of improved information is to enhance the control of the commission over the project by keeping in touch with its progress. Whether it achieves this purpose depends on whether or not the information relates to decisions the commission will actually make, and whether the commission is staffed adequately to use the information. Such monitoring systems must thus be viewed in tandem with the capabilities of regulatory bodies.

A different and more market like approach was taken by the Federal Energy Regulatory Commission in setting the tariff for the proposed Alaska Natural Gas Pipeline System. Under FERC's incentive rate-of-return concept, the pipeline profitability will depend on how close actual costs match estimated costs. Final project costs will be deflated into 1980 dollars and compared to a final project estimate to be offered in that year. If they are equal, a return on equity of 17.5 percent will be earned, not necessarily a high rate given the project risks and the superb cost performance assumed. Overruns would be penalized by reducing allowable equity returns (and underruns rewarded by boosting it).

This same incentive return approach might be applied to new utility plants. A final estimate of plant costs could be requested before final approval of the build decision. Construction would proceed with the understanding that when it is finished, the rate of return allowed (either on the whole rate base, or the plant's portion of it) will depend on how closely actual costs match the estimate.

Incentive rate-of-return rules work like incentive contracts: they can be effective only if the range over which profit penalties are significantly reduced corresponds to the range over which project managers really will be able to control costs. Since the center point of the range is the cost estimate submitted by the utility, this condition pivots on whether or not project costs can be estimated with some accuracy. One other condition must hold: There must be an incentive for the utility to submit a reasonable cost

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[23] Telephone conversation with Ronald Knecht, staff, California Public Utilities Commission, July 9, 1980. Several other commissions, including New York's, have or are trying such information systems.

estimate (similar to the bidding incentive in ordinary contracts). In the case of the Alaska gas line, this incentive was supplied by regulators' reluctance to approve the project unless it appeared to be economically beneficial. If regulators' decisions are not sensitive to costs, the estimate might be inflated to improve eventual returns, and the incentive approach would be unworkable.

It is quite probable that utilities can make reasonable forecasts of the costs of many coal-fired units with two provisos: the indexing of cost estimates by relevant inflation rates and the contingency of estimates on the environmental rules to be applied. Since both escalation clauses and a limited number of contingencies can be readily incorporated in an incentive return standard, coal plants may be good candidates for this approach.

It is much less probable that future nuclear plants could be built under incentive return agreements (unless design questions are resolved). As we have seen, nuclear costs have risen far more than inflation; the excess is less attributable to specific regulations than to an unpredictable process of constant regulatory revision.

Finally, if the incentive return is to be applied only to the portion of the rate base that the plant represents, an overhaul in utilities' accounting systems might be necessary to segment outlays properly. This would not be necessary if the overrun is to affect the overall rate of return. However, if the overall return is to be the incentive variable, a broader view of utility performance may also be more appropriate.[24]

Cost Realism

Many decisions broader than those affecting individual power plants are also made by regulators. Most such decisions are vitally sensitive to the prospective costs of generating electricity and need to be made on the basis of a candid appraisal of these costs.

As Chapter Two concluded, capital costs for both nuclear and coal-fired plants are climbing at rates substantially higher than general or sectoral input inflation. Table 28 summarizes the probable results of this trend, according to several sources. It shows alternative estimates of the unit cost of new plants ready for operation from the mid 1980s to early 1990s.

There is increasing agreement on the trend of coal plant costs. These costs will reach at least the \$600–\$700 per kilowatt range, in 1979, shown by most of the estimates in Table 28. The highest of the estimates, those by Komanoff, may be more realistic. His estimates include the most detailed specification of the equipment needed for compliance with the 1977 Clean Air Act Amendments and other current environmental rules. The lower end of the range shown in Table 28, \$780/kW, is approximately the cost of equipment and IDC increases envisioned by Komanoff in the 1980s; the higher figure, \$794/kW, is the result of his statistical projection.

TABLE 28
ESTIMATES OF NEW COAL AND NUCLEAR PLANT COSTS*

Source	Year of Operation	Nuclear Cost (1979 \$/kW)	Coal Cost (1979 \$/kW)
Sargent & Lundy[a]	1990	\$973	\$670–745
Komanoff[b]	1988	1374	780–794
Ebasco[c]	1990–92	800–865	565–663
Gibbs and Hill[d]	1990–92	996	720
RFF[e]	1985	838	564–680

* Adjusted from original sources to remove post-1979 inflation and include only "real" interest during construction of 3.5%. Note that even "constant" dollar costs will increase if construction costs continue moving up more rapidly than prices.

Sources: [a] R. Bergstrom and W. Brandstrom, "Trends in Electric Generating Costs," Sargent & Lundy Engineers (General paper presented before the WATT Conference, Knoxville, Tennessee, February 1979).
[b] C. Komanoff, "Cost Escalation."
[c] L. Reichle, "The Economics of Nuclear versus Coal," (Ebasco Services, a paper presented before the Richmond Society of Financial Analysts, Richmond, Va., October 1979).
[d] "Economic Comparison of Coal and Nuclear Electric Power Generation," (N.Y.: Gibbs and Hill, Inc., January 1980).
[e] S. Schurr, et. al. *Energy in America's Future: The Choices Before Us*, Resources for the Future (Baltimore: Johns Hopkins Press, 1979).

[24] Such as those based on Total Factor Productivity; see John W. Kendrick, "Efficiency Incentives and Cost Factors in Public Utility Automatic Revenue Adjustment Clauses," *The Bell Journal of Economics*, Spring, 1975, p. 299–313.

Several of the other estimates of coal costs were made either prior to the 1977 act or before the regulations that flowed from it. The major differences in ranges shown generally are attributable to assumptions about the necessity of scrubbers with various types of coal.

There is less agreement about nuclear costs. Four of the estimates fall in the $800 to $1,000/kW range. These assume a stabilization of safety criteria and design standards at something like their present state. The highest estimate, again by Komanoff, assumes that NRC rules will continue to evolve, in a very costly way, as plant experience is gained.

After the Three Mile Island accident, it is unlikely that either of these scenarios will unfold, at least in the short term.[25] Most nuclear-owning utilities are primarily concerned now with the cost of retrofitting old plants rather than building new ones. The changes required by NUREG 0660, issued by the Nuclear Regulatory Commission in the wake of TMI, will cost utilities about $25 million per plant according to the NRC. Industry estimates put the costs much higher, at from $37 million to $204 million per plant and non-government observers agree that the NRC estimate is probably low.[26] The new costs to be incurred on old coal plants are also high. The highest are likely to occur where oil-fired units must be converted to coal while meeting more stringent environmental rules. According to one set of estimates, boiler modification and precipitator upgrade alone will add from $100 to $300 per kilowatt, depending on site and difficulty, while scrubber installation costs another $150/kw.[27] Federal assistance for utilities in bearing these costs is now under legislative consideration. These retrofitting costs are of the same magnitude as the cost of a new plant not so long ago. Regulators' attention might focus usefully on how these retrofit costs are incurred, and some of the criteria applicable to new plant decisions could be applied there helpfully.

Other Institutional Remedies

The unpleasantness of the choices facing state utility regulators has renewed interest in what help might be afforded by other government mechanisms. The interest is understandable, since much of the unpleasantness derives from mandates issued by other agencies. Problems also spring from the increasing participation of these agencies in utilities' planning processes as well as utility commissions' hearings on plants. We cannot analyze these remedies here, but we can review a few of them quickly.

The federal standardization of nuclear design requirements would bring significant cost relief. As noted in Chapter Two, design standardization could not only halt nuclear's real cost growth but perhaps reverse it, as A&E's developed better ways of meeting stable criteria.

That is improbable, however, and not only because of the controversy about Three Mile Island. Stabilizing nuclear design standards really requires solution of major difficulties at two levels. First, we would have to arrive at a social consensus about what levels of risk from nuclear plants are acceptable. Second, this consensus would have to be translated into design practices that satisfied it. We are far from arriving at the social consensus, and given the very low probability but high potential harm of nuclear accidents, translating these into safe design standards would be difficult in the extreme.

Logically similar is the case for new mechanisms to expedite power plant siting decisions. Here the potential benefits are less but more achievable. Siting delays are not a major contributor to real plant inflation (that is, adjusted for input inflation), since they precede major construction expenditures. However, coordination of various state, local, and federal siting decisions would bring some order and efficiency to the planning process. According to one state regulator, this would require, among other things, the designation of a federal "lead agency" for coal plant siting approval.[28]

Something along the lines of the War Renegotiation Board, used to hold down defense procurement costs, might also be considered. The board conducted after-the-fact reviews of the performance of contractors who had cost-plus or incentive contracts with the government. It was empowered to eliminate excessive profits, but ideally, would also reward efficient contractors by allowing higher than average profits.

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[25] At the very least, TMI will add two years to the completion periods of plants now under way, according to nuclear cost expert Irwin Bupp; see "Midwest Nuclear Plant in the Works 13 Years Keeps Facing Delays," *Wall Street Journal*, March 4, 1980.

[26] *Inside NRC*, February 25, 1980; also private correspondence with Charles Komanoff, August 30, 1980.

[27] Martin Wagner, "Staff Paper on Displacing Oil Power Plants with Coal" (Internal Staff Memorandum, Energy Policy Branch, Environmental Protection Agency, December 21, 1979).

[28] J. Williams, "Power Plant Siting Reform: Panacea or Purge," *Public Utilities Fortnightly*, November 9, 1978.

Though supposed to encourage efficiency as well as eliminate windfalls, the Renegotiation Board generally had disappointing results. One investigator found that the board, by concentrating on rates of return rather than performance during World War II, reenforced cost-plus attitudes and may have prompted excessive costs.[29] Frederic Scherer, looking at some later case studies, found that the board's existence simply did not count for much in influencing contractor's decisions.[30] On the other hand, the vehemence of contractors' opposition to the board may be taken as evidence that it was putting on some pressure, even it not of the intended kind on these companies' activities.

The key problem, as Scherer noted, was that unless the board could make discriminating judgments about efficiency, it would not promote cost consciousness. Any mechanism set up by utilities or regulators to evaluate contractors confronts the same formidable challenge of matching capabilities with responsibilities.

Still, the idea of consolidating project data, experience, and evaluations of major contractors has an appeal. If the results of this consolidation were merely advisory, rather than decisive, capabilities would need to be less extensive while benefits could be real. Among useful tasks that could be performed are better accounting for project costs, analyses of cost variation influences, and performance grading of contractors based on multi-project experience.

A Concluding Note

Public Utility Commissions' choices in dealing with plant overruns are limited and imperfect. Some of these choices would involve commissions more intensely in one of their traditional roles: examining utilities' management practices and attempting, through scrutiny and pressure, to improve them. Other choices, most prominently the incentive return concept, would attempt to exert a more formal and predictable force for efficient management.

That the choice between these two approaches is not an either/or one should be clear, for there is an analogy here to options utilities themselves have: they can try to exert a more detailed control over construction activities, or they can provide incentives for contractor efficiency. As we saw, the ability to provide effective incentives often requires beefed-up utility capabilities for management and information. So too, automatic incentives for a utility performance may require greater participation by utility commissions in plant planning. Incentive return rules will only work, for instance, if the authorizing commission knows enough about a project before hand to judge the reasonableness of a cost estimate and the range of overrun possibilities. The various remedies outlined in this chapter should thus be regarded not as adversaries, but rather as complementary and mutually supporting choices. The magnitude of the overrun problem provides urgent justification for pursuing as many promising policies as possible.

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[29] J. P. Miller, *The Pricing of Military Procurement* (New Haven: Yale University Press, 1949).
[30] F. M. Scherer, *The Weapons Acquisition Process: Economic Incentives* (Boston: Harvard University Press, 1964).

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