

Incentive Regulation For Electric Utilities

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Electric utility price regulation in the United States has historically entailed a state regulatory commission overseeing a utility's rate structure by setting an allowed rate of return for the utility on its invested capital. Although state commissions typically have the power to disallow recovery by a utility of imprudently incurred expenses, the current regulatory system was not designed to encourage utilities to control costs. In search of ways to promote efficiency in electricity production, a number of state regulatory commissions have turned their attention from retrospective second-guessing of utility management to "incentive regulation" approaches, which condition financial rewards or penalties upon some measure of a utility's performance.

To date, approximately twenty state public utility commissions have applied some type of incentive regulation to at least one electric utility under their jurisdiction. The number of states introducing such schemes has increased rapidly in the past few years, reflecting the growth of interest among regulators.¹ Incentive regulation could lead to fundamental changes in the way electric utilities—and perhaps other firms—are regulated. This Article presents an examination and assessment of the rationale for making incentive-oriented changes in regulatory rules and procedures, the principles that should guide the construction of sound incentive mechanisms, and the practical problems that must be solved if such mechanisms are to be effective in practice.

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The authors are grateful to John Landon for supplying the material in the Appendix and to him and Jean Tirole for helpful comments. Paul Joskow acknowledges support from the Center For Advanced Study in the Behavioral Sciences and the Massachusetts Institute of Technology. The authors are responsible for all opinions expressed in this Article and any errors it may contain.

1. See, e.g., J. LANDON, *INCENTIVE REGULATION IN THE ELECTRIC UTILITY INDUSTRY* (1985); EDISON ELEC. INST., *INCENTIVE REGULATION PROGRAMS IN THE ELECTRIC UTILITY INDUSTRY* (1984); NAT'L. ASS'N OF REGULATORY UTIL. COMM'RS SUBCOMM. ON ELEC., *INCENTIVE REGULATION IN THE ELECTRIC UTILITY INDUSTRY* (1983); RESOURCE CONSULTING GROUP, INC., *INCENTIVE REGULATION IN THE ELECTRIC UTILITY INDUSTRY* (1983) (prepared for the Federal Energy Regulatory Commission).

Part I of the Article describes the institutional framework within which privately owned electric utilities (commonly called "investor owned" utilities) have been regulated in the United States for many years,² and discusses the shortcomings of this framework which are motivating interest in incentive regulation proposals. Part II describes recent theoretical work that attempts to obtain "optimal" solutions to the incentive problems created by price regulation and discusses the implications of this work for desirable reform of the regulatory process. Part III analyzes several specific incentive schemes that have either been proposed for implementation by state regulatory agencies or have actually been used by state commissions. Finally, Part IV offers our conclusions on the future role of incentive regulation, arguing in favor of a restructuring of current fuel cost incentive programs and the extension of incentive regulation to utility operation and maintenance costs.

Some will no doubt argue that the best way to increase the efficiency with which electricity is supplied is to deregulate the electric power industry, relying on competition rather than regulation. We have considered various deregulation proposals in detail elsewhere.³ The economic effects of deregulation in this industry are uncertain and political enthusiasm for radical experiments is not great. It seems reasonable to assume that commission regulation of retail sales of electricity will continue for the foreseeable future;⁴ but it also seems likely that there will be continuing interest in reforming the regulatory process to enhance the performance of electric utilities.

I. The Current Regulatory System and Its Performance

Presently, every state with investor owned utilities regulates rates via independent regulatory commissions composed of either appointed or elected members. This Part is concerned with the structure and performance of that regulatory regime.

2. Roughly 75% of retail sales of electricity in the United States are made by private firms; the rest is accounted for by municipal utilities, cooperative utilities, irrigation districts, and other state public utility districts. See P. JOSKOW & R. SCHMALENSSEE, *MARKETS FOR POWER: AN ANALYSIS OF ELECTRIC UTILITY DEREGULATION* 12 (1983). The Federal Power Marketing Agencies make some sales directly to large industrial customers under their statutory authority, 16 U.S.C. § 824i-k (1982), but they are involved primarily in the production of electricity for resale by publicly owned and privately owned utilities. For more detail, see P. JOSKOW & R. SCHMALENSSEE, *supra*, at ch. 2. This Article focuses entirely on privately owned utilities. While the basic ideas discussed here apply to public enterprises, explicit consideration of the details involved would unnecessarily complicate our analysis.

3. P. JOSKOW & R. SCHMALENSSEE, *supra* note 2.

4. Sales to large industrial customers may be an exception. See *infra* note 10.

Incentive Regulation

More than two hundred investor owned utilities, some tiny and some huge, supply electricity in the United States.⁵ Most of these companies are vertically integrated, engaging in the generation, transmission, and distribution of electricity.⁶ The typical utility historically sought to acquire sufficient generation and transmission capacity to satisfy the demand for electricity by its retail customers.⁷ Investor owned utilities usually operate under long term franchises that are either explicitly or *de facto* exclusive, so they do not face direct competition from other utilities.⁸ With no direct competition, it is generally believed that if electric utilities were free to set prices to maximize their profits, they would be able to charge retail customers monopoly prices far above current rates.⁹ In return for exclusive geographical franchises, utilities are subject to rate regulation (and other types of regulation described below) and are obliged to provide reliable service to all who demand it at the regulated prices.¹⁰

5. Class A and B electric utilities are defined by the United States Department of Energy. Class A utilities are those having an annual electric operating revenue of \$2.5 million or more; Class B utilities are those having annual electric operating revenues of between \$1 million and \$2.5 million. ENERGY INFORMATION ADMIN., STATISTICS OF PRIVATELY OWNED ELECTRIC UTILITIES, 1981 ANNUAL. (CLASSES A AND B COMPANIES) (1983). See also P. JOSKOW & R. SCHMALENSEE, *supra* note 2, at 12. The number of independent companies is smaller than the figure given in the text because several holding companies own multiple operating companies. The operating companies, however, not the holding companies, are subject to the regulation of interest here.

6. Several companies included as Class A and B electric utilities are engaged solely in the wholesale (sale for resale) generation and transmission (G&T) business. However, with very few exceptions, these wholesale G&T companies either are subsidiaries of holding companies that also have distribution company affiliates or are joint ventures of other integrated utilities. There are also some small private distribution-only utilities that buy power from other utilities. See P. JOSKOW & R. SCHMALENSEE, *supra* note 2, at 11-23.

7. In recent years utilities seeking additional generating capacity have acquired ownership interests in plants operated by other utilities. Since 1978, utilities have been required to purchase electricity produced by certain qualifying cogeneration and small power production facilities pursuant to the Public Utility Regulatory Policy Act of 1978 (PURPA), 16 U.S.C. § 824a (1982); see also 18 C.F.R. pt. 292 (1986). Some utilities may purchase a significant fraction of their requirements from these independent suppliers within the next decade. In addition, some integrated privately owned utilities are becoming interested in contracting with others to build and operate generating capacity to provide them with additional power in the future. Despite these trends, independent capacity still accounts for only about three percent of total generating capacity. EDISON ELEC. INST., STATISTICAL YEARBOOK OF THE ELECTRIC UTILITY INDUSTRY: 1984 (1986).

8. Distribution franchises last at least ten years; most are of very long duration, and some are perpetual. Franchise contests have been quite rare in recent years. See Joskow, *Mixing Regulatory and Antitrust Policies in the Electric Power Industry: The Price Squeeze and Retail Market Competition*, in ANTITRUST AND REGULATION: ESSAYS IN MEMORY OF JOHN J. MCGOWAN 178 (F. Fisher ed. 1985).

9. In some situations the demand for electricity is highly elastic because substitute fuels can be used (for space heating, for instance). Additionally, some industrial customers may have very elastic demands for electricity supplied by the local utility as a consequence of good self-generation options. Franchise exclusivity generally does not preclude a customer from generating electricity for his own use. Furthermore, PURPA requires utilities to buy electricity produced by certain qualifying cogeneration and independent power facilities. See *supra* note 7. These independent suppliers are not generally free to make retail sales to other customers, however. Thus the demand for electricity by most industrial customers and all residential customers is very inelastic—especially in the short run before stocks of plant, equipment, appliances, and housing can be replaced in response to higher electricity prices.

10. Utilities also sell electricity to one another. These "sales for resale" are called "wholesale"

A. *Regulatory Procedures*

State public utility commissions regulate the price and non-price terms and conditions of retail electricity sales.¹¹ A utility must submit to the commission, in advance of their effective date, any proposed changes in the level or structure of its existing rates as specified in its filed tariffs.¹² The commission may then either allow such changes to become effective or disallow them.¹³ The commission on its own initiative can also order the utility to change the level and structure of its rates if the commission determines that they are not consistent with state law.¹⁴ These proceedings are known as rate cases. To a first approximation, prices are fixed unless changes are approved or ordered by the commission. But some tariffs also have automatic adjustment provisions so that prices automatically move up or down as input costs change.¹⁵ In general then, what is fixed between rate cases is a formula for determining prices.

Most state commissions operate under fairly vague statutory mandates which provide that the commission is to set rates that are "just, reasonable and non-discriminatory."¹⁶ State statutes may elaborate more specific criteria as well. For example, state law may provide that facilities must be "used and useful"¹⁷ in order for their associated costs to be incorporated

transactions and are subject to regulation by the Federal Energy Regulatory Commission (FERC) under its statutory authority, 16 U.S.C. § 824a (1982). Many wholesale transactions are only loosely regulated. *See Earley, FERC Regulation of Bulk Power Coordination Transactions* (1984) (unpublished manuscript on file with the Federal Energy Regulatory Commission, Office of Regulatory Analysis). Buyers and sellers in wholesale markets often have competitive alternatives, so that market constraints are much more important potential sources of incentives there than in retail markets. Since the electricity produced for wholesale trade is generally supplied from the same facilities as electricity for retail sale, there may be market incentive effects from the wholesale market that spill over into retail markets. While this Article does not discuss wholesale electricity transactions and regulation, we note that the direction of reform in wholesale markets seems to be toward less regulation (incentive or otherwise) and more toward reliance on competition. *See, e.g., Notice of Inquiry Re: Regulation of Electricity Sales for Resale and Transmission Service, Federal Energy Regulatory Commission Docket No. RM85-17-000, 50 Fed. Reg. 23,445 (1985).*

11. This Article is not designed to provide a comprehensive review of state public utility law; it focuses on "typical" regulatory procedures. There are obviously differences from state to state, but the similarities are much more significant than the differences.

12. *See, e.g., CAL. PUB. UTIL. CODE* § 491 (West 1975); *N.Y. PUB. SERV. LAW* § 66(12) (McKinney Supp. 1986).

13. *See, e.g., CAL. PUB. UTIL. CODE* §§ 454-455 (West 1975 & Supp. 1986); *N.Y. PUB. SERV. LAW* § 66(12) (McKinney Supp. 1986).

14. *See, e.g., CAL. PUB. UTIL. CODE* §§ 728-729 (West 1975); *N.Y. PUB. SERV. LAW* § 66(5) (McKinney 1955).

15. Both the California and New York public utility statutes contain provisions permitting commission authorization of tariffs with automatic adjustment features. *See CAL. PUB. UTIL. CODE* § 457 (West 1975); *N.Y. PUB. SERV. LAW* § 66(12)(16) (McKinney 1955). Both of these states' commissions have experimented with automatic adjustment clauses based on energy or fuel prices. *See Appendix and J. LANDON, supra note 1.*

16. *See, e.g., CAL. PUB. UTIL. CODE* §§ 451, 453 (West Supp. 1986); *N.Y. PUB. SERV. LAW* § 65(1)(3) (McKinney 1955 & Supp. 1986).

17. *See, e.g., CAL. PUB. UTIL. CODE* § 1005.5(d) (West Supp. 1986); *ILL. ANN. STAT.* ch. 111½,

in rates, or specify that only costs which have been “prudently incurred”¹⁸ may be included in rates. It is our impression that state legislatures have provided more specific guidance to commissions regarding acceptable regulatory procedures in recent years.¹⁹ This is especially true with regard to fuel adjustment clauses and the treatment of the costs of generating plants under construction.²⁰ To our knowledge, no state statute permits commissions directly to fine or subsidize utilities subject to their jurisdiction. Rather, it is the methods used to determine prices that provide incentives, either good or bad, to regulated firms.

The basic principle that currently guides commission regulation of electricity rates is that prices should reflect the “cost of service.”²¹ For the utility as a whole, prices are, in theory, set so that total revenues equal total costs or, alternatively, so that the average revenue per unit of electricity sold equals the average cost of supplying it. For specific services provided by the utility (such as residential, commercial, and industrial service in different seasons and at different times of day) prices should, in theory, reflect the costs of providing the individual services. Economists argue that marginal cost should determine the prices of individual services, but regulators have historically attempted to define and employ service-specific average costs.²² Arbitrary rules for allocating common costs to individual services, along with considerations of distributional fairness and political constraints, often lead to rates for specific services that differ substantially from marginal cost.

para. 9-211 (Smith-Hurd Supp. 1986).

18. See, e.g., CAL. PUB. UTIL. CODE § 463 (West Supp. 1986) (requiring commission to disallow those expenses resulting from “error or omission” in planning, construction, or operation of utility facilities and permitting commission to find other utility expenses “unreasonable or imprudent”); N.Y. PUB. SERV. LAW § 66(12) (McKinney Supp. 1986) (allowing commission to order refund of monies collected pursuant to increased rates arising from adjustment clauses when utility was found to have exercised less than “reasonable care” in providing electrical service).

19. See, e.g., California Alternative Energy Source Financing Authority Act, CAL. PUB. RES. CODE §§ 26000-26042 (West Supp. 1985); N.Y. PUB. SERV. LAW § 66-c (McKinney Supp. 1986) (energy conservation encouraged); WIS. STAT. ANN. § 196.374 (West Supp. 1986) (fuel conservation encouraged).

20. See, e.g., ILL. ANN. STAT. ch. 111½, para. 9-213 (Smith-Hurd 1986) (Act effective Jan. 1, 1986, No. 84-617, § 9-213, 1985 Ill. Legis. Serv. 813, 890 (West)) (rate treatment of new plant facilities); CAL. PUB. UTIL. CODE § 454.8 (West Supp. 1986) (Act approved Sept. 23, 1985, ch. 926, 1985 Cal. Legis. Serv. 204-206 (West)) (rate treatment of new plant facilities); CAL. PUB. UTIL. CODE § 454.5 (West Supp. 1986) (Act approved Aug. 21, 1976, ch. 520, 1976 Cal. Stat. 1272) (respecting rate adjustments for fuel cost increases).

21. See 1 A. KAHN, THE ECONOMICS OF REGULATION 26-27 (1970).

22. If a firm produces multiple products and some of them share inputs (the same management and power plants serve both business and residential customers, for instance), the average cost of any single product is, as an economic matter, undefined. See W. BAUMOL, J. PANZAR & R. WILLIG, CONTESTABLE MARKETS AND THE THEORY OF INDUSTRY STRUCTURE ch. 4 (1982). Accountants produce product-specific average cost figures by allocating the costs of shared inputs among products in various arbitrary ways.

Commissions theoretically set rates so that both operating costs (fuel, labor, and materials) and capital costs are covered. Operating costs can be obtained directly from the utility's accounting system if rates are set on the basis of actual costs in a past "test year," or they can be estimated fairly easily if a future "test year" is employed. Capital cost is equal to depreciation plus a "fair return" on the utility's actual or estimated investment. While there was considerable debate earlier in this century as to the proper method for computing the "fair return" to which utilities are entitled,²³ most commissions now obtain this quantity by multiplying an estimate of the utility's nominal cost of capital by the depreciated original cost of its assets. This latter quantity is called the utility's "rate base." Straight-line depreciation is employed, with asset lifetimes that are to some extent arbitrary—and thus the subject of debate from time to time.

This approach to determining capital cost would, if applied exactly and continuously, give the utility a stream of earnings for each asset that has as its present value (using the cost of capital as the discount rate) the original cost of the asset.²⁴ That is, if rates are continuously adjusted according to these ratemaking formulas, the utility earns its cost of capital exactly, and the market value of the firm exactly equals its book value.²⁵ It is important to note that an infinite number of other rules for computing capital costs would yield these same results. Because depreciation rules are arbitrary, the capital cost charged at any one instant does not generally equal the true, economic cost of using the firm's capital at that instant; in other words, accounting and economic depreciation are equal only by chance.²⁶ Inflation compounds the problem.²⁷ Proposals for

23. The generally controlling case is *Federal Power Comm. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), in which the Supreme Court gave regulators considerable freedom as to the method used, as long as it resulted in earnings adequate to permit the utility to raise funds in the capital market.

24. More precisely, the theorem may be stated as follows. Suppose that an asset costs $\$K$ originally and has an arbitrary accounting lifetime of T years, and let the cost of capital be r . Annual depreciation is then $\$K/T$. Allowed earnings are r times the depreciated value of the asset at the start of each year, which is equal to $K[1-(t/T)]$ when the asset is t years old. The present value at discount rate r of depreciation plus earnings (both assumed to be received at the end of each year) is exactly K , for any cost of capital, r , and accounting lifetime, T .

25. See Myers, *The Application of Finance Theory to Public Utility Rate Cases*, 3 BELL J. ECON. & MGMT. SCI. 58, 73 (1972).

26. A simple example illustrates the difference. Suppose that the general price level and the nominal cost of building power plants are constant over time. Assume further that all power plants are as good as new for ten years after construction and then must be completely replaced at the end of that time.

Economic depreciation is based on the competitive market value of services supplied by capital assets. Since a two-year-old power plant is by assumption indistinguishable from an eight-year-old plant, both provide identical services. It follows that the competitive market values of the services they supply are also identical. The annual economic cost of capital is thus constant over the plant's lifetime in this example. The cost of capital is equal to the annual depreciation charge plus the product of the allowed rate of return and the plant's depreciated value. Since the depreciated value falls over time, it follows that economic depreciation must be increasing over the plant's lifetime if the cost of capital is

incentive regulation must take these problems into account, since only accounting costs are generally observable in practice.

In practice, regulation does not follow these simple ratemaking principles either exactly or continuously. Two important practical features of electric utility ratemaking are worth noting. First, commissions do not continuously adjust prices through time as costs change. Rates are changed only on the motion of the company or the commission and after the commission has held often lengthy hearings. Prices (or, more precisely, the provisions of filed tariffs) may remain unchanged for years as they did during the 1950's and 1960's for some utilities.²⁸ The tendency of regulated rates to adjust slowly to changes in costs is frequently referred to as "regulatory lag." Due to regulatory lag, the actual rates of return earned by electric utilities may be above or below the commission-determined fair rate of return at any instant. This important fact has been ignored in much of the theoretical literature on regulation.²⁹ Moreover, when prices

to remain constant. (In fact, the annual growth rate of depreciation is just equal to the allowed rate of return in this example.)

Under traditional cost of service principles, however, straight line depreciation would be used instead. This implies that the annual depreciation charge is constant, but the return on investment component declines over time as the depreciated value of the plant declines. Thus, the capital costs used to determine prices decline over time, rather than being constant as they should be in this example if regulated prices are to reflect the economic value of the services supplied by plants of different ages. A two-year-old plant would have a higher accounting capital cost (and thus higher regulated prices) than an eight-year-old plant, despite the fact that the competitive market value of the services provided by the two plants during any particular period is the same.

In general, straight-line depreciation is equal to economic depreciation only under very special conditions unlikely to be encountered in practice, so that accounting and economic capital costs generally differ. For general treatments of the difference between economic and accounting capital costs and of the implications of those differences, see Fisher & McGowan, *On the Misuse of Accounting Rates of Return to Infer Monopoly Profits*, 73 AM. ECON. REV. 82 (1983); Navarro, Petersen & Stauffer, *A Critical Comparison of Utility-Type Ratemaking Methodologies in Oil Pipeline Regulation*, 12 BELL J. ECON. 392 (1981); Stauffer, *The Measurement of Corporate Rates of Return: A Generalized Formulation*, 2 BELL. J. ECON. & MGMT. SCI. 434 (1971).

27. See, e.g., Streiter, *Trending the Rate Base*, PUB. UTIL. FORT., May 13, 1982, at 32. True economic capital costs at any instant depend on the current cost of new assets that could provide the same services, rather than—as in regulatory accounting—the historic cost of past investments. Inflation thus causes accounting costs to understate true costs, particularly for the exceptionally long-lived assets employed in the electric utility industry.

28. Since 1970, tariffs have been less long-lived than in earlier decades, because rapid increases in nominal costs have led utilities to apply for offsetting rate increases more frequently. See Joskow, *Inflation and Environmental Concern: Structural Change in the Process of Public Utility Price Regulation*, 17 J. L. & ECON. 291 (1974).

29. For example, the well known Averch-Johnson model assumes both that regulation continuously matches prices with costs (including a fair rate of return that is greater than the cost of capital) and (implicitly) that the commission must mechanically accept all costs the utility incurs. We have just argued that the first of these assumptions is inconsistent with reality; the next paragraph points out that the second is at best imperfectly satisfied. On the Averch-Johnson model, see Averch & Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 AM. ECON. REV. 1052 (1962). See also E. BAILEY, *ECONOMIC THEORY OF REGULATORY CONSTRAINT* 4 (1973), ("[T]he standard result [under Averch-Johnson] is that the firm has an incentive to misallocate resources by substituting capital for labor in production, and that this misallocation is strictly preferred by the firm to any padding of the rate base."); R. SCHMALENSEE, *THE CONTROL OF NATURAL MONOPOLIES* (1979); Joskow &

are fixed, utilities can increase profits by cutting costs, while there would be no such incentive if prices were continuously adjusted so that all costs incurred by a utility would be recovered at every instant.

Second, commissions are not bound to set rates that cover *all* costs incurred by regulated firms. Regulators have the authority to "disallow" both capital and operating costs that would ordinarily be included in rates if they find that the associated expenditures were imprudent or unnecessary.³⁰ In principle, a commission can disallow certain costs if it believes that the utility was inefficient because it could have obtained the corresponding services more cheaply or did not require those services at all. This feature of the current system has become quite visible in recent years in disputes about whether ratepayers or shareholders should bear the costs of nuclear plants that have turned out to be either extremely expensive or unnecessary to meet demand.³¹

In addition to setting rate levels (average price for all units sold) and rate structures (prices for specific classes of customers and different services), commissions also establish other terms and conditions of service, such as line extension requirements, billing procedures, and service quality attributes; issue certificates of convenience and necessity to allow the addition of new plant and equipment; supervise franchising and refranchising; approve mergers and acquisitions; and, sometimes, get deeply involved in supply side planning and operating issues. These non-price attributes of regulation vary much more from state to state than does the basic structure of price regulation; further, they are less central to the provision of incentives for efficient supply, since they do not directly affect utility profits as price regulation does. Accordingly, we will largely ignore non-price regulation in what follows.

B. *The Regulatory Contract*

For purposes of the discussion that follows it is useful to think of the regulatory process embodied in established regulatory procedures as a long-term "regulatory contract" between electricity customers, represented by the public utility commission, and the utility.³² This contract places

Noll, *Regulation in Theory and Practice: An Overview*, in *STUDIES IN PUBLIC REGULATION* (G. Fromm ed. 1981); and Joskow, *supra* note 28, for discussions of the Averch-Johnson model's assumptions.

30. For a discussion of the history of the prudent investment test, see NAT'L REGULATORY RESEARCH INST., *THE PRUDENT INVESTMENT TEST IN THE 1980's* iii-vii (1985).

31. See, e.g., *Consumer Office Seeks Removal of Nuclear Unit from PS Colorado Rate Base*, *ELECTRIC UTIL. WEEK*, Nov. 18, 1985, at 7; *Mo. Regulators Still Trying to Resolve Callaway-2 Cancellation Issue*, *ELECTRIC UTIL. WEEK*, Oct. 28, 1985, at 7; *California May Order Avoided-Cost Rates for Palo Verde in the Next Month*, *ELECTRIC UTIL. WEEK*, Oct. 21, 1985, at 3.

32. For a discussion of deregulation that adopts this same approach, see Shepherd, *Entry as a*

explicit and implicit obligations on both the utility and, through commission policies, its customers. In return for the long-term exclusive right to sell electricity in a particular geographical area, the utility takes on the obligation to provide a reliable supply of electricity to all who demand it and to do so at minimum cost. The regulatory commission in turn has the obligation to compensate the utility for all costs that it prudently (read efficiently) incurs to meet those obligations. If the regulatory contract did not have a compensation provision that credibly led an efficient utility to expect that it would on average recover its costs, the utility would not agree to supply service.

If the utility does not live up to its side of the bargain—for example, by incurring costs that are excessive in some sense—the commission may disallow recovery of these costs. The threat of disallowance, at least in theory, provides an incentive for the utility to make efficient production decisions. On the other side, due process requirements embodied in state law and court supervision of regulatory commissions, again at least in theory, keep the regulatory agency from “holding up” the utility by failing to compensate it fully after the fact for investments that it has made to provide service. An additional constraint on commissions is that if regulators adopt policies that do not provide a utility with adequate returns, investors will be unwilling to supply the capital necessary for new capacity, and consumers will suffer inadequate service. This constraint only applies, however, when new capacity is likely to be required in the reasonably near future. In the past few years, with excess generating capacity and slow demand growth in many areas, this constraint on commission behavior has lost much of its force. Under this stylized regulatory contract, commissions employ a cost-plus contract to set prices, provided costs pass the test of “prudence.” At least implicitly, this prudence test has both short run and long run dimensions. In the short run, the utility is expected to operate efficiently the plant and equipment that it has in place at any instant. This requires attention to both the physical performance of the equipment (using fuel efficiently, for instance) and least-cost procurement of fuel, labor, and other variable inputs. In principle at least, the short run prudence test is no different from the short run efficiency test imposed by competitive markets.

The long run dimension of the prudence test requires the utility to make efficient capital investment decisions. Not only should plant and equipment be procured at minimum cost, but the optimal types and quan-

Substitute for Regulation, 63 AM. ECON. REV. PROC. 98 (1973); see also Goldberg, *Regulation and Administered Contracts*, 7 BELL. J. ECON. 426 (1976).

tities of assets should be acquired.³³ In principle, investment decisions are prudent if they were optimal at the time they were made, given what was known by the utility at that time. Thus, if an investment decision was reasonably expected to lead to least-cost supply, considering both capital cost and expected operating cost, both the direct cost of the investment (including a fair rate of return) and the operating cost associated with utilizing it efficiently should be recovered by the utility in rates. This is true whether or not the investment turns out to have been optimal after the fact.

Ideally, this regulatory contract would simulate on average the outcomes that would emerge in an unregulated competitive market. For example, in an unregulated competitive market, prices would on average just cover the costs (including a normal return on investment) of supplying output efficiently. Suppliers would get no more and no less than the minimum cost of providing service, since competition would eliminate both excess profits (prices above cost) and inefficient production behavior.

But the pattern of departures from the average, caused by unforeseen events, differs between regulation and competition in ways that have strong implications for efficiency. This divergence is clearest in the case of capital costs.³⁴ When investment decisions regarding electric utility plant and equipment are made, there is necessarily uncertainty regarding future demand, construction and operating costs of alternative technologies, rates of technical change, and other factors. In competitive markets without long-term contracts between buyers and sellers, the return each firm actually realizes on its investments depends upon the interaction of supply and demand at each instant during the economic lives of those investments. If demand turns out to be higher than most sellers expected, for instance, prices will rise above average total cost until new capacity can be added to bring supply and demand back into long run balance. In the interim, firms that are in the market will earn short run economic rents on their past investments in capacity. On the other hand, if demand turns out to be lower than the typical firm had expected, prices will fall and most investments will yield subnormal returns for some period. If any firm, due to skill or luck, happens to build a facility that has lower costs than those of

33. The costs of a capital investment decision involve more than the costs of the assets acquired. For example, a utility might have to decide between building a coal-burning plant and an oil-burning plant. If the investment costs are the same, the decision must turn on expected fuel costs. The net costs of a bad decision would be excessive fuel costs (a variable cost), not high asset costs.

34. Electric utilities differ from most other businesses in having longer lead times between the planning, construction, and ultimate completion of a plant, longer economic lives of investments, and extremely specialized assets that cannot be shifted among final products or markets served. The consequences of these differences for contracting and transaction governance are explored in detail in P. JOSKOW & R. SCHMALENSEE, *supra* note 2; *see also supra* note 26.

its rivals, it will earn some economic rent over and above the economic costs of production. If it builds a lemon, it will not cover its economic costs.

The profit that an individual competitive firm actually earns depends both on its ability to make efficient investment decisions based on available information *and* on the actual realizations of costs, demands, and prices as market conditions change over time. At any instant, some firms will earn more than a competitive return, and others will earn less. An efficient competitive firm will expect on average to earn a normal return on its investments when they are made, and in the long run the average firm will earn a competitive rate of return. Thus, without any long term contracts, competition provides incentives for firms to make efficient investment decisions *ex ante*. The typical firm that makes efficient investment decisions will expect to earn a competitive return and, on average, it will. But at any point in time a specific firm, even if it has made investment decisions that were efficient *ex ante*, may be earning more or less than a competitive return as prices fluctuate with changing supply and demand conditions. In theory, the current regulatory contract simulates all of these outcomes except the last one. First, like the firm operating in the unregulated market, a regulated, franchised monopoly will not make investments in capacity unless it expects to earn at least a competitive return. Second, the regulatory contract in principle provides the utility with the expectation of earning a competitive return only on investments which were cost-minimizing (given the information available when investment decisions were made) and which are operated efficiently (given the capital stock in place and market conditions at each point in time). Regulatory lag aside, this promise is implemented by setting prices so that revenue just equals the actual (accounting) cost of service incurred by the firm minus the costs of inefficient investments and excessive operating expenses. This means, for example, that if a utility builds an exceptionally efficient plant through luck or skill it is not rewarded by above-normal profits, as a competitive firm would be. On the other hand, suppose a utility forecasts demand to be 100 and adds capacity accordingly, but demand turns out to be only 80, so that much of the capacity is not necessary. In this case the utility is not penalized for its bad luck by subnormal profits, as a competitive firm would be, so long as it can defend its forecasting procedure. Thus the regulatory contract in principle punishes only bad decisions, not bad luck.

If this regulatory contract worked as described, and the supply side and demand side uncertainties were symmetric, consumers would pay on average no more than they would in a competitive market. The time patterns of payments, however, might be very different. For example, in a competi-

tive market with no long term contracts, prices and profits tend to fall when demand for the industry's output falls and excess capacity appears. But under this regulatory contract, prices could actually go up under these conditions, since fewer units of output must cover an unchanged capital cost. This implies, among other things, that regulated prices are not likely to reflect marginal cost changes over time, and consumption decisions will thus be distorted.³⁵

This regulatory contract has not been chosen out of thin air. It makes sense to give legal monopolies to natural monopolies that produce products without good substitutes. Since such firms would have considerable monopoly power if unregulated, it also makes sense to impose price regulation to prevent them from exercising that power to the detriment of consumers. And, since firms must earn at least competitive returns in order to attract the capital necessary to provide service, it is sensible to set rates so that revenues equal costs on average. The prudence test is a response to the obvious undesirability of a pure cost-plus contract, and other regulatory procedures such as straight-line depreciation, detailed hearings, and court review are sensible responses to practical problems of imperfect information and human frailty. But, while the current regulatory contract may be sensible, it may also be far from optimal.

C. *Deficiencies in the Regulatory Contract*

Three basic shortcomings of the present regulatory regime have prompted interest in incentive regulation. First, regulators are not generally very good at distinguishing efficient from inefficient behavior; they simply do not have the information necessary to detect all flawed decisions in a way that would satisfy legal standards for disallowances. Utility managers are always better informed than regulators and have every incentive to make their decisions seem prudent by arguing that poor performance is due exclusively to bad luck. Given the disparity in information, such arguments are difficult to refute. As a result, commissions are usually able to penalize only especially bad investment and operating decisions.³⁶

35. In particular, if it turns out that an *ex ante* efficient investment leads to excess capacity because demand turns out to be lower than expected, average cost pricing would lead to prices above marginal cost and would thus discourage efficient consumption in the short run. Appropriate rate structure adjustments through the use of nonlinear tariffs can, however, minimize these distortions. See *infra* text accompanying note 52.

36. Many utilities that have been or may soon be forced to take large losses because of nuclear plant cancellations would argue that this does not describe their experience. Regulators seem to try to stretch the prudence test in these cases, perhaps because the huge sums involved make their decisions politically sensitive, and ratepayers outvote shareholders. There is also a suspicion that huge disasters simply *cannot* result from prudent decisions. Utilities argue that this puts them in a "heads I lose, tails you win" situation, since they would have received no rewards had the nuclear plants involved turned out to be bargains. These cases are very complex, and the actual quality of utility decision

Moreover, the present system lacks formal incentives for unusually good decision-making that a competitive market provides (though regulatory lag may provide informal incentives for cost minimization). This need not be a serious problem in an industry with a simple, unchanging, well understood technology, where most decisions are routine, bad decisions are easily detected as violations of textbook procedures, and the rewards to creative effort are likely to be minor. But this does not describe the electric power industry today.

Second, given that regulators can directly monitor the performance of regulated firms only imperfectly, the requirement that prices cover virtually all costs incurred could turn regulation into something very close to a pure cost-plus contract.³⁷ That is, absent a credible threat of disallowances, a regulated utility is provided with diminished incentives to supply electricity efficiently. Moreover, in the current economic environment, the usual method of computing capital cost may combine with the political openness of the regulatory process to bias investment decisions against efficient but capital-intensive technologies.³⁸

There is a third potential area of concern rarely mentioned by most proponents of incentive regulation: Average cost pricing leads to prices that do not properly track changes in short run supply and demand conditions. A rule that price equals average total cost will lead to prices that are sometimes too low and sometimes too high, even if the firm makes efficient investment and operating decisions. As long as prices are based on

making undoubtedly varies considerably among them.

37. But, as we discuss *infra* at text accompanying notes 73-74, regulatory lag provides important—though not necessarily optimal or intentional—incentives for cost-minimization that distinguish the current regime from a pure cost-plus arrangement.

38. A simple example illustrates the point. Suppose a utility can choose between two possible technologies to meet a fixed demand. The first has no capital cost and a variable cost of \$100 per year. The second technology requires an initial outlay of \$248.69 to build a plant that will meet demand for three years with no variable costs. One might think of these alternatives as buying power and building a nuclear plant, respectively.

If the discount rate is 10% and variable costs are incurred at the end of each year, it is easy to see that these two projects involve exactly the same present value of costs. Suppose the second option is selected initially. Given the use of straight-line depreciation, rate payers are charged \$107.76 in the first year, \$99.47 in the second year, and \$91.18 in the third year. It is now the end of the third year. If the utility adopts the first technology, rates will rise 9.7% to bring revenue up to \$100. If it builds another plant, however, rates will rise initially by 18.2%. It is easy to see why the first technology might be selected, even if its cost were somewhat over \$100 and it were thus inefficient. Similarly, if the utility were currently buying power for \$105 per year, building the plant described above would raise rates initially, even though it would lower real costs.

Constructing long-lived capital-intensive facilities such as coal or nuclear plants can raise rates in the short run—and thus cause political and regulatory problems—even though the plants would lower costs in the long run. The extent to which actual or anticipated problems of this sort have affected utility decision-making is impossible to determine. Note that this effect is just the opposite of the Averch-Johnson effect that attracted so much attention in the early 1970's. See *supra* note 29.

accounting average cost, rather than true marginal cost, consumption decisions will be socially inefficient.

Most of the interest in incentive regulation reflects concern that the current system creates weak incentives for utilities to make efficient investment and operating decisions. Those who march under the banner of incentive regulation accept the fact that regulators cannot directly, via the prudence test, compel utility managements to minimize cost—indeed, these advocates tend to ignore the possibility of disallowances entirely. Instead, they argue the current cost-plus regulatory contract must be replaced by an arrangement that provides utilities with specific financial incentives to minimize cost, that is, incentives of the same general form as unregulated competitive markets provide.

It is not correct to say that the present regime involves a pure cost-plus contract and thus provides no incentives for cost minimization. In the first place, while the prudence test is an imperfect mechanism for cost control, it is used in practice to punish exceptionally bad outcomes, whether due to inefficiency or not. And, more important, prices are not continuously adjusted so that costs are exactly covered at each instant. Because of regulatory lag, prices tend to stay fixed even though costs are changing, and price changes follow cost changes in time. Regulatory lag partly decouples prices from costs and permits utilities to increase profits by reducing costs in the period prior to rate adjustments. Even if a commission does no direct evaluation of utility decision making, this decoupling provides an incentive for regulated firms to produce efficiently. Regulatory lag is present for administrative reasons, not because it was designed to enhance efficiency, but it is nonetheless an “incentive regulation” mechanism.

Is the actual degree of regulatory lag optimal in any sense? Nobody knows. Moreover, this is not the right question. The proper question is, what set of regulatory procedures, broadly defined, is best? In order to address this question, one must specify the criteria that are to be used to compare alternative regimes. We will assume that a good regulatory system will try to satisfy two primary objectives:

Objective 1 The regulated firm should produce the electricity demanded by its customers at minimum cost in the short run and the long run.

Objective 2 Over time, consumers should pay no more on average than the minimum cost of supplying the electricity they demand.

We further assume that a third objective is of general interest, but not the primary focus of incentive regulation programs:

Objective 3 Prices should be sensitive to prevailing supply and

demand conditions at each point in time, thus reflecting the marginal cost of producing electricity, so as to give the utility's customers incentives to make efficient consumption decisions.

We thus ignore any distributional or political objectives that regulators may have and instead concentrate on economic efficiency in the analysis that follows.³⁹

To be practical, incentive regulation schemes must satisfy several constraints. First, prices must be high enough on average for the utility to be viable financially; otherwise it would not agree to supply the services that have been contracted for.⁴⁰ Second, under current legislation regulators cannot fine utilities or make subsidy payments to them; the procedures and formulas that determine prices must be used to provide incentives. Third, regulators cannot in fact sign binding contracts with the firms they regulate. The commission cannot bind itself today not to change its policies tomorrow, if only because it may be ordered to change policies by the legislature. The implications of these constraints are explored below.

It will almost certainly be impossible to satisfy perfectly each of the three objectives outlined above. Some regulatory procedures may do quite well in one dimension and quite poorly in another. In particular, systems that further decouple prices from costs in order to strengthen the profit payoff to the utility of cost reduction run the risk of sometimes facing consumers with prices that are quite far from current marginal production costs. There may thus be a basic trade-off between our first and third objectives. As in many policy areas, we must seek to identify and evaluate trade-offs of this sort and, inevitably, try to be content with the best that can be done in an imperfect world.

II. Theories of Optimal Regulatory Regimes

The possibility that cost-of-service regulation might provide inadequate incentives for regulated firms to minimize costs has long been recognized. As we point out in Part III, regulators have tried over the years to adapt regulatory procedures to enhance incentives for efficiency. But only in the past few years have economic theorists been able to model formally the basic problem of incentive provision, permitting rigorous analysis of the

39. For a general discussion of appropriate objectives in natural monopoly regulation, see R. SCHMALENSEE, *supra* note 29, at ch. 2.

40. Outright refusal to supply is, of course, quite rare. Utilities more commonly attempt to ride out periods of regulatory severity by cutting investment and maintenance spending sharply, thus quietly refusing to supply high quality service, while trying to overturn unfavorable regulatory decisions in the courts or through the political process. For a discussion of the impact of inadequate earnings on service quality in regulated industries during the 1970's, see A. CARRON & P. MACAVOY, *THE DECLINE OF SERVICE IN THE REGULATED INDUSTRIES* 13 (1981).

optimal design of regulatory institutions and procedures. This Part provides a selective overview of this recent work and discusses what we can and cannot learn from it.⁴¹ Readers should be warned in advance that the flurry of recent theoretical work has so far led to relatively little of practical value. At best, it has reinforced prevailing views about the basic properties of desirable incentive mechanisms.

The recent literature with which we are here concerned departs sharply from earlier theoretical work on optimal pricing and investment decisions for a natural monopoly.⁴² In that earlier work, it was assumed that the regulator had perfect information and could simply direct the utility to minimize costs and to make decisions in the public interest; the question was exactly what decision rules best served the public. The recent literature begins with the assumptions that the regulator has less information than the utility and thus cannot prescribe all its decisions, and that the utility is interested in profit, not social welfare.

A. Agency Theory

Most of the recent work on optimal regulation is an application of what has come to be called agency theory, or the principal/agent model, which provides a general framework for dealing with incentive problems. The basic problem considered by agency theory involves one party, the principal, who hires another party, the agent, to take actions on his behalf. The principal wants the agent to take actions that will make some performance measure as large as possible. In the most general version of this framework, the actual outcome depends on the quality of the agent's actions and decisions, typically referred to as his "effort," on his technological and economic opportunities, and on random factors.⁴³ The principal can observe none of these directly, though he may have some information about the range of technological and economic opportunities, and he may

41. More extensive and formal reviews of these recent developments, accompanied by excellent bibliographies, are provided by Sappington & Stiglitz, *Information and Regulation*, in *PUBLIC REGULATION: PERSPECTIVES ON INSTITUTIONS AND POLICIES* (E. Bailey ed.) (forthcoming) and Baron, *Design of Regulatory Mechanisms and Institutions*, in *HANDBOOK OF INDUSTRIAL ORGANIZATION* (forthcoming). Important contributions to the literature on optimal regulation of utilities include Freixas & Laffont, *Average Cost Pricing Versus Marginal Cost Pricing Under Moral Hazard*, 26 *J. PUB. ECON.* 135 (1985); Sappington, *Optimal Regulation of a Multiproduct Monopoly with Unknown Technological Capabilities*, 14 *BELL J. ECON.* 453 (1983); Baron & Myerson, *Regulating a Monopolist with Unknown Cost*, 50 *ECONOMETRICA* 911 (1982); and Loeb & Magat, *A Decentralized Method for Utility Regulation*, 22 *J. L. & ECON.* 399 (1979); see also sources cited *infra* note 45.

42. See, e.g., W. SHARKEY, *THE THEORY OF NATURAL MONOPOLY* vii (1982).

43. Situations in which the agent's opportunities are known to the principal, so that effort is the only issue, are said to be "hidden action" or "moral hazard" problems. On the other hand, if effort is observable or irrelevant but opportunities (costs, for instance) are not known by the principal, the problem is said to involve "hidden information" or "adverse selection."

know the probabilities attached to the possible outcomes of random processes. The principal attempts to design a mechanism for compensating the agent that will induce him to come as close as possible to maximizing the principal's performance criterion, taking into account the cost of compensating the agent. This compensation mechanism must have the property that the agent can expect (on average, before the actual realization of uncertain variables take place) to recover the costs he incurs. The agent will not agree to any arrangement that does not satisfy this viability constraint. Furthermore, if the relationship involves many periods, the agent will drop out whenever he no longer expects to recover the costs of future actions.⁴⁴ This very general outline has been used, with suitable specific adaptations, to deal with many types of economic and legal problems and associated institutional arrangements. These include labor contracting and wage determination, internal organization and control problems within business firms, control of firm managers by stockholders, defense contracting, long-term contractual arrangements between private buyers and sellers, and, recently, the design of regulatory institutions.⁴⁵

In the regulatory context, the commission is the principal (and, implicitly, the agent of consumers)⁴⁶ and the regulated utility is the agent. Almost all of the regulatory design literature begins with a set of common assumptions. First, the regulator is assumed to have a single, well defined objective. Without such an objective, the concept of "optimal" regulation is not defined. The regulator is usually assumed to maximize aggregate consumer welfare, an objective consistent with the three objectives assumed above. Second, the regulator is constrained to maintain the via-

44. We mention this despite the fact that much of the relevant theoretical work is essentially static, involving arrangements with only two periods. In the real world, contractual relationships tend to be long-lived whenever durable, relationship-specific investments in tangible or intangible assets are required for efficiency. See O. WILLIAMSON, *THE ECONOMIC INSTITUTIONS OF CAPITALISM* chs. 1-3 (1985).

45. For a survey of formal agency theory and its applications, particularly to labor contracting, see O. HART & B. HOLMSTROM, *THE THEORY OF CONTRACT* (MIT Department of Economics Working Paper No. 418, 1986). Other, less formal applications outside the regulatory arena include O. WILLIAMSON, *supra* note 44; Jensen & Meckling, *Theory of the Firm: Managerial Behavior, Agency Costs, and Capital Structure*, 3 J. FIN. ECON. 305 (1976); and P. Joskow, *Contract Duration and Durable Transaction Specific Investments: The Case of Coal* (1986) (unpublished manuscript on file with the Yale Journal on Regulation).

46. An interesting set of problems involves control of administrative agencies by elected officials and the control of elected officials by the public. The general agency framework can address those problems and thus clearly has applications in political science. See, e.g., Kalt & Zupan, *Capture and Ideology in the Economic Theory of Contract*, 74 AM. ECON. REV. 279 (1984); Weingast & Moran, *Bureaucratic Discretion or Congressional Control? Regulatory Policymaking by the Federal Trade Commission*, 91 J. POL. ECON. 765 (1983). The identity of the principal and the agent depends on the nature of the control problem of interest. Here we simply assume that the regulatory agency has the "right" objective function. The relation between regulators' actual objectives and the interests of elected officials and, another step away, the public, is an interesting problem which lies outside the scope of this Article.

bility of the utility. This is consistent both with current law mandating a fair return and with agency theory more generally. Third, the regulator's information is assumed to be inferior to that of the utility's management. Without this key assumption, the regulator could simply become a second management and, if the law permitted, dictate all the firm's decisions in order to maximize the regulatory objective.

The assumption of asymmetric information is quite plausible even though electric utilities publish mountains of data. Regulatory agencies generally have extremely good information about firms' actual accounting costs of providing service. In the electric power industry, considerable effort has been devoted to establishing a uniform system of accounts for financial and operating data, and privately owned utilities are required to make frequent reports on cost, price, financial, and production variables. These reports are subject to audit. They provide a fairly accurate accounting of what the results of the firm's past and present decisions have been on average—subject to the qualification that accounting capital costs at any instant may be substantially above or below true economic capital costs.

But accounting data do not directly reveal the marginal costs that are essential for efficient price-setting. Moreover, a utility's performance in any period depends on the quality of past decisions, especially investment decisions, as well as current decisions, on the economic and technological opportunities and constraints that the utility faces, and on random events beyond the utility's control. The regulatory agency can disentangle the effects of these influences on observed outcomes only imperfectly. For example, the efficiency of a firm's generating units at any point in time will depend in complex ways on a host of observable and—to the regulatory agency—unobservable factors, only some of which are under managerial control.⁴⁷ It is very difficult to imagine that a regulatory agency will ever be able to say that a particular fraction of year-to-year variations in generating unit efficiency is due to current managerial effort and the rest due to other factors. It is even less likely that a regulatory agency will be able to determine whether specific managerial decisions were optimal given the agency's objectives.

Models of optimal regulatory design assume that the regulator's objective is to maximize a measure of consumer welfare, W , that can be expressed in dollar terms,⁴⁸ subject to the constraint that the utility be

47. See, e.g., P. JOSKOW & R. SCHMALENSEE, *THE PERFORMANCE OF COAL-BURNING ELECTRIC GENERATING UNITS IN THE UNITED STATES: 1960-1980* (MIT Department of Economics Working Paper No. 379, rev. April 1986).

48. One such measure commonly employed is consumers' surplus, which is roughly the value of the service to consumers less what they are required to pay for it.

financially viable (i.e., that it expect to recover all its costs). The commission can observe the level of W that results from the regulated firm's decisions, but W depends on several things that regulators cannot observe or can observe only imperfectly. In general these include the degree of effort undertaken by the utility's management, E , (i.e., additional effort results in "better" decisions), the parameters of the utility's cost function, C , (technological opportunities, input prices, etc.), and random events, R , affecting both costs and demands. Increases in managerial effort are assumed to impose costs on the firm, since good managers are expensive and very hard work is unpleasant. The utility selects E to maximize profit, treating the regulatory regime as a constraint. It observes C and R , while the regulator only observes W .⁴⁹ Given the objectives of the firm, the objectives of the regulatory commission, and the information structure, the commission attempts to set up a payment mechanism that will induce the firm to make decisions that yield the highest possible value for the commission's objective function, net of payments by the commission to the utility.⁵⁰ Generally, the payment mechanism will tie the regulated firm's revenues partially to the actual costs that the agency observes and partially to some norm based on prior information that the commission has about costs, demand and the relevant parameters of each.

At first blush, the idea that regulators might purposely set prices so that they depart from marginal cost appears to conflict with the well known prescription of efficient pricing that prices should be set equal to marginal cost. In fact there is a conflict or trade-off between optimal incentives to minimize the costs of production and optimal pricing if regulators only set ordinary (or linear) prices, so that any customer's payment to the utility is just price times consumption, perhaps with a different price for consumption at different times of day or seasons of the year. A utility can only be rewarded by setting total revenue above total cost, and with linear pricing there is no way to do this without inefficiently discouraging consumption by setting price above unit cost. Similarly, consumption is inefficiently encouraged if punishment of the utility takes the form of setting prices below cost.

49. While the regulatory agency cannot observe these variables perfectly, it generally has some prior information about the probabilities of various possible values that will help it fashion a desirable regulatory control mechanism. In some models in this literature, the firm's information is also imperfect, and in others the regulator can acquire information at a cost. The key element is that the firm's information is better than the regulator's.

50. Much of the agency theory literature turns on assumptions about the degrees of risk aversion of the principal and the agent. See works cited *supra* notes 41 and 45; see also *infra* note 52. For problems involving the design of regulatory regimes, which would be applied by the agents of large governments mainly to large corporations, it seems natural to make the simplifying assumption that both the commission and the utility are risk-neutral. This assumption is commonly made in the context of regulatory agencies and the industries they oversee.

To our knowledge the formal literature has not considered this trade-off explicitly. It seems clear, however, that it will generally be optimal to provide weaker incentives for efficient supply in the case of linear pricing, all else equal, than it would be if the commission could levy fines or make payments directly to reflect the tradeoff between production cost minimization and optimal pricing. If ordinary prices are used to provide incentives, more efficient production can only be purchased at the cost of less efficient consumption, while this additional cost is absent if direct payments are possible.⁵¹

Through the use of nonlinear price schedules, according to which a customer's electricity bill is not just some constant times consumption, regulators can in fact fine or subsidize utilities without greatly distorting the price signals on which customers base consumption decisions. To see this, consider the simplest nonlinear schedule, a two-part tariff.⁵² Suppose that a customer connected to the electric utility serving his area pays a fixed monthly charge, F , and a per-kilowatt-hour (kwh) charge P . As long as F is not large relative to a consumer's income, it will neither deter him from consuming electricity at all nor affect the amount he demands. Consumption decisions will thus be based entirely on the variable price, P , which should accordingly be set as close as possible to marginal cost. The fixed charge, F , can be varied to reward or punish the utility. In this scheme a utility's customers are taxed directly—via a fixed charge that yields high profits—to reward the utility; the commission need not draw on general tax revenues. Of course, this form of taxation may be inferior to other taxes from an equity point of view.⁵³ Its main merits are that it is consistent with the actual powers of existing regulatory commissions, and that it is more efficient from the point of view of society as a whole to reward or punish the utility by varying F than to set F equal to zero (i.e., to use linear pricing) and vary P to provide incentives.

The rest of this Part follows the theoretical literature and assumes that

51. See R. SCHMALENSEE, *supra* note 29, where it is argued that the undesirability of having prices far above or below marginal cost may require regulators to link prices more closely to observed costs, and thus to provide weaker incentives for efficient supply, when C and R are highly uncertain. It would follow, for instance, that optimal incentives would have been stronger in the stable 1960's than in the turbulent 1970's. See also Joskow, *supra* note 28, at 316-21.

52. For a model that explicitly takes the approach described here, see Baron & Besanko, *Regulation, Asymmetric Information, and Auditing*, 15 RAND J. ECON. 447 (1984). Declining block tariffs, in which the marginal cost of electricity falls as more is consumed, provide another familiar example of nonlinear pricing. Declining block tariffs have been widely used by public utilities for decades, though not for the reasons stressed here. A two-part tariff is approximated by a declining block structure with two marginal rates (blocks), the first one of which is very high and applies to the first, very small unit of consumption.

53. It should be noted, however, that just as commissions can mandate "lifeline" rates that require serving some consumers at prices below cost, the value of F can, at least to some extent and with an increase in administrative costs, be made lower for poorer or more deserving customers.

regulators can control consumption levels (via P) and utility revenues (via F) more or less independently. It is important to recognize, however, that the practical implementation of schemes that depend on this assumption would require most commissions to modify their usual approach to the design of rate structures, requiring treatment of marginal prices and total revenue levels as independent objectives of roughly equal importance.

B. *Some Prescriptions*

A recent paper by Jean-Jacques Laffont and Jean Tirole both exemplifies the literature on optimal regulatory regimes and derives some suggestive general rules.⁵⁴ Laffont and Tirole consider a regulated firm with the following total cost function:

$$(1) \quad \text{Total Cost} = (R + C - E)q + K.$$

In this equation q is output and K is a fixed capital cost that does not vary with output—a constant known to the firm and its regulator. Unit operating cost has three determinants: R is a random variable reflecting current events beyond the utility's control (such as fuel prices), C is a constant known only to the utility that reflects past investment decisions, and E is chosen by the firm. Greater levels of effort raise E but lower managers' utility. The firm's managers know C , observe R , and choose E , subject to the regulatory rules, to maximize the firm's net profit, defined as accounting profit minus the effective cost to the managers of their effort. The regulator knows the likelihood of all possible values of R and C , but he cannot observe R , C , or E directly. There is assumed to be no uncertainty about demand; both the firm and the regulator know exactly how the quantity demanded depends on the price of electricity.

Laffont and Tirole assume that regulators can observe unit variable (or operating) cost, V , where $V = R + C - E$. Based on the discussion in Part I, this seems a reasonable assumption, perhaps more reasonable than the assumption that capital cost can be determined by either the firm or its regulator using available accounting data. Laffont and Tirole show that the compensation system that maximizes consumer welfare while keeping the utility viable can be described as follows.⁵⁵ The regulatory agency

54. Laffont & Tirole, *Using Cost Observations to Regulate Firms*, 94 J. POL. ECON. 614 (1986).

55. Laffont and Tirole assume that the regulated firm must be kept viable (managers' utility must at least equal some lower bound) for all values of R . This is appropriate if one assumes, as they do, that the compensation schedule will be selected once and for all. But since commissioners cannot bind themselves or their successors never to reverse current policy, and since R and its probability distribution will change over time, it seems more plausible to think of a compensation schedule as being put in place for some relatively short period, such as a year or two. We adopt this interpretation in what follows. It then seems more natural to describe the viability constraint as requiring that the firm must expect to cover its costs on average, since good and bad luck will average out over time. This differ-

issues a rule that describes how the two components, the fixed charge, F , and the per kwh charge, P , of a two-part tariff will be determined. The utility (which is assumed to know C and to have observed R) is then asked to provide an estimate of V , for, say, the next three years. Call this estimate V^e .⁵⁶ Following its stated rule, the regulator then announces that the per-kwh charge, P , in the two-part tariff for electricity will be set equal to this estimate.⁵⁷ Given P , the commission computes the quantity of electricity that will be demanded, q , from its (assumed) knowledge of the demand curve. Finally, the commission follows its stated rule and announces that the fixed charge, F , will vary each year depending on the actual level of V that is observed in such a way that the utility's actual revenue in each year is determined by the following function:

$$(2) \text{ Total Revenue} = K + [B(V^e) + V^e q] + S(V^e)[Vq - V^e q]$$

In this scheme the commission's tariff describes the $B(V)$ and $S(V)$ functions; the actual values of B and S used in this equation to compute the utility's allowed revenue depend, as indicated, on the utility's subsequent estimate, V^e .

The actual revenue earned by a firm in each of the years following a formal rate case has three components as shown in equation (2). The first is its capital cost, K , which by assumption is beyond the utility's current control. The second component is also fixed. It is equal to expected operating cost, $V^e q$, plus a bonus, B , which may in principle be positive or negative. In the third term in this equation, S is always between zero and one. Thus the utility recovers in revenues only a fraction of the difference between the actual operating cost incurred and the initial estimate of that cost. Note that there is no prudence test here; the commission never tries to see if cost overruns are due to bad management or bad luck.

Besides demonstrating that given all of the underlying assumptions, a revenue function of this form can give optimal incentives for cost reduction, Laffont and Tirole also derive some interesting properties of the optimal B and S functions. First, it is never efficient to have a pure cost-plus contract; S is always strictly less than one. Second, the higher the

ence does not seem essential in the present context, though changing the exact form of the viability constraint may alter some details of the Laffont-Tirole results. The possibility of future reviews raises more serious problems. See *infra* text accompanying note 72.

56. In the theoretical analysis, V^e is simply a bid submitted by the utility. In practice it might reflect *pro forma* future test year accounting rules.

57. In fact, as Laffont and Tirole show, it may be optimal to set P above V^e if high values of F produce efficiency losses. See Laffont & Tirole, *supra* note 54. It is only optimal to set the variable charge equal to marginal cost if the fixed charge is, in effect, a perfect tax that does not produce distortions elsewhere in the economy. As above, we assume here that it is such a tax. This does not seem a bad assumption in the case of electricity.

utility's cost estimate, relative to regulators' expectations, the lower the fixed bonus, B , but the higher the fraction of cost overruns that the utility will be allowed to recoup, S . Thus firms that estimate *ex ante* that costs will be relatively high get a relatively small fixed payment but bear a relatively small share of the risk of cost overruns or underruns. Third, it is efficient to set S close to zero if V^e is close to the lowest possible value of V . Thus if there is very little uncertainty about V , so that the highest and lowest possible values are close together, the utility will be operating most of the time at something very close to a fixed price contract. Its revenue will depend almost entirely on its estimated cost, not its actual cost. On the other hand, if there is significant uncertainty, the utility and its customers will generally share the risk that cost will depart from expectations.

The work of Laffont and Tirole both supports the general principle that a good incentive mechanism usually involves some sharing of the risks of cost overruns between a utility and its customers and offers some suggestive insights. But it also illustrates the complexity of the problem of designing optimal incentive schemes. Even under the strong assumptions made in this analysis, the commission must select functions B and S that depend in complex ways on all of the regulator's information about demand conditions, about the probabilities of alternative values of the cost parameters R and C , and about the cost of various levels of effort to the utility. The problem would be even more difficult if there were uncertainty about demand, if the cost function were not of a known simple form, or if the commission did not know the cost of alternative levels of effort to the utility.

Like most of the economics literature, the Laffont-Tirole regulatory model is essentially static: the commission and the utility make one decision each. Capital costs and the stocks of plant and equipment they reflect are taken as fixed. But, in fact, the relationship between a regulatory agency and a regulated firm is dynamic. Firms and commissions are playing a game over many periods. Over time, the underlying parameters of the cost and demand structures will change because of the utility's investment decisions, technical progress, and changes in markets for inputs and in the economy as a whole. Optimal incentive schemes must be designed in light of possible structural changes and must be modified when such changes occur. Regulation directly affects investment decisions, and a fully optimal regulatory regime must provide incentives for efficient investment as well as for efficient operation. It must also be recognized that changes

in the regulatory regime will alter the riskiness of the utility and thus generally affect its cost of capital.⁵⁸

Most fundamentally, the nature of the game played by the regulator and the firm changes dramatically when both make decisions over time. In principle, the commission can use repeated observations of firm performance to improve its information, and use that information to fine-tune rewards and penalties. Knowing this, the firm has an incentive to try to fool the regulator, perhaps even raising costs and sacrificing profits today in order to make tomorrow's reward/penalty structure more favorable.⁵⁹ Since public utility commissioners cannot sign contracts that prevent themselves or their successors—not to mention current and future legislatures—from changing policies, they cannot solve this problem by promising not to use what they learn. Such a head-in-the-sand policy would be plainly irresponsible even if it were credible. When incentives to deceive are taken into account, the problem of designing an optimal dynamic regulatory regime moves to a new level of complexity. These dynamic considerations have proven to be very hard to analyze, even in simple models.

The theoretical literature to date thus makes strong assumptions but has nonetheless not produced a neat set of cookbook rules that can be readily applied with available empirical information to develop optimal or even good incentive mechanisms for electric utilities. Nothing as useful as "base prices on marginal costs" has been discovered. We strongly suspect that this reflects the inherent difficulty of the problem more than the immaturity of the literature.⁶⁰ Practical rules are even less likely to emerge from more general work that allows for additional, realistic sources of uncertainty, that considers incentives for efficient investment decisions as well as efficient operating decisions, and that does justice to the dynamics of real regulatory relationships.

All of this at least shows that no single incentive scheme will be optimal in all circumstances and that the appropriate incentive scheme for any particular firm may change dramatically over time as economic conditions and the commission's information change. No doubt, more progress on the

58. In particular, incentive regulation will raise the cost of capital if it increases the "systematic risk" of the utility—the extent to which the utility's earnings vary directly with aggregate economic activity.

59. See, e.g., Sappington, *Strategic Firm Behavior Under a Dynamic Regulatory Adjustment Process*, 11 *BELL J. ECON.* 360 (1980); Vogelsang & Finsinger, *A Regulatory Adjustment Process for Optimal Pricing by Multiproduct Firms*, 10 *BELL J. ECON.* 157 (1979). See generally Baron, *supra* note 41.

60. The typical pattern in theoretical economics is that the first few papers on any particular subject produce simple, neat results, many of which are then shown by later work to be correct only under very special circumstances.

theoretical front will be made in the next few years. At this point our theoretical understanding of the mechanism design problem, along with the analysis of the current regulatory regime in Part I, points to eight interesting insights which, unfortunately, offer relatively little specific guidance for application to electric utilities:

First It is generally desirable at least partially to decouple the compensation a regulated monopolist receives from the actual accounting costs that it incurs: pure cost-plus regimes are almost never optimal. Regulatory lag automatically accomplishes this to some extent, but there is no reason to think that the current system provides optimal incentives for efficient electricity supply. The magnitude of the optimal decoupling will vary directly with the ability of the regulatory agency to determine what “efficient” cost should be and indirectly with the economic and technological uncertainties the firm faces. Nonlinear pricing can be used to provide better incentives at lower social cost than ordinary linear tariffs.

Second The design of incentive mechanisms requires careful definition of the commission’s objectives, what information it has, and the nature of uncertainties about cost and demand. The incentive mechanism must be sensitive to changes in underlying economic conditions. When economic and technological uncertainty increases, it is generally optimal to reduce the strength of incentives, to move away from fixed-price contracts and toward (but not all the way to) cost-plus regimes. This suggests that incentive schemes must be regularly redesigned, just as tariffs are now. On the other hand, compensation rules must be kept fixed for reasonably long periods (and utilities must anticipate that this will happen) if they are to have noticeable effects on behavior.

Third Incentive payments ideally should be based on comprehensive measures of performance. If cost minimization is the performance norm, for example, an incentive provision tied to generating unit reliability rather than total costs could be counterproductive. The reason for this is simple: A regulated firm will act in its own self-interest and try to improve only the performance measure on which it is graded, at the expense of other dimensions of performance. If an incentive scheme makes it profitable to increase generating unit reliability, but does not penalize excessive maintenance or capital expenditures, the firm may spend large sums of money to improve reliability but in the process increase total costs.

Fourth Incentive regulation schemes work by inducing management to make efficient decisions. This suggests that rewards and penalties should be tied closely to outcomes that are in fact subject to managerial control. It makes little sense to reward or penalize management for random events they cannot affect. But it is usually impossible to avoid doing

this in practice to some extent, since the basic problem is that commissions cannot sort out the impacts of effort from those of random events.

Fifth Any good incentive mechanism must anticipate allowing the firm to earn profits above the cost of capital when some contingencies arise and less than the cost of capital when other contingencies arise. The rules of the game must be such that the firm expects at least to recover its costs on average over time.⁶¹

Sixth Since regulators may find it politically difficult to avoid changing policy when utilities earn very high or very low profits, schemes that are likely to produce such outcomes may not be credible. If a firm does not believe it will be allowed to earn high profits for superior performance, for instance, a promise to that effect will provide no incentives at all for more efficient supply. It may be desirable to limit rewards and penalties to politically acceptable levels to convince utilities that the announced incentive scheme actually will be followed.

Seventh As a practical matter, incentive schemes must mesh well with current regulatory accounting principles. These schemes in the past have been superimposed on existing utility, regulatory, and accounting structures and procedures. Absent major legislative changes, this will also be true in the future. Incentive schemes are usually viewed as experimental, and comparisons with traditional procedures are made. In any event, some cost accounting system will be required and it is unlikely that regulators will abandon the one that has been operating for so many years. This implies, in particular, that regulators will have much better information about real operating costs than about real capital costs and suggests the difficulty of using incentive schemes to improve the quality of investment decision making.

Eighth Even in theory, optimal incentive schemes cannot produce perfect performance. Regulation is inherently inferior to competition in this regard. Moreover, a poorly designed incentive scheme can yield results that are worse than those produced by prevailing regulatory arrangements. Incentive payment schemes should be evaluated in the context of, and integrated with, other regulatory control mechanisms such as unavoidable regulatory lag and direct disallowances of imprudent expenditures.

61. Laffont-Tirole and some other works suggest that optimal incentive mechanisms may generally yield expected returns on investment that are in fact somewhat higher than the firm's cost of capital. See Laffont & Tirole, *supra* note 54; Sappington & Stiglitz, *supra* note 41; Baron, *supra* note 41. The basic argument is that the viability constraint limits the use of penalties to provide incentives, so that if strong incentives are desirable, generous bonuses may be required. It is not clear to us how seriously this result should be taken in practice, since it may be driven by the interpretation of the viability constraint discussed *supra* note 55.

III. Incentive Regulation in Practice

Modern economic theorists are not the first to have noticed the weaknesses of cost-plus regulation; participants in and observers of public utility regulation have been aware of them for many years. A variety of different approaches for building better incentives into the regulatory process have been suggested over the years, and some have been employed from time to time. Indeed, efforts to develop incentive schemes are at least as old as public utility regulation itself.⁶² In recent years there has been a renewed interest in these mechanisms. This interest has been motivated in part by inflationary conditions that have produced rapid, politically unpopular increases in nominal electricity rates. The view that “it ain’t broke, so don’t fix it” has also been weakened by the brownouts and blackouts of the early 1970’s, current widespread excess capacity, and the ongoing cancellation of unfinished and enormously expensive nuclear generating plants. In addition, the success of deregulation in other sectors has naturally suggested to many policy makers that it must be possible to “do something about electricity.” The availability of better theoretical tools has played at most a small part; debates about incentive schemes have tended to involve the lessons of history and common sense more than those of formal theory.

A. *Approaches to Incentive Regulation*

This Part shifts the focus from the search for the “best” compensation arrangements to incentive regulation schemes that have been proposed as “good,” or better than the status quo. We begin with a review of some widely discussed approaches to incentive regulation and then report on recently adopted incentive schemes in the United States.

1. *The Sliding Scale*

The first of the so-called “sliding scale” plans was employed in England in the middle of the last century.⁶³ These plans call for ordinary, linear prices to be adjusted automatically when the utility’s actual rate of return differs from its predetermined “fair” or target rate of return on investment. If a firm manages to lower its costs, so that its rate of return rises above the target, prices are lowered. But the price reduction is

62. Indeed they are older, since the same types of problems naturally emerge with municipal franchise contracting for public utility services, the precursor institution to commission regulation. For an overview of incentive schemes discussed before the 1980’s, see R. SCHMALENSEE, *supra* note 29. For a discussion of municipal franchising, see *id.* at 51-53, 76.

63. For a general discussion of sliding scale plans and their history, see *id.* at 126-30.

designed to leave the firm with some excess profits so as to provide an incentive for efficiency.

These schemes have taken a variety of different forms, but the simplest would look as follows. Let r^* be the target rate of return (revenue minus operating costs and depreciation divided by the book value of capital) and let r_t be the actual rate of return at the prices that initially prevail in year t . Then the sliding scale would adjust prices so that the actual rate of return, r_t^a , at the new prices would be given by:

$$(3) \quad r_t^a = r_t + h(r^* - r_t),$$

where h is a constant between zero and one. Thus if at prevailing prices the earned rate of return falls below r^* (which we may assume is the utility's cost of capital), rates are adjusted upward to increase the rate of return by a fraction, h , of the difference between the earned rate of return and the target rate of return. Notice that in equation (3), as in the Laffont-Tirole "optimal" mechanism discussed in Part II and in most other incentive schemes, the utility and its rate-payers explicitly share both risks and rewards.

To implement a sliding scale plan, an initial rate hearing must establish the target rate of return, r^* , and determine prices that are expected to yield the firm an earned rate of return equal to r^* , as under conventional procedures. In addition, the commission must select the "sharing constant", h . If h equals one, the utility earns the target rate of return in each period; regulation is essentially cost-plus. The discussion in Part II indicates that h should be smaller—and regulation closer to a fixed-price contract—the less important the perceived economic and technological uncertainties faced by the utility. Thereafter, prices are regularly adjusted according to equation (3) until the next rate hearing, several years later.

A sliding scale scheme of this general type for sales of electricity was used in Washington, D.C., between 1924 and 1955. During this period of time electricity prices fell (as they did throughout the United States) and profits were high. The scheme broke down during the 1950's under the stress of inflation. A more complicated plan was introduced in New Jersey in 1944 to govern prices charged by New Jersey Power and Light Company. The plan was in effect for four years and was then withdrawn at the company's request.⁶⁴ The sliding scale approach has several virtues. First, it is easy to explain and understand. Second, it does provide explicit incentives for cost minimization. Third, it meshes nicely with traditional utility accounting and rate-making principles and thus can be applied

64. For brief discussions of these experiences and a set of references, see *id.* at 127.

readily to an existing firm that has been operating for many years subject to cost-of-service regulation.

But sliding scale plans also have serious shortcomings. The first is that the utility is rewarded for minimizing total accounting cost. Because of the way capital cost is treated in utility accounting,⁶⁵ this may not lead it to minimize the real, economic cost of electricity supply. A second and even more serious problem with the simple sliding scale mechanism is that it yields prices that are persistently too high or too low when underlying economic conditions change. For example, if input prices rise over time because of inflation, the utility's rate of return will decline over time, even if it produces efficiently. If technological change reduces the costs of generation and transmission equipment, the opposite will occur. A desirable incentive payment mechanism must take account of observable changes in input prices, technological opportunities, and demand conditions that are beyond the utility's control. The sliding scale approach fails to do this. A third problem is that the sliding scale approach fails to recognize the multiproduct character of electric utilities.⁶⁶ The sliding scale, like most incentive schemes, determines only the average level of prices. Increases or decreases in the prices for individual services could either be tied to the average change, or left to the company. Either approach is potentially problematic.

2. *Partial Overall Cost Adjustment Mechanisms*

A number of schemes have been suggested that provide for automatic price changes based on differences between the actual total cost of service and some baseline figure, such as the cost per kwh determined from test year data during a formal rate hearing.⁶⁷ Incentives for cost reduction are provided by having prices move up and down less than proportionately with changes in costs. To see how these schemes work, let C^* be the estimated cost per unit of output of the firm, as determined in a regulatory hearing, and let C_t be the actual cost per unit in some future period. Then, in the simplest case, we might allow for periodic price adjustment according to the formula:

65. See *supra* note 26.

66. While at one level of abstraction these firms produce only electricity, the costs of serving different classes of customers at different times of day and seasons of the year are not the same, nor are corresponding demand conditions. It is thus analytically useful to treat electric utilities as producing multiple products, even though the electrons involved are identical.

67. Several of these proposals are analyzed in R. SCHMALENSEE, *supra* note 29, at 121-26.

$$(4) \quad P_t = C^* + g(C_t - C^*),$$

where g is a constant between zero and one.

As written, this adjustment formula presents all the same problems noted above in connection with sliding scale pricing. A number of authors have proposed to deal with the most important of these—the tendency for the utility's minimum possible cost to change over time—by incorporating input price changes and expected productivity growth.⁶⁸ That is, instead of coming up with a single number, C^* , the regulator would announce an expected average cost function that would be used to produce a set of values of C^* over time. These values would then depend, in a specified way, on changes in input prices and technological opportunities.

This modification of equation (4) requires the regulator to estimate how minimum costs are expected to change with changes in input prices, output, and technological change.⁶⁹ The commission would have to produce a function like the following:

$$(5) \quad C_t^* = C^*(w_t, q_t, t).$$

In this equation w_t is a vector of input prices in year t and q_t is output (or a vector of outputs), which is included to capture the effects of economies of scale and scope, and of changes in capacity utilization. Finally, time, t , is included to reflect expected patterns of productivity change over time. Ideally, in order to provide incentives for efficient procurement, the input prices used would reflect the opportunities faced by the firm (as reflected, for instance, in spot prices or published price series for the relevant inputs) rather than the input prices actually paid by the firm. The weights given the various input prices should reflect the expected effects of input price changes on total costs. The weight given to the output vector would reflect economies or diseconomies of scale and scope, and the effects of changes in capacity utilization on cost. The weight given to time would

68. See, e.g., M. FOLEY & R. TUCKER, *ELECTRIC UTILITY PERFORMANCE STUDY, 1972-1984* (1986); L. ANSELIN & J. HENDERSON, *A DECISION SUPPORT SYSTEM FOR UTILITY PERFORMANCE EVALUATION* (1985); L. JOHNSON, *INCENTIVES TO IMPROVE ELECTRIC UTILITY PERFORMANCE: OPPORTUNITIES AND PROBLEMS* (1985); Cowing, Stephenson & Small, *Comparative Measures of Total Factor Productivity in the Regulated Sector: The Electric Utility Industry*, in *PRODUCTIVITY MEASUREMENT IN REGULATED INDUSTRIES* 161 (1981); Tenenbaum, *Using Statistical Cost Functions to Assess the Relative Productive Efficiency of Investor-Owned Electric Utilities*, in *CHALLENGES FOR PUBLIC UTILITY REGULATION IN THE 1980'S* (H. Trebing ed. 1981).

69. Something of this sort would be necessary to make the Laffont-Tirole scheme discussed in Part II operational. Even though in that scheme the utility is allowed to produce a new cost estimate each period, the commission's optimal response to any given estimate depends on the actual economic and technological conditions at the time it is made. Moreover, if we are thinking of applying this to an existing firm that has been regulated under traditional rate-making principles, the function used to determine C^* in any period should be an engineering/accounting cost function that embodies regulatory accounting principles rather than an "economic" cost function.

reflect expected (accounting) productivity growth, as determined by both technical change and accounting depreciation rules.

Equation (5) would be used to develop a base price for each period, which would depend on the actual values of the independent variables for that period. This moving target would be plugged into equation (4) to determine adjustments in the average level of rates:

$$(4') \quad P_t = C_t^* + g(C_t - C_t^*).$$

The primary practical problems here are identifying the appropriate independent variables in the cost function, determining the appropriate weight for each variable, and finding good input price series. These difficult problems are complicated by the need to mesh the cost function with utility accounting procedures. The appropriate weights and input price series will vary from firm to firm. And, as with any incentive payment scheme, it will not be easy to arrive at an appropriate value for the sharing fraction, g , or to account for the effects of the new regulatory procedures on the cost of capital.

The use of a cost function such as equation (5) underlies at least implicitly proposals to make use of total factor productivity (TFP) indexes or statistical cost functions to rank the performance of utilities in order to determine penalties and rewards.⁷⁰ Several efforts have been made to use accounting cost, input price, input utilization, and output to estimate statistical cost functions and productivity indexes for electric utilities. We believe these efforts have shown that this approach leads to extremely unreliable measures of relative performance. For example, in one recent study long run cost indexes were calculated for a large sample of utilities and rankings were listed for various years.⁷¹ The year-to-year variations in rankings were sometimes so large that, in light of our previous discussion of utility cost accounting, we find it doubtful that the rankings are particularly meaningful in and of themselves. Even though most power plants remain in operation for well over a decade, a utility that was ranked ninth in 1973 was ranked forty-ninth eight years later, and a utility that was ranked seventy-fifth in 1973 was ranked fifth in 1981. While it is also true that several utilities were either persistently "good" or persistently "bad," we suspect that this reflects in large part inherent cost differences between utilities, perhaps reflecting to some extent investment decisions made many years ago, that were not fully captured in the econometric analysis. While we do not feel that these rankings or similar

70. See *supra* note 67.

71. L. ANSELIN & J. HENDERSON, *supra* note 68, at table F-1.

approaches are useless, we do believe that they should be used with great care.⁷²

3. *Indexed Rates and Institutionalized Regulatory Lag*

As indicated in Part I, the existing regulatory regime is not properly viewed as a pure cost-plus contract. Price rigidities are built in as a consequence of regulatory lag. Regulatory lag provides at least some additional incentives to minimize costs. Price rigidities due to regulatory lag were quite significant for most utilities until about 1970.⁷³ As input prices began to increase more rapidly and cost savings due to productivity growth and further exploitation of economies of scale disappeared or turned negative in the 1970's, regulatory lag became less important for electric utilities.⁷⁴ Rate cases were more frequent and automatic adjustment clauses, especially for fuel costs, became very important. Rather than being fixed for relatively long periods of time, prices were adjusted more and more quickly to reflect cost changes. It is natural to ask whether there is some way that regulatory lag might effectively be reintroduced even though nominal input prices change relatively quickly and rapid price adjustment is necessary to keep utilities viable.

William Baumol has argued that an "indexed rate" provision would preserve the benefits of regulatory lag without incurring its costs when nominal input prices are rising rapidly.⁷⁵ In its simplest form the proposal allows base rates to be set in a regulatory proceeding and increased automatically thereafter to reflect changes in some general price index, such as the Consumer Price Index (CPI), less an adjustment, usually denoted as X , for expected productivity growth. This is frequently called the "CPI - X " indexing approach, and is summarized by the following equation:

72. There are technical problems with this general approach. For instance, the analysis is completely static, which is quite inappropriate for a capital intensive industry in which future demands, input prices, and technical opportunities are uncertain, and investment decisions are made long before facilities are completed. For a discussion of the reasons why the New York State Public Utilities Commission concluded that total factor productivity (TFP) studies should not be mandatory in rate cases, see Robinson, *Total Factor Productivity Studies as a Rate Case Tool*, PUB. UTIL. FORT., March 13, 1980, at 19.

73. See Joskow, *supra* note 28, at 311. Indeed, in this period some authors proposed institutionalizing regulatory lag in order to improve efficiency incentives. See, e.g., Baumol, *Reasonable Rules for Rate Regulation: Plausible Policies for an Imperfect World*, in PRICES: ISSUES IN THEORY, PRACTICE, AND PUBLIC POLICY (1967).

74. Many utilities would argue that, while the length of time between rate adjustments did decline, the decline was not substantial enough to make up for rapid increases in the costs of production; as a result, the utilities still had substantial incentives to minimize costs.

75. Baumol, *Productivity Incentive Clauses and Rate Adjustment For Inflation*, PUB. UTIL. FORT., July 22, 1982, at 11.

$$(6) \quad P_t = P_{t-1}(1 + \% \text{ change in CPI} - X).$$

This approach is really just a special case of the partial cost adjustment approach discussed above. Equation (6) can be derived by making two simplifying assumptions about the relationships in the partial cost adjustment model. First, a very simple cost function is used in equation (5). Second, the sharing fraction, g , in equation (4) is set to zero. To see this, let us begin with initial prices set equal to estimated costs during the test year:

$$(7) \quad P_{t-1} = C_{t-1}.$$

Suppose that the cost function, equation (5), can be adequately approximated by a very simple relationship instead of a complicated function:

$$(8) \quad C_t = C_{t-1}(1 + \% \text{ change in CPI} - X).$$

Substituting equation (8) into equation (4') and using equation (7), we get

$$(9) \quad \begin{aligned} P_t &= C_t^* + g(C_t - C_t^*) \\ &= C_{t-1}(1 + \% \text{ change in CPI} - X) + g(C_t - C_t^*) \\ &= P_{t-1}(1 + \% \text{ change in CPI} - X) + g(C_t - C_t^*). \end{aligned}$$

If $g = 0$, then (6) and (9) are identical.

Thus under the indexed rate proposal, the sharing fraction, g , is set to zero so that the utility bears all of the benefits and all of the costs of deviations between the target (or expected) cost and the actual cost. It is unlikely that this is optimal, even if (8) were an adequate approximation of the true underlying cost function.

Much of the appeal of the CPI - X approach stems from the fact that it looks so simple. But this simplicity is artificial, at least for electric utilities. There is absolutely no reason to believe that simple equations such as (8) are likely to provide accurate predictions of utilities' minimum future costs. Broad-based indexes like the CPI are designed to measure the general average rate of price changes; they are not especially sensitive to the prices of any particular utility's inputs. Nor is there any obvious way to come up with good, simple estimates of expected productivity growth. Furthermore, this approach is likely to mesh extremely poorly with prevailing regulatory accounting principles, which do not reflect the current costs of plant and equipment. In the end we are back to having to come up with a formula such as equation (5) to get the right index. And, since there is also no reason to think that g should generally be zero, the right way to think about indexed rate approaches is as special members of the

family of partial comprehensive cost adjustment schemes, with no particular attraction in their own right.⁷⁶

4. *Yardstick Approaches*

Although electric utilities operate in franchised geographical areas and do not compete directly with each other, there are a relatively large number of utilities around the country. If they operated in a single perfectly competitive market, the price faced by any one seller would be determined by the costs of all its rivals. One might imagine simulating this process by basing a utility's prices not on its own costs, but on the costs of other comparable utilities operating under similar conditions. This would be a strong and comprehensive version of what is often called yardstick competition, in which any particular utility is evaluated in terms of its performance relative to other firms.⁷⁷

Specifically, suppose that a set of N comparable privately owned utilities could be identified. "Comparable" means that they face the same production opportunities and demand functions. Let the total cost per kwh for the j th such firm in some year be C_j and let AC_i be the average of the C_j for all $(N-1)$ firms in this group *excluding* firm i . Strong, comprehensive yardstick competition could be implemented by setting firm i 's price (i.e., its average revenue per kwh) equal to AC_i . The prices for all other firms would be determined in exactly the same fashion.⁷⁸ At least in theory, this approach completely eliminates the cost-plus character of regulation and provides all firms with strong financial incentives for cost reduction. Each firm's prices are completely independent of its own costs. If the firm can reduce its costs below the average it can make money. If not, it does not cover all its costs. By setting prices in this way, regulated firms are forced to behave as if they were competing with one another. Each firm tries to beat the average as it seeks to maximize profits. In the process, the costs of all firms converge to the minimum level. The comprehensive yardstick approach is broadly similar to the use of Diagnostic Related

76. The CPI - X approach has been applied to the regulation of the recently privatized telephone system in the United Kingdom, where it is called "RPI - X". See J. VICKERS & G. YARROW, *PRIVATIZATION AND THE NATURAL MONOPOLIES* 39-43 (1985). It is important to note that the RPI - X regime is intended to be temporary; it is slated for review in 1989, and the entire industry is expected to be deregulated in the not too distant future.

77. This is different from the yardstick notion used by public power proponents. Yardstick competition is only sensible if it involves comparable firms. Publicly owned firms with access to subsidized capital and preference power cannot be usefully compared to privately owned firms that lack these advantages. See P. JOSKOW & R. SCHMALENSEE, *supra* note 2, at 17-18.

78. For a formal analysis of this scheme, see Shleifer, *A Theory of Yardstick Competition*, 16 *RAND J. ECON.* 319 (1985).

Groups (DRGs) and associated prices by Medicare to determine reimbursement of health care providers for government subsidized treatment.⁷⁹

While utilities are often compared to one another informally, direct application of the comprehensive yardstick approach described above to electric utilities would be plagued by two major problems. First, this approach only works if one can find a fairly large sample of truly comparable utilities or can somehow adjust for differences among utilities. Utilities differ from one another in so many dimensions, not only because of current market conditions but also because of past investment decisions, that we are not likely to find a large number of truly comparable utilities. The best that we can do is to use statistical techniques to standardize for differences in supply and demand conditions across utilities. As the above discussion of statistical cost and productivity studies indicates, we can do so only imperfectly. This implies that comprehensive yardstick approaches to rate setting would impose highly random rewards and punishments; inefficient utilities might prosper while efficient producers might not be viable, and prices would often be out of line with both actual and minimum attainable costs.

Second, not only must the utilities that “compete” with each other face comparable economic and technical opportunities and constraints on the supply and demand sides, but they also must be comparable from a regulatory accounting point of view. If they are not, comparisons of accounting cost data will be meaningless. For example, two utilities may be identical except that they are out of phase with one another in the completion of new generating facilities. Utility 1 completes a large coal plant in 1980, while Utility 2 completes an identical plant at an identical real cost in 1985. Even if the two firms always have identical economic costs, regulatory accounting will show different costs for them at each instant. If these firms have different histories—for example, because one was able to exploit a good hydroelectric power source sixty years ago—accounting cost differences will be magnified. Again, meshing an economic incentive mechanism with traditional utility accounting practices raises serious problems. Abandoning traditional accounting practices would likely give either consumers or utilities a large windfall gain. And, as a practical matter, these practices are not likely to be abandoned, since any set of incentive payment mechanisms will most likely be introduced as a supplement to traditional cost-of-service regulation rather than as a replacement for it.⁸⁰

79. For a discussion of DRGs, see Morone & Dunham, *Slouching Towards National Health Insurance: The New Health Care Politics*, 2 YALE J. REG. 263 (1985).

80. Note also that if only a single state or a few jurisdictions adopted a “strong yardstick” ap-

5. *Incentives Tied to Components of Cost or Performance*

All of the approaches discussed thus far embody "comprehensive" incentive provisions in the sense that the target is overall cost or performance, rather than a particular component of cost or performance. As we indicated above, a comprehensive approach is desirable in principle to avoid creating adverse incentives favoring one element of cost or performance over another. On the other hand, available data provide better measures of some components of cost and performance than of others. In particular, as we have noted repeatedly, operating cost is easier to measure than capital cost. And, as we shall see below, most attempts by regulatory commissions to implement incentive regulation have eschewed comprehensive measures and focused instead on specific components of utility cost or performance. As the following examples indicate, the basic approaches discussed above can generally be applied to specific components of utility costs or performance in a straightforward way.

a. *Fuel Cost Indexing*

On average, fuel costs account for about 40% of the price of electricity,⁸¹ although this percentage varies widely across utilities. In the short run, with the capital stock in place, the primary opportunities for cost savings are in the areas of fuel utilization and procurement. The extensive use of fuel adjustment clauses, which tend to raise rates automatically as the cost of fuel increases, makes this short run condition of particular concern.⁸² On the one hand, automatic adjustment provisions are desirable because they allow prices to move quickly up and down to reflect changes in the costs of production, thus giving consumers signals consistent with Objective #3 in Part I. In a period of rapidly rising fuel prices, such provisions keep the utility viable, and in a period of falling fuel prices, they prevent utilities from reaping windfall profits. However, to the extent that a utility gets no benefit from lowering its fuel costs and bears no

proach, the firms under its jurisdiction would be compared mainly to other utilities which would generally face weaker incentives for efficient supply. The incentives facing the "strong yardstick" firms would thus be weaker than optimal. This approach would clearly work best if it were applied to all firms in the comparison group, but this would require more interstate regulatory coordination than has been the historical norm. Regulatory reforms have often been tested first in a few states and only applied in other states once the innovation has a proven track record. The inherent weakness in the yardstick approach noted here may prevent its widespread application, because other states will not be able accurately to gauge the potential benefits from yardstick pricing by observing the experience a few "laboratory" states have with the program.

81. See EDISON ELEC. INST., *supra* note 7, at tables 71 and 72.

82. Many fuel adjustment clauses currently in force require a hearing before rates can be changed. At least until recently, however, most of these hearings appear to have been *pro forma*.

burden if they rise, a cost-plus contract with its associated incentive problems has in effect been put in place.

It is useful to divide the fuel-related incentive problem into two parts. First, we want to create incentives for utilities to purchase fuel at minimum cost. Second, we want to give utilities incentives to operate their plants efficiently, generating from the lowest-cost plants at all times and making optimal maintenance and operating decisions. While both fuel costs and fuel consumption have large random components, both can be controlled to a significant extent by utility managements. Incentive schemes to encourage efficiency on both fronts might be very desirable, although it must be recognized that there will be difficulties involved and that too much emphasis on fuel cost minimization may lead to cost increases in other dimensions. Some type of partially- or fully-indexed cost adjustment provision, such as those described in equations (2) or (4) above, could potentially be adapted to achieve these objectives.

For example, automatic fuel adjustment clauses might use price indexes for each fuel rather than the actual prices paid by a utility. This approach might then be extended to incorporate expected fuel utilization rates at different output levels in order to encourage efficient fuel utilization. This extension, however, would require adjustment for the specific ways individual generating units were used in the system in particular periods. Moreover, such a plan must be carefully designed so as not to bias choice among alternative generating technologies and modes of operation.

b. *Generating Unit Performance Targets*

The yardstick notion could be applied to the performance of a utility's generating units rather than to the utility as a whole. The two most important dimensions of generating unit performance are a unit's heat rate and its equivalent availability.⁸³ There are at least a hundred generating units that employ each of the four major fuels—coal, oil, gas, and nuclear—used to generate electricity. While very few units are truly iden-

83. A generating unit's heat rate is the number of British Thermal Units (btu's) of fuel required to generate a kwh of electricity. The lower the heat rate, the less fuel is used and the lower are the costs, other things equal. The average heat rate for the electric utility industry's generating capacity is about 10,500 btu/kwh. A generating unit's equivalent availability factor (EAF) measures the fraction of a year during which a generating unit is available to generate electricity at its full capacity. (Generating units are unavailable due to planned maintenance and random equipment outages). Other things equal, the higher a unit's equivalent availability, the lower will be the capital costs of generating electricity. Fossil-fueled steam-electric units have an average equivalent availability factor of about 80%. For more detail see P. JOSKOW & R. SCHMALENSEE, *supra* note 2, at 48.

For discussion of these measures and their determinants for coal-fired plants, see Joskow & Rose, *The Effects of Technological Change, Experience, and Environmental Regulation on the Construction Cost of Coal-Burning Generating Units*, 16 RAND J. ECON. 1 (1985) and P. JOSKOW & R. SCHMALENSEE, *supra* note 47.

tical in all relevant dimensions, statistical analysis can help to develop relationships to normalize different units and make reasonably good comparisons.

For example, we have elsewhere estimated relationships for the heat rates and availability of coal-fired generating units.⁸⁴ While we can identify several exogenous variables that help determine year-to-year variations in generating unit performance, over half of the observed variation in performance is unexplained. Much of this is simply random variation in year-to-year performance due to scheduled and forced outages, changes in output and system operating modes, and other factors. But even if these factors could be measured and controlled, considerable uncertainty about the optimal performance level for any specific unit would remain.

All of this argues that rewards and penalties should not be too drastic, since they will inevitably be based on imperfect standards. A performance target could be established based on the characteristics of an individual unit and penalties assessed or rewards given (via changes in rates) based on deviations between target and actual performance. These penalties should be set equal to a fraction of the cost changes due to departures from the norms. As we shall see below, several incentive schemes of this type are now in effect.

The major concern with regulators setting specific performance targets is that firms will be induced to make excessive expenditures to improve measured performance. By spending more on maintenance and using higher quality (and more expensive) fuel, utilities can generally improve availability and heat rates. But the expenses may be greater than the savings. If expenses incurred to improve performance in these dimensions are given standard cost-of-service treatment in rate-making, while improvements in performance are rewarded, serious distortions could result.

B. *Recent Agency Activity on the Incentive Regulation Front*

As of January 1, 1986, thirty-one incentive programs in operation in twenty states, as well as FERC, incorporated at least some of the incentive payment concepts discussed above.⁸⁵ The Appendix summarizes the results of a recent survey of state commission activity on the incentive regulation front conducted by John Landon for National Economic Research Associates, Inc.⁸⁶ We include only those programs that reflect at least

84. P. JOSKOW & R. SCHMALENSSEE, *supra* note 47.

85. See J. LANDON, *supra* note 1. State commissions sometimes refer to certain regulatory actions as embodying incentive regulation, even though the measures are in fact merely traditional prudence reviews of one sort or another that reward or penalize a particular utility after the fact. These types of regulatory action are not incentive regulation as that term is used in this Article.

86. J. LANDON, *supra*, note 1. The Appendix also reflects updates through August 1986 of the

some *ex ante* decoupling of prices from costs and have excluded more traditional *ex post* prudence/efficiency reviews, even if they can in principle lead to rewards as well as penalties for the utilities affected. The Appendix includes programs that are currently operating, programs pending commission decisions, and programs that have been recently discontinued. The programs that we feel can reasonably be categorized as reflecting the incentive payment concepts discussed in this Article break down roughly into the following categories:⁸⁷

<i>Type of Program</i>	<i>Number of Programs</i>
Generating Unit Capacity Factor/ Availability	15
Generating Unit Heat Rate	7
Fuel Cost Related Incentives	8
Construction Cost Caps	3
Overall Cost/Efficiency	1
Non-Fuel O & M Costs	1
Other	1

It is useful to discuss a few examples of specific incentive payment mechanisms that have been tried by state commissions.⁸⁸

1. *Generating Unit Capacity Factor/Availability*

In November 1984, the Arizona Corporation Commission initiated an incentive program targeted at the performance of the Arizona Public Service Company's generating units.⁸⁹ For the company's nuclear plant, Palo Verde 1, the performance target is the plant's capacity factor: the actual amount of electricity generated divided by the amount of electricity that could be produced if the plant operated continuously throughout the year. Since the running costs of a nuclear unit are low relative to the running costs of fossil-fueled units, a nuclear unit would ideally be run all the time. Planned maintenance and forced outages obviously make a 100% capacity factor unattainable, but the idea is to encourage the utility to keep the plant up and running as much as is economically feasible. The incentive provision establishes a "dead band" for the unit's capacity factor between 60% and 75%. This is the performance "norm" for the unit. If

survey by Landon (personal communication with the authors).

87. The number of programs totals to more than 31 because several programs use more than one performance norm.

88. This discussion is based primarily on trade press reports, Commission Orders, and the descriptive material contained in J. LANDON, *supra* note 1, and L. JOHNSON, *supra* note 68.

89. Ariz. Corp. Comm'n, Opinion and Order, Phase II, Docket No. U-1345-83-155, November 28, 1984. This program is under review in a current docket.

the unit achieves a capacity factor within this band, there are no special rewards or penalties. Capacity factors between 75% and 85% yield a reward to the company equal to 50% of the fuel cost savings resulting from running this plant more, and more costly plants less. Capacity factors above 85% yield a reward equal to 100% of the resulting fuel cost savings. Conversely, capacity factors between 50% and 60% result in a penalty equal to 50% of the additional fuel costs incurred by falling below the normal range. If the capacity factor falls to the 35% to 50% range, the penalty is equal to all of the additional fuel costs incurred. Capacity factors below 35% trigger a Commission reevaluation of the rate base treatment for Palo Verde.

The commission initiated a related incentive mechanism for Arizona Public Service's coal units located at the Four Corners generating station. Rather than using capacity factor as the norm, the unit's equivalent availability factor (EAF) is used.⁹⁰ The Four Corners units are relatively low cost generating resources and as the amount of time they are available increases, on average, the lower will be the total costs of generation. The structure of the incentive provisions based on the EAF performance standard is very similar to that for the Palo Verde nuclear unit.⁹¹

2. *Generating Unit Heat Rates*

The heat rate of a generating unit measures the quantity of fuel (in btu's) required to generate a kwh of electricity. The lower the heat rate, the more efficient a generating unit is in transforming fuel into electricity and, other things equal, the lower is the cost of electricity.⁹² A few states have applied incentive payments to the heat rate achieved by one or more generating units, either separately or in addition to EAF incentives.

In 1981 the California Public Utilities Commission initiated an incentive payment program applicable to four coal-fired generating units in which Southern California Edison Company had an ownership interest or which the utility operated.⁹³ The program establishes targets for both the capacity factors of the units and their heat rates. The capacity factor benchmark is a four year average of each unit's gross capacity factor. The heat rate benchmark is an annual average of the gross heat rate for each unit. A "dead band" for each is established based on plus or minus 50% probability limits around the benchmarks. Performance outside this band

90. For a definition of the EAF, see *supra* note 83.

91. For detailed discussion of this incentive program, see L. JOHNSON, *supra* note 68, at vii-ix.

92. There is no simple meaningful measure of the heat rate of a nuclear unit.

93. Cal. Pub. Util. Comm'n Decision No. 93,363, July 22, 1981. This program is currently being reevaluated to determine if the 1981 benchmarks should be adjusted.

yields penalties for poorer performance and rewards for better performance. The penalties and rewards are based on fuel cost increases or decreases, and there is a cap on both.

3. *Fuel and Purchased Power Cost Incentives*

In 1983 the New York Public Service Commission initiated an incentive payment program designed to encourage utilities to minimize fuel and purchased power costs.⁹⁴ The program currently applies to two utilities in New York, but it may be extended to others. The utilities are required to make forecasts of their expected fuel cost for a year into the future. These predicted costs are included in the rates. Differences between actual fuel costs and forecast fuel costs are shared between the utility and its customers; electricity rates are changed to recover 80% of the difference, and the utility bears the remaining 20%. The program includes a cap on the amount of the utility's penalty or reward. Once the year-to-date deviation between forecast fuel costs and actual fuel costs reaches \$50 million, the share of additional deviations passed through as increases or decreases in rates increases to 90%—in other words, the utility's share falls to 10%. When the year-to-date deviation reaches \$100 million, the adjustment mechanism reverts to a full fuel cost pass through. This provision effectively places an annual \$15 million cap on the rewards or penalties that the firm can bear.⁹⁵

4. *Construction Cost Incentives*

Several states have recently introduced programs which specify target construction costs for completion of unfinished nuclear plants. These programs typically emerge in the context of commission review of the desirability of finishing particular plants, and they are not intended to be permanent additions to the regulatory regime.

In 1983 the New Jersey Board of Public Utilities instituted an agreement with Jersey Central Power & Light Company providing for the control of construction costs for the Hope Creek nuclear plant.⁹⁶ If construction costs exceed \$3.79 billion, the company may recover only 80% of costs up to 110% of the target cost of construction, and only 70% of those

94. *In re* Rochester Gas and Electric Corp., 68 Pub. Util. Rep. 4th (PUR) 289, 312-15 (N.Y.P.S.C. 1985); *In re* Niagara Mohawk Power Corp., 56 Pub. Util. Rep. 4th (PUR) 315 (N.Y.P.S.C. 1983).

95. In the context of equation (4), this sort of scheme amounts to increasing the value of the sharing coefficient, g , the larger the absolute value of the difference between actual and projected costs. This is a sensible general approach, since huge differences between forecasts and realizations are likely to be disproportionately determined by random events beyond the utility's control.

96. N.J. Bd. Pub. Util. Decision and Order, Docket No. 8012-914-IPRRA, Aug. 12, 1983.

in excess of 110% of the target cost of construction. If construction costs are less than \$3.55 billion, then the company is allowed to retain 20% of the savings. No reward or penalty is allowed if construction costs fall within a "dead band" range of \$3.55 to \$3.79 billion.

The New York Commission has initiated similar arrangements for specific nuclear plants. Several other state commissions, including those in Arizona, Connecticut, Pennsylvania, and Illinois, have placed construction cost caps on nuclear plants which carry the implication that all costs in excess of this cap will be presumed to have been imprudently incurred.⁹⁷

5. Overall Costs

In July 1983 the Utah Public Service Commission initiated a comprehensive incentive program to be applied to Utah Power & Light Company. This "Total Factor Productivity Cost Factoring Program" used a four-part regression model derived from the company's own historical experience to estimate expected annual costs. Power production expenses, operating and maintenance expenses, capital investment in generating plants, and capital investment in transmission and distribution facilities were computed from time-series regression equations to arrive at an "expected cost" figure and a band of "normal" fluctuations, and the estimated costs were compared with the actual costs incurred by the utility. The company and its customers shared equally in any cost difference if actual costs were less than expected costs. No formal penalty (aside from regulatory lag) was imposed if the utility's actual costs exceeded its expected costs. The commission was forced to abandon the program in 1984 following uncertainty over the legality of incentive regulation programs under Utah law.⁹⁸

97. *In re* Ariz. Pub. Serv. Co., 64 Pub. Util. Rep. 4th (PUR) 147 (Ariz. C.C. 1985); *In re* Clinton Unit #1, Ill. Com. Comm'n Docket No. 84-0055, 1985; *In re* Limerick Unit No. 2 Nuclear Generating Station, Penn. Pub. Util. Comm'n Order No. I-840381, 1985; *In re* Nine Mile Point No. 2 Nuclear Station, 62 Pub. Util. Rep. 4th (PUR) 455 (N.Y.P.S.C. 1984); *In re* Seabrook Unit No. 1, 62 Pub. Util. Rep. 4th (PUR) 673 (Conn. Dep't of Pub. Util. Control 1984). We have not included the straight nuclear construction cost caps in the survey of incentive regulation programs in the Appendix, but this is mainly a matter of taste.

98. The Utah Public Service Commission worked for three years to develop an incentive program for utilities in that state. The report on this program was presented to the commission in the summer of 1983. Several public interest groups protested what they regarded as "rewarding utilities for doing their job." Due to public opposition to the incentive program, the Utah Public Service Commission requested that the Utah legislature pass a bill granting clear legal authority for incentive regulation programs. The proposed bill died in committee and has not been resurrected. The incentive program is still sitting on the desk of the Utah Public Service Commission pending further legal developments. Telephone interview with Ken Powell, Manager of the Electric Section, Utah Public Service Commission (Oct. 7, 1986).

6. *Rate Indexing*

We are not aware of any comprehensive rate indexing proposals that have been implemented as of January 1, 1986.⁹⁹ The only program that comes close is one which operated in Michigan from 1979 until 1983.¹⁰⁰ Even this program covered only operating and maintenance expenses other than fuel and purchased power.¹⁰¹ Under this program, the utility determined a base level of covered expenses which was then indexed to the Consumer Price Index. If actual expenses increased more slowly than the CPI, the company was permitted to keep the difference. On the other hand, if expenses increased faster than the CPI, the company could recover none of the difference between actual and indexed expenses. This program was discontinued in May 1983.

Conclusion

The preceding overview of current state commission efforts in the incentive regulation area shows a growing awareness of the desirability of at least partially decoupling prices or revenues from the actual costs incurred by regulated monopoly electric utilities. But the actual extent of decoupling in practice seems to have been arbitrarily determined. Often regulators also appear to recognize that a good incentive scheme involves both applying penalties for performance below the norm and allowing rewards for superior performance. But regulators have avoided comprehensive cost adjustment programs, focusing instead on individual components of utility costs rather than on total costs. Indeed, most commission efforts have been directed toward generating unit performance and fuel and purchased power costs, behavior which determines the costs of generating electricity from existing plants. Comprehensive partial cost adjustment schemes and indexing schemes have been discussed extensively, but are not yet widely used. There is even less enthusiasm for comprehensive yardstick schemes.

While it is easy to criticize agency efforts in this area, it is also easy to understand why commissions have proceeded as they have. In the short and medium run, the costs of generating electricity from existing plants

99. A program approved by the Mississippi Commission as this Article was being written has indexing components as well as specific incentive provisions. See *PSC to Link Mississippi Power's Return to "Benchmark" Return, Performance*, *ELECTRIC UTIL. WEEK*, Aug. 18, 1986, at 1. This program was temporarily suspended when it was found to imply a rate increase. See *Miss. Power Performance Plan Indicates 2% Rate Hike—So PSC Suspends It*, *ELECTRIC UTIL. WEEK*, Sept. 8, 1986, at 7.

100. See Mich. Pub. Serv. Comm'n Order U-5502 (1978).

101. On average these expenses account for 15% to 20% of the price of electricity. *EDISON ELEC. INST.*, *supra* note 7, at tables 71 and 72.

and of purchasing energy and capacity present the major opportunities for reducing costs. Commissions cannot do much about the generating capacity that is in place, nor about capacity already in the pipeline. In a few states, incentive payments have been tied to the costs of completing nuclear plants, but in most cases the costs of major new generating facilities are evaluated through prudence reviews. In any event, few if any new major generating plants are currently being planned by U.S. electric utilities.¹⁰²

Moreover, focusing on operating costs and generating unit performance avoids many of the problems inherent in applying comprehensive adjustment schemes in the real world—problems of utility cost accounting, inflation, lumpy investments, multiple technologies, and uncertain demand, input prices, and technical progress. The shortcomings of regulatory accounting systems are such that incentives for minimizing accounting capital costs might well produce perverse investment decisions. Commissions focus on the operating characteristics of existing plants that can be measured in physical terms rather than in dollars. This makes implementation of partial yardstick approaches limited to specific measures of operating performance quite feasible given available data and econometric techniques. The extensive amount of information on generating unit performance over time and space makes it relatively easy to use modern econometric techniques to establish reasonably good performance norms and to develop good information about the stochastic properties of generating unit performance.¹⁰³ Fuel cost control does not involve complicated capital cost accounting problems. Finally, although as yet untried, a combination of indexed fuel-related costs and partial cost adjustment—perhaps based on statistically established performance standards—could be used to set standards for fuel costs.

We do have a number of concerns, however, about the sorts of incentive programs that have been widely employed to date. We are concerned that by focusing on generating unit performance rather than on a more comprehensive measure of total generating costs, utilities will be induced to make excessive expenditures on maintenance and capital improvements to improve their scores on these norms. This narrow definition of performance may also distort decisions to purchase power from others or to generate power for resale to others. We also do not believe that the incentive payment programs targeted at fuel and purchased power costs have been

102. See *Report Shows Dramatic Dropoff In New Plant Additions Beginning in 1988*, *ELECTRIC UTIL. WEEK*, Aug. 18, 1986, at 4.

103. That is, both to establish expected or average performance and to describe the likely variation in performance due to unmeasured random influences.

structured properly. Fuel costs have moved up and down significantly in the past decade with major changes in energy market conditions. Nobody has been able to forecast these changes with consistent accuracy. It accordingly makes little sense to us to require a utility to predict its nominal fuel costs a year or more into the future, and then to make incentive payments in the form of rate changes based on departures from the predicted values. Too much of the difference between actual and predicted costs will be due to factors over which management has no control.

Rather than having utilities make predictions of nominal fuel costs, it would be better to have utilities predict real fuel consumption (in tons of coal and barrels of oil, for instance) at different output levels. These predictions could be evaluated relatively easily by regulators in light of historical experience. Acceptable fuel use predictions could then be mechanically combined with fuel price indices to yield a cost function, as in equation (5), applying only to fuel. This function could then be used to adjust rates in response to changes in fuel and purchased power costs. In principle this approach could be extended to base fuel use predictions at different output levels on yardstick standards for efficient operation of each of the utility's generating units.

More generally, regulators should attempt to develop incentive payment mechanisms for non-fuel generating expenses, including labor costs. Cost norms based on the statistical yardstick notion could be developed by applying econometric techniques to data on hundreds of plants and utilities, along with indices of local wages and raw materials prices; such norms could be used as the basis for incentive payments. This type of approach could be incorporated with performance norms and fuel price norms to provide a more comprehensive incentive system that operates on total generating costs, exclusive of capital costs.¹⁰⁴ The remaining costs subject to control in the short run are operating and maintenance expenses at the transmission, distribution, and customer service levels. At the very least, this seems to be an area in which statistical yardstick techniques could be used to establish norms for labor hour requirements, and wage indices could be applied to these norms to establish cost targets on which incentive payments would be made. On the other hand, it is important to factor in service quality in such incentive schemes, since cuts in distribution costs that are unaccompanied by increases in efficiency will simply produce more outages.¹⁰⁵

104. While we are convinced that this approach is both desirable and feasible, the requisite statistical studies have not yet been done. We should also note that the inclusion of purchased power costs in such a comprehensive program poses a number of practical problems that also have not yet been systematically addressed.

105. Again, the requisite studies apparently have not been undertaken yet, and it is not clear

In short, as far as operating costs go, the challenge is to develop a set of cost functions, like C^* in equation (5), for major components of utility operating costs and to provide for some sharing of deviations of costs from target levels between the utility and its customers; that is, to extend what has already been done for generating unit performance and fuel costs individually. While we are optimistic that such functions can be developed, we doubt that either theoretical advances or available information will lead to clear methods for determining the optimal "sharing fraction" (corresponding to g in equations (4) and (4')) in these or any other schemes.

If recent theoretical work has taught us anything, it is that the problem of determining the optimal sharing fraction is just too complex in principle to be readily soluble in practice. As a practical matter, commissions should establish sharing fractions which (a) are not likely to have a significant effect on the regulated firm's systematic risk (so the cost of capital will not change dramatically); and (b) place "credible" bounds *ex ante* on rewards and penalties, recognizing that enormous penalties or rewards will not be sustained. These pragmatic considerations imply that incentive regulation schemes should be designed using utility-specific simulation models so as to produce "reasonable" financial outcomes under plausible scenarios about the near term future. These considerations also suggest that regulation should not move sharply away from cost-plus toward fixed-price arrangements,¹⁰⁶ since the latter carry with them a substantial risk of unacceptable outcomes. We also note that it is generally desirable to weaken incentives and move toward cost-plus arrangements as economic and technological uncertainty increases.

We do not advocate extending incentive regulation beyond operating and maintenance costs. Trying to incorporate major capital investment decisions into these types of indexed/partial adjustment systems seems hopeless. The capital accounting problems are simply too severe. We are attracted instead to one of two strategies for major capital expenditures, particularly generating plants. First, more systematic prudence reviews of construction costs should be developed. These might involve statistical yardstick comparisons with costs elsewhere.¹⁰⁷ Second, serious consideration should be given to moving toward a competitive bidding/contracting process for new generating capacity, as has been suggested in Massachu-

precisely how service quality issues can best be handled.

106. This would mean moving toward very low values of parameters such as g in equations (4) and (4').

107. See, e.g., Joskow & Rose, *supra* note 83, at 21. While reported capital costs of existing plants mainly reflect accounting conventions, the actual construction costs of new facilities can be usefully compared across firms and over time.

setts,¹⁰⁸ although care must be taken to preserve economies that may be inherent in having utilities integrated into the architect/engineering function.¹⁰⁹ In any event, regulating construction costs does not appear to be a particularly high priority item, since utilities are planning to add little new generating capacity over the next ten years beyond the few remaining nuclear plants now nearing completion.

In incentive regulation, as in many other policy areas, good intentions are necessary but not sufficient for good results. State commissions cannot be taken to task for lack of good intentions. Nor can they be faulted for failing to follow the prescriptions of recent theoretical work, since that work provides little in the way of specific guidance. But we do think that basic economic analysis should be used with more care in the design of incentive schemes, and available data and econometric techniques should be more fully exploited to develop cost and performance standards. Incentive regulation cannot dramatically enhance the performance of electric utilities. It *can* produce some improvement if—and perhaps only if—it is done well.

108. Mass. Dept. Pub. Util. Order and Notice of Proposed Regulations, D.P.U. 84-276-A, Feb. 3, 1986.

109. See, e.g., Joskow & Rose, *supra* note 83, at 28-29, and P. JOSKOW & R. SCHMALENSEE, *supra* note 47. It also remains to be seen if it is possible to make simple, straightforward comparisons of competing bids.

APPENDIX

Incentive Regulation Programs By State

<u>State</u>	<u>Companies</u>	<u>Type of Program</u>	<u>Date Initiated</u>
Arizona	Arizona Public Service	Capacity Factor Equivalent Availability	1984
Arizona	Arizona Public Service	Construction Cost Cap on Nuclear Unit	1984
Arkansas	Arkansas Power & Light	Capacity Factor	1981
California	Southern California Edison	Capacity Factor, Heat Rate	1981
California	San Diego Gas & Electric Southern California Edison	Capacity Factor	1983
California	Pacific Gas & Electric Southern California Edison Sierra Pacific Power San Diego Gas and Electric	Fuel and Purchased Power Costs	1983
Colorado	Public Service Company of Colorado	Capacity Factor	1983
Connecticut	Connecticut Light & Power	Capacity Factor	1979
Delaware	Delmarva Power & Light	Capacity Factor Equivalent Availability	1984 (proposed)
Florida	Florida Power and Light Florida Power Gulf Power Tampa Electric	Equivalent Availability Heat Rate	1980
Florida	Florida Power and Light	Capacity Factor	1983
Florida	Florida utilities	Economy Energy Sales	1984
Maryland	Maryland utilities	Equivalent Availability, Heat Rate	pending
Massachusetts	Boston Edison	Equivalent Availability, Heat Rate	1981;1983
Michigan	Michigan Utilities	Fuel and Purchased Power Costs	1979 ¹
Michigan	Consumers Power Detroit Edison	System Availability	NA ²
Michigan	Consumers Power	Operation and Maintenance Costs	1979 ²
New Hampshire	Public Service of New Hampshire	Generating Unit Availability	1982
New Jersey	Atlantic City Electric Jersey Central Power & Light Public Service Electric & Gas Rockland Electric	Fuel and Purchased Power Costs	1977
New Jersey	Jersey Central Power and Light	Construction Cost Cap For Nuclear Unit	1983
New York	New York State Electric & Gas Niagra Mohawk Power	Fuel and Purchased Power Costs	1983
New York	Consolidated Edison Orange and Rockland	Non-fuel Operation and Maintenance Costs	1983

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New York	Owners of Nine Mile Point Unit 2	Construction Cost Cap On Nuclear Unit	1984(?)
North Carolina	North Carolina utilities	Fuel and Purchased Power Costs	1983
Oregon	Portland General Electric	Fuel and Purchased Power Costs	1980
Pennsylvania	Pennsylvania utilities	Fuel and Purchased Power Costs	pending
Texas	Texas Utilities	Heat Rate Equivalent Availability	pending
Texas	Southwestern Public Service	Heat Rate	1984(?)
Utah	Utah Power & Light	Total Factor Productivity	1983 ^a
West Virginia	West Virginia utilities	Generation, transmission and distribution system performance	pending
FERC	Virginia Power	Heat Rate Equivalent Availability	1983

Source: Information drawn from a survey entitled "Incentive Regulation In The Electric Utility Industry," compiled by John Landon for National Economic Research Associates, Inc. in October 1985, as updated by personal communication, August 1986. The Landon survey lists a larger set of regulatory programs and prudence reviews than have been listed above. Many of these activities are not, in our opinion, in the "incentive regulation" spirit (whatever the regulators say) and we have not included them here.

1. Discontinued in 1983.
2. Discontinued in 1983 because of state regulations against automatic adjustments.
3. Discontinued in 1984 due to conflicts with state law.

