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REGULATORY PRACTICES AND INNOVATIVE GENERATION TECHNOLOGIES: PROBLEMS AND NEW RATE-MAKING APPROACHES

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EXECUTIVE SUMMARY

This report present the findings of a study funded by a grant from the United States Department of Energy. The study has two major objectives: (1) identify uneconomic barriers confronting electric producers with regard to the commercialization of innovative generation technologies (IGTs) currently in precommercial stages of development; and (2) develop new regulatory approaches to overcome such barriers.

The study identifies potential national and local benefits from commercial adoption of IGTs. They include better utilization of domestic energy resources, promotion of national energy security and independence, achievement of a cleaner environment, preservation and expansion of local and national job markets, and creation and expansion of export markets for IGTs and related technologies.

In spite of the many potential benefits of IGT commercialization, the study finds that market and institutional barriers may uneconomically inhibit the adoption of IGTs. The study observes that for the two major categories of potential IGT adopters, namely investor-owned electric utilities (IOUs) and nonutility generators (NUGs), different forms of barriers exist.

Investor-owned utilities, whose retail operations fall under the auspices of state public utility commissions, face barriers to IGT adoption that are inherent in the regulatory structure. The study identifies the asymmetry of the risk/reward structure in the current regulatory environment as the major impediment to risk-taking and innovation. Simply, the traditional regulatory paradigm as practiced during the last several years does not adequately compensate a firm for the risk-taking associated with IGTs. The above feature of state public regulation is likely to bias the technology choices of IOUs in favor of low-risk, conventional alternatives. The study finds that the risk/reward structure in an unregulated market is generally more symmetric than under regulation.

The study also finds that NUGs, whose profits are less constrained by regulation, confront different barriers to IGT adoption. It is observed that most NUGs are small and use highly leveraged debt financing to fund construction projects. Small asset bases of NUGs, relative to the size of the investment in a typical IGT project, require NUGs to obtain financing under tight restrictions. Debt financing, as is widely known, requires higher performance guarantees and is infrequently used to finance high-risk projects. An added obstacle to NUG generation arises from the fact that state regulators restrict a utility's incentive to purchase power. Giving utilities an opportunity to directly profit from economical power purchases would place power purchases on more equal ground with demand-side activities, for which utilities have increasingly been permitted to earn profits. The risk-averse character of utility managers, in addition to the risk-averting nature of regulation, may act as obstacles in the adoption of IGTs by nonutility generators. Therefore, although NUGs generally face a more favorable market environment than IOUs for innovation, they still suffer from certain obstacles.

The study concludes that the public benefits of IGTs, in addition to the asymmetric risk/reward problem, may warrant state regulatory commissions to offer incentives to overcome barriers to IGT adoption. The study recommends that such incentives should preserve traditional regulatory goals of protecting ratepayer interests and of ensuring cost-efficient and prudent management.

Finally, the study examines different regulatory approaches that could be applied to overcome barriers to economically desirable IGT adoption. The study finds that comprehensive incentive systems in a competitive or quasi-competitive environment are preferable to partial or targeted incentive systems. Partial schemes, however, may be easier to implement and more acceptable to state regulators in the near term. The study evaluates several comprehensive and partial systems including price caps, profit sharing, cost sharing, power plant performance incentives, and preapproved cost caps. As examples of comprehensive and partial incentive systems with desirable economic and regulatory attributes, the study develops and illustrates two incentive mechanisms: a utility-wide one founded on combined price-caps/profit-sharing principles, and a targeted one based on cost sharing of life cycle costs of IGTs. The study advises state regulatory commissions to explore and pursue incentive-based approaches aimed at promoting economical commercialization of IGTs.

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PREFACE

From time to time the NRRI does contract research for federal agencies in the energy field. The present report was performed under a grant from the U.S. Department of Energy through the Argonne National Laboratory. A major line of inquiry in the study is how regulatory authorities can facilitate, inhibit, or be neutral about the introduction of innovative generation technologies in electricity. Not surprisingly, considerable attention is given as to how uneconomic barriers can be reduced and facilitation enhanced.

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CHAPTER 1

INTRODUCTION

This study examines the presence of barriers to commercial adoption of emerging innovative generation technologies and develops approaches to overcome such barriers in a manner consistent with economic efficiency and the public interest.

The Setting

In response to growing concerns for energy security, energy efficiency, and environmental protection, a number of energy generation and pollution control technologies, and energy management options have emerged in the electric power industry over the last two decades. The technologies are intended to improve the efficiency of energy conversion from fossil fuels, reduce the levels of pollutant emissions, and better utilize nonfossil sources of energy, thus improving *generation efficiency*. The energy management options, better known as demand-side management (DSM) options, are intended to improve energy conversion in end-use appliances, minimize dissipative energy losses (for example, through better insulation), and modify diurnal and seasonal demand profiles to optimize energy usage patterns, thus improving *consumption efficiency*.

Also, many of these technologies and options achieve better pollution control in various ways. Greater energy efficiency itself reduces pollution by using a smaller amount of pollutant-emitting fuels and other materials per unit of energy generated or energy demand met. Additionally, many of these technologies are equipped with direct pollution control devices or have inherent characteristics that lead to lower emissions of pollutants.[1]

[1] For example, the fluidized bed combustion (FBC) technology of burning coal features a process of mixing coal, air, and a sulfur-absorbing agent that produces significantly less sulfur dioxide (SO_2) than conventional coal plants. Furthermore, the FBC process can be designed to burn coal at lower temperatures and reduce nitrogen oxide (NO_x) emissions.

Among the technologies and options mentioned, this report focuses on electric generation technologies that can potentially improve energy efficiency and pollution control over conventional technologies while achieving better utilization of domestic fuel and nonfuel resources.[2] These technologies are named innovative generation technologies (IGTs) and include clean coal technologies (CCTs) and advanced design nuclear reactors. Also included in this group of technologies are those that use renewable resources such as solar, geothermal, wind, and biomass. Significant amounts of effort and resources have been devoted to developing and demonstrating IGTs.[3] As several of the IGTs complete precommercial scientific development and become ready for commercial deployment during the next decade, they offer potentially more energy efficient and environmentally superior alternatives to conventional generation and pollution control technologies.

Completion of technological development alone, however, does not ensure that IGTs will be adopted for commercial deployment by investor-owned utilities (IOUs) and nonutility generators (NUGs). Like most technological innovations, IGTs carry the risks of technological and economic underperformance. Commercial deployment often involves an increase in size, compliance with local, state, and federal performance standards, integration with the rest of the utility system, or use of a technology which has been utilized only once or twice at the contemplated scale. A technology that appears feasible at the laboratory, the pilot, or the demonstration scale may not perform well enough to meet the needs of a commercial plant or of a commercial buyer. First, there may be unanticipated delays in initiating and completing construction, partly owing to the complex and long siting and certification process needed for new facilities and partly owing to inherent or unforeseeable technical problems germane to a new

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[2] Although the last decade witnessed an aggressive pursuit of DSM options to meet the goals of energy efficiency and environmental quality, significantly less attention has been devoted to energy generation and pollution control technologies that can potentially achieve the same goals.

[3] An overview and updated status report of the U.S. Department of Energy's efforts to develop CCTs is available in U.S. Department of Energy, *Clean Coal Technology Demonstration Program, Program Update 1992* (Washington, D.C.: U.S. Department of Energy, February 1993). The U.S. Department of Energy also conducts development programs for advanced nuclear and renewable technologies.

technology. Second, there may be construction cost overruns, partly caused by unanticipated construction delays and partly by unanticipated increases in the costs of materials and labor. Finally, a completed plant based on a new technology may not perform as expected and may incur operating costs that are higher than expected.

Because of the risks present in the adoption process, IGTs, which have been designed to perform more efficiently and at lower costs than conventional alternatives in the long run, may cost more in the short run during the earlier stages of commercial adoption. These higher costs, encountered in overcoming information barriers in adopting an innovation and known as "learning costs," fall on the potential adopter while the longer-term benefits of the innovation may accrue to society at large. The presence of this condition constitutes an economic externality and may inhibit IGT adoption and inefficiently distort generation technology choices in favor of conventional generation choices.[4]

Besides those mentioned in the foregoing discussion, there may be other impediments to IGT adoption faced by the potential adopters, IOUs and NUGs. These impediments may arise from both the characteristics of the innovating firm, and the market and the institutional environments in which the firm operates. For example, IOUs subject to economic regulation may face barriers to IGT adoption that arise from the asymmetric risk/reward structure offered by the regulatory arrangement. NUGs, which are not regulated and therefore do not face the same constraints to IGT adoption, nevertheless may face barriers of a different kind. Most NUGs have asset bases that are small relative to the size of the investment typically needed to adopt an IGT and generally have highly leveraged (high debt/equity ratio) capital structures. This makes it

[4] An economic externality may be defined as a cost for which an economic agent is not compensated or a benefit for which an economic agent does not pay.

extremely difficult for a NUG to obtain financing for a risky and high-capital-outlay project.[5]

As IGTs have potential longer-term benefits, it is important to identify uneconomic or inefficient barriers[6] to IGT adoption so that policies can be crafted to overcome these barriers. To commence an examination of barriers to IGT adoption and the related issue of technology choices faced by IOUs and NUGs, it may be helpful to review the historical evolution of the electric power industry. Such a review can also provide useful insights on the possible future course of the industry and serve as the broad context within which the issues of generating technology choices and IGT adoption are examined.

The Historical Context

By most indications, the electric power industry in the United States is poised for a period of rapid change during the 1990s and beyond. Three basic forces, namely energy efficiency, environmental control, and greater competition, that increasingly shaped the industry's course over the last two decades are also likely to drive its evolution in the next decade.

During the 1970s, the oil embargo imposed by OPEC (Organization of Petroleum Exporting Countries) led the West to realize the need for a lessened dependence on foreign sources of oil and a need for energy diversification. At that time, economic downturn at the national level (which was correlated with both the oil embargo and the related event of worldwide stagflation), the failure of electricity demand to grow at projected rates, and the end of an era of declining nominal electricity prices led electric utility regulators to escalate their levels of scrutiny and oversight of utility operations and investment decisions. The goal of the new regulatory regime came to be the achievement of greater efficiency in both the production and use of electricity. Beginning in the late 1970s and early 1980s, many commissions initiated utility

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[5] A more detailed examination of regulatory, financial, and other barriers to IGT adoption is presented in Chapters 3, 4, and 5.

[6] Any barrier to IGT adoption and for that matter, any constraint to an investment choice, may not be necessarily inefficient. It can be argued that some barriers to innovation may in fact act as protection against excessive risk-taking and poor investment choices.

resource planning policies that either favor conservation and other DSM options or require their use on an equal basis with the conventional supply side generation options.[7] The new approach to utility planning, with some variations, has since been known as least-cost utility planning (LCUP) or integrated resource planning (IRP). Currently, most commissions have policies that favor some form of IRP.

In a related development, the recognition of the need for national energy security as well as greater generation efficiency spurred the enactment of the Public Utilities Regulatory Policy Act (PURPA) of 1978, designed to promote greater use of more efficient, domestic and nonconventional sources for generating electricity. It required a utility to purchase power from cogenerators, small power producers (for example, renewables), and other qualifying facilities (QFs) when the price of purchased power was below the utility's own avoided cost. Independent power producers (IPPs), which can be characterized as nonfranchised utilities, were excluded from the provisions of PURPA. The primary rationale for enacting PURPA was that it would lead to greater and more efficient use of domestic and renewable resources, otherwise unutilized, to produce electricity and thereby lessen the nation's dependence on foreign oil.

In parallel with the movement toward greater energy efficiency, the period since 1969 also has witnessed a strong movement toward greater control of environmental pollution. This has been reflected in a number legislative acts at the federal level and aggressive environmental activism at the state and local levels. Starting with the National Environmental Policy Act of 1969 (NEPA) and the Clean Air Act of 1970 (CAA), the U.S. Congress enacted several pieces of major legislation that sought to limit pollutant emissions from electric power plants. The latest in the series was the Clean Air Act Amendments of 1990 (CAAA) which imposed strict limits on the emissions of SO_2, NO_x, and air toxics. During the same period, many states enacted legislation and strict compliance rules covering the siting of power plants and other facilities and the emission of pollutants.

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[7] Thirty-one states currently have regulatory incentives for DSM options in place or under development according to the National Association of Regulatory Utility Commissioners, Committee on Energy Conservation, *Incentives for Demand-Side Management* (Washington, D.C.: The National Association of Regulatory Utility Commissioners, January 1992).

The third major development in the electric utility industry is the movement toward greater competition in the power generation sector, which started with the creation of an industry of NUGs under PURPA. Recently, the enactment of the Energy Policy Act of 1992 (EPAct) allows utilities and non-PURPA generators to compete on a wider scale in the wholesale power market, which is currently being served mostly by regulated and franchised utilities. The move toward market-based approaches has also emerged in environmental legislation. The CAAA, for example, allows trading of SO_2 emission credits or allowances such that utilities with low pollution costs can overcomply and sell the excess pollution credits to other power producers that may choose to undercomply because of higher pollution control costs.

Each of the developments listed has significant implications for both IOUs and NUGs. On one hand, regulators continue to demand and enforce greater energy efficiency and environmental control from IOUs and NUGs. On the other hand, IOUs and NUGs are likely to see competitive markets emerge for both power and environmental tradeables.

It is not clear whether the interaction of an activist regulatory regime at the state level and market-based approaches initiated at the federal level will produce intended outcomes.[8] It cannot simply be claimed that these forces are necessarily at odds (just because one apparently constrains and the other fosters competition) since they affect

[8] The intended outcomes of both the recent regulatory activism of commissions and market-based approaches initiated at the federal level are arguably quite compatible. Both attempt to achieve the supply of electricity and environmental control at least cost with an efficient allocation of resources.

different aspects of a utility's operations and different segments of the power market. They do interact, however, and thereby influence how effectively each works. For example, the emergence of a marked competitive wholesale market for power depends on the extent to which commissions allow a utility discretion to purchase and sell in these markets. Similarly, a commission's objective of securing least-cost power for its jurisdictional customers can certainly be helped by the emergence of a workably competitive wholesale market. The same reasoning can be extended to the interplay between commission regulation and the emergence of a workable emissions allowance market. It is not clear how the future will evolve as a result of the interaction of these developments. It is clear, however, that emerging markets for both power and tradeable emissions will expand available options for utilities to meet both their power and environmental compliance requirements. In meeting these requirements, utilities also must meet the regulatory objectives and standards set by commissions. The utilities and, to a lesser extent NUGs, are confronted with a world of expanding opportunities and, at the same time, of increasingly stringent regulation. As a result, power producers' choices of generation technologies, fuels, and operating strategies are likely to become increasingly complex. These observations provide the broad context for examining how these choices are affected by the current regulatory and market environments.

Organization of the Study

The study conducts a detailed examination of regulatory and market factors that affect the technology choices made by IOUs and NUGs. The examination focuses on the risk/reward structure offered by economic regulation to IOUs and how such a structure may influence risk-taking behavior of utilities. The study also examines how the financing arrangements and contractual obligations of NUGs influence their risk-taking behavior. The study identifies the long-term benefits of IGTs and how various local and national interests can be served by commercialization of IGTs. The study then develops a rationale for removing regulatory disincentives to IGT commercialization given the information externalities associated with IGTs. The study evaluates possible incentive approaches on the basis of a number of regulatory standards and objectives. The study also develops and numerically illustrates two selected incentive mechanisms.

The remaining chapters are organized as follows. Chapter 2 presents a background discussion of issues important to an examination of generating technology choices. Chapter 3 provides a capital markets' perspective on risky technologies. It asserts that the riskiness of a technology, *per se*, is not relevant to investment choices made by capital markets because the risk is often diversifiable but limits on earnings may act as a much more important decision parameter. Also, the utility management may have a different perspective from the capital markets and may still avoid adoption of risky technologies. Chapter 4 offers a detailed theoretical examination of the effect of stylized economic regulation on the adoption of IGTs by IOUs. The general features of regulation, such as bounds on earnings, and retrospective disallowances, are examined. This is followed by an examination of emerging industry and regulatory trends that may affect adoption of IGTs. Chapter 5 offers a detailed examination of issues that affect NUGs, particularly their technology choices. Chapter 6 discusses the rationale for developing and implementing regulatory incentive policies that may affect technology choices of IOUs directly and NUGs indirectly. Chapter 7 evaluates various incentive approaches and policies. Chapter 8 develops and provides a numerical illustration of two selected incentive mechanisms. Finally, Chapter 9 summarizes the findings of the study.

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CHAPTER 2

GENERATING TECHNOLOGY CHOICES AND THEIR IMPLICATIONS

Current Status of Electric Generation Technologies

In 1991, the net generation of electricity in the United States was 2,823,025 million kilowatthours (kWh). Coal had the highest share of this generation at approximately 54.9 percent followed by nuclear and hydro at 21.7 percent and 9.8 percent, respectively. The contributions of natural gas, oil, and renewables other than hydro were 9.6 percent, 3.9 percent, and 0.3 percent, respectively.[1] The total generating capacity was 739,957 megawatts of which coal-fired plants shared 43 percent. Nuclear, hydro, natural gas, oil, and renewables other than hydro shared 14 percent, 13 percent, 18 percent, 10 percent, and 1 percent of total capacity, respectively (Figure 2-1).[2]

Coal, which dominates the current mix of generation technologies, has the longest operating history. The typical standard, new coal plant has a thermal efficiency of about 35 percent, has a capacity of about 500 megawatts, costs about $1,500 per kilowatt and can supply electricity at a levelized cost of about 7 cents per kWh over its lifetime.[3] Conventional coal-fired plants, however, generate a number of pollutants harmful to the environment. They include SO_2, NO_x, and other atmospheric pollutants (that have been implicated as agents that contribute to acid rain and global warming), dry ash and other solid wastes stored in land fills, and liquid wastes that need to be processed before

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[1] The percentages may not add up to a total of 100 percent due to rounding. The data are derived from Energy Information Administration, *Monthly Energy Review* (Washington, D.C.: Energy Information Administration, June 1992).

[2] The capacity data represent nameplate ratings and are derived from Energy Information Administration, *Inventory of Power Plants in the United States* (Washington, D.C.: Energy Information Administration, October 1992).

[3] See Appendix A for cost data on coal-fired plants.

Notes: "Other" includes geothermal, refuse, steam, solar, waste heat, wind, and wood. Total may not equal the sum of components because of independent rounding.

Fig. 2-1. Percent of generating capability by energy source, as of December 31, 1991 (Source: Energy Information Administration, *Inventory of Power Plants in the United States 1991* DOE/EIA-0095(91) (Washington, D.C.: U.S. Government Printing Office, 1991), 5).

disposal. Newer coal plants, especially with the Clean Air Act Amendments of 1990 (CAAA) in force, are far cleaner in many respects.

In response to the tightening of environmental regulations over the last two decades, a number of older plants and all new plants currently use scrubbers to reduce SO_2 emissions, low-NO_x burners to reduce NO_x emissions, and other devices to reduce solid and liquid waste production. Other options currently available to control pollutant emissions from older plants include use of low-sulfur coals and precombustion cleaning of coal. For newer coal-fired generation, clean coal technologies (CCTs) offer promising options for cleaner and more efficient power production.

Nuclear power has been a significant contributor to the country's generation mix, accounting for about 21 percent of the total power produced in 1991. New nuclear plants have not been ordered since 1979. Historically, the typical nuclear plant cost in excess of $3,000 per kilowatt to build and has a levelized life-time cost of about 8.5 cents per kWh.[4,5] During its development, nuclear generation technology was perceived as a low-cost and nonpolluting source of power and indeed, early commercial units in service by 1975 often provide low-cost power today. In later years, however, both its perceived safety problems and cost increasingly became subjects of public suspicion and debate. A number of factors contributed to this development. They include the negative public perception associated with nuclear technology in general, the active role played by public interveners, and in many cases, poor management exercised by

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[4] The average cost for thirty-four nuclear projects was $3,123 per kilowatt including interest costs in nominal dollar, according to C. Komanoff, "Assessing the High Costs of New Nuclear Power Plants," *Public Utilities Fortnightly* 114, no. 8 (1984): 33-38. The levelized cost figure is quoted from Richard J. Gilbert, *Regulatory Choices* (Berkeley, CA: University of California Press, 1991), 270. The levelized life-time cost is estimated based on an assumed capital cost value of $3,000 per kilowatt and operating cost data reported in U.S. Department of Energy, *National Energy Strategy, Technical Annex 2* (Washington, D.C.: U.S. Department of Energy, 1990), 92.

[5] The average generating cost (including capital related charges) of coal plants in 1990 was 3.04 cents per kWh and for nuclear plants was 5.97 cents per kWh. See Energy Information Administration, *Electric Plant Cost and Power Production Expenses 1990* (Washington, D.C.: Energy Information Administration, June 1992), 14.

utilities. The outcome included a general proliferation of safety regulations, long delays in the certification and construction processes, and a rapid escalation of construction costs. About the same time that U.S. utilities began construction of a large number of nuclear power plants, the state of the world economy further exacerbated the fate of the nuclear option by causing a rapid escalation of fuel and operating costs. Thus, nuclear power, which was once thought to be "too cheap to meter" turned out to be among the more expensive generating options. The result included retrospective disallowances by commissions, significantly delayed construction, and the abandonment of several plants.

In spite of the negative perception associated with conventional nuclear plants, they may in many respects still be environmentally superior to most fossil-based plants. Their emission of pollutants is minuscule, except in the event of a major malfunction or accident which has an extremely low probability. Another major problem confronts the nuclear industry, however. It is the unresolved issue of the disposal of high level radioactive waste currently stored on site. The country as a whole has been unable to come to a consensus on choosing a site to be used as a repository of nuclear waste. No state wishes to shoulder the responsibility of being the repository of a massive amount of nuclear waste and face the risk of what is perceived to be a major disaster that could be caused by a breach of integrity in the repository.

In light of above observations, the future of the nuclear option appears uncertain. Support provided in the Energy Policy Act of 1992 (EPAct), however, may help the nuclear option regain its place as a viable component of the nation's future energy mix.[6]

Once a main source of base-load electricity, oil-fired generators have traditionally been used to supply peak demand because of the high unit cost of fuel. Oil-fired generation, like coal, will have to meet a number of emission reduction standards under the CAAA. Chief among these are limits on SO_2 and NO_x emission. Given the generally lower cost of natural gas and the less expensive pollution controls needed for natural-gas-fired units, oil-fired capacity is likely to be refueled with natural gas in areas where natural gas is available to utilities.

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[6] EPAct expedites the site characterization process of the Yucca Mountain as the future high level waste repository, streamlines the nuclear plant licensing process, and establishes funding support for the development of advanced nuclear concepts.

Like oil-fired generators, gas-fired generators are primarily used to serve peak and intermediate load. Generally, gas emits fewer pollutants than coal or oil. Because of the relatively low prices enjoyed over the last several years and its favorable environmental characteristics, gas is increasingly becoming a fuel of choice for electricity generation. One concept that is gaining popularity is gas cofiring with coal in existing coal units, which can be used for base-load plants as well. One concern that may impede widespread use of gas is the uncertainty of future production, prices, and delivery.

Solar electricity is produced by concentrating sunlight on reflective surfaces and converting the resulting thermal or light energy to electricity by using well-known thermodynamic or photovoltaic processes. Because of the seasonal and geographical dependence of this renewable energy source, it has been primarily used in the western and southern part of the country and is most productive during those times of the year when warm and sunny weather prevails. Solar energy comes in two forms, namely solar thermal and photovoltaic. Solar thermal energy is the direct collection of solar energy for space-heating purposes or the concentration of sunlight on a control collector to produce steam, which is then used to generate electricity. Photovoltaics, on the other hand, collect sunlight and convert it directly to electric current. Solar energy, like other renewables, is generally environmentally superior to both fossil-based and nuclear energy. Its main disadvantages lie in its high capital cost and low dispatchability. Solar energy contributed a fraction of a percent of total generation in 1991.[7]

Like solar, geothermal energy is another renewable option with desirable environmental characteristics. Also like solar, geothermal requires high capital costs. The most common form of geothermal technology, known as hydrothermal, uses hot steam found underground to directly run electrical turbines.

Like solar and geothermal energy, wind energy is another renewable option with high capital costs, low dispatchability, and minimal desirable environmental features. Wind energy, however, has a longer history of use than either solar or geothermal. Like solar but unlike geothermal, it has a strong dependence on weather conditions. Since wind energy plants operate

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[7] Energy Information Administration, *Monthly Energy Review*.

best on windy days and in suitable locations, their use has been limited to certain parts of the country and to favorable weather conditions.

Biomass from animal and plant waste has also been used as a renewable source of electricity generation. Biomass resources include wood and wood wastes, municipal solid wastes, industrial solid wastes, and agricultural residues.

Innovative Generation Technologies

In response to the growing need for environmentally superior energy generation, a number of technologies have appeared over the last decade. Most of these technologies have been developed at the initiative of or with substantial aid from the U.S. Department of Energy (DOE). While DOE provides the bulk of the research development costs of these projects, they are being cofunded by utilities, vendors, and others. The innovative generation technologies (IGTs) that have been under development include CCTs, advanced nuclear designs, advanced solar, geothermal, and wind technologies. The following presents brief summaries of IGTs. More detailed technical descriptions are given in Appendix A.

Clean Coal Technologies

CCTs include advanced methods for removing pollutants during the combustion process, advanced scrubbers or in-duct technologies that produce much lower levels of NO_x and solid and liquid wastes besides removing SO_2, and advanced precombustion cleaning of coal. Other methods include coal conversion, such as gasification and liquefaction of coal for cleaner combustion, and processes that do not require combustion of coal such as advanced coal cleaning. Among the more well-known CCTs are fluidized bed combustors, slagging combustors, in-duct sorbent injection, and integrated gasification combined cycle.

Advanced Nuclear Technologies

In response to public concern about the safety and operating efficiency of conventional nuclear plants, new design concepts are being pursued by several U.S. and international vendors. The advanced designs can be divided into three types. The first two are called advanced light water reactors (ALWR), which attempt to enhance the operating and safety features of light water reactors (LWR) traditionally used in the United States. The third type of design attempts to improve the operating efficiency and safety features of reactors that use liquid metals or gas as the coolant rather than water which is used in LWRs. With further development, ALWRs may become economically competitive with fossil-based generation while eliminating the need for extensive pollution control devices typically used in fossil plants.

Advanced Renewable Technologies

Research, development, and demonstration projects are underway to improve the economy and viability of environmentally benign renewable technologies. Research efforts are dedicated to finding better materials to achieve improved energy conversion efficiencies, to developing central-station-type applications for dispersed technologies, to integrating dispersed units with utility systems, and to developing energy storage technologies to improve the dispatchability of renewables.

Generating Technology Choices and Future Energy Needs

Based on one projection, the demand for electricity in the United States is likely to grow by 1.8 percent to 2.2 percent annually between 1990 and 2010. The need for new capacity is likely to grow between 1.1 percent and 1.4 percent annually during the same period.[8]

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[8] Energy Information Administration, *Annual Energy Outlook, With Projections to 2010*, DOE/EIA-0383(92) (Washington, D.C.: Energy Information Administration, 1992), 37.

By the year 2000, there will be significant need for new capacity in many parts of the country. At this time, many of the IGTs, especially CCTs, may reach commercial readiness and will compete with conventional generation technologies (CGTs). Their adoption, however, will depend on many factors, importantly regulation as discussed in subsequent sections. There will be very little need for building new base-load plants. Also, additional energy needs are likely to be met by gas-fired peakers, especially since gas prices have remained stable at low prices for some time and this trend is likely to continue into the near future. Gas may become the fuel of choice (Figure 2-2) also because of its desirable environmental features. Another option that will be increasingly used is the cofiring of coal plants with natural gas to satisfy base and intermediate loads.

Generating Technology Choices and Environmental Requirements

As discussed, both environmental protection and energy efficiency have been and are likely to continue as important vehicles that drive state and federal regulation of electric utilities. The passage of the CAAA has been the culmination of the growing environmental movement that began in the early 1970s. The CAAA imposes stringent requirements on the emission of SO_2 and NO_x, and other air toxics by fossil-fired plants.

To meet the requirements of the CAAA, electric utilities have several options. The utilities can either retrofit or repower existing plants to limit their pollutant emissions. The utilities can also switch from high-sulfur to low-sulfur coal to specifically reduce sulfur emissions. Finally, a utility can undercomply with the CAAA requirements on SO_2 emissions by purchasing offsetting emission credits or allowances from other utilities that overcomply. The CAAA also awards bonus allowances to utilities for engaging in conservation and generating power from renewable sources under state commission approved least-cost plans or through integrated resource planning.

In addition to switching fuels (including cofiring with natural gas) and engaging in energy conservation, other options allow a utility to choose between CGTs (either with conventional pollution control or conventional nonpolluting generation) and IGTs.

Notes: "Other" includes refuse, solar, and waste heat. Total may not equal the sum of components because of independent rounding.

Fig. 2-2. Percent of generating capability additions by energy source, 1992-2001 (Source: Energy Information Administration, *Inventory of Power Plants in the United States 1991*, 241).

Conventional pollution control options include retrofitting coal-based plants with conventional scrubbers (also called flue gas desulfurizers or FGDs) on existing plants, and building a larger proportion of new capacity using conventional renewable technologies. The competing IGT options are CCTs that include advanced precombustion cleaning of coal, repowering the boilers with clean combustion processes, and installing advanced FGDs, in-duct processes and various NO_x control systems for existing coal-fired plants, and the use of advanced nuclear and renewable technologies meeting new capacity needs. Among these, CCTs are in more advanced stages of development and closer to commercialization than most of the other options.[9]

Since most of the new capacity needs before 2000 can be met most economically by gas-fired plants, the choice of direct pollution control options during this time period is limited to the use of conventional FGDs and retrofit CCTs to meet compliance requirements on existing plants. Both of these options will have to compete with fuel switching, energy conservation, and conventional renewable technologies. For capacity needs beyond the next decade, the entire array of options mentioned so far, including various IGTs, are available to a utility or to a nonutility generator (NUG) supplying capacity to a utility.

Generating Technology Choices and National and Local Interests

The impact of technology choices of power producers goes far beyond meeting their power needs and environmental compliance requirements. They also may have profound impacts on local economies, the national economy, national security, and the environmental quality of the country as a whole.

[9] Some wind technologies are in an advanced stage of development, although their economies are still in doubt.

Generating Technology Choices and Local Interests

The local economy is affected by technology choices of power producers in several ways. If the power is produced at the least cost to the utility, it means lower rates to all ratepayers which include residential customers, small businesses, and large industries. It means lower resource costs to all sectors of the local economy producing goods and services and lower prices to consumers of these products. The cost savings can then be directed to other more productive uses which will, in turn, have positive employment and economic effects. Thus, an optimal mix of generating technologies has a general welfare-enhancing effect on the local economy.

The choice of generation mix also affects the choice of fuels and other inputs to the electricity production process. Those technologies that make greater use of local resources will have a generally beneficial impact on local employment, consumer spending, savings, and tax revenues. For example, those states that currently supply large quantities of coal to power plants, local or otherwise, are likely to benefit from the continuation of industries that are related to the mining, processing, and transportation of coal.

The local environmental quality is also affected by the technology choices of electric power producers. The national environmental standards are intended to improve the environmental quality on a national basis. Some technologies, such as solar arrays or wind farms, may have significant local environmental impacts but no adverse effect elsewhere. A state may choose to tailor the environmental standards that reflects it own preferences within the framework of national standards. The choice of generating technologies can be made to reflect such preferences through the local legislative and administrative processes, as well as regulatory policies articulated and carried out by state commissions.

The local interests impacted by generating technology choices are not independent of each other and may sometimes be in conflict. Efficient generation, on the basis of pure cost, may sometimes be in conflict with local employment objectives. Least-cost environmental compliance may not always comport with the environmental quality preferences of the local regulators. Utilities, the state commissions, and other decisionmakers may be sensitive to the impact of technology choices on the achievement of various local objectives that may be conflicting. They may seek balanced approaches that effectively trade off these objectives.

One rationale for actively considering IGTs in a power producers' generation mix is that, regardless of their differences, they are all designed to improve on the strengths and overcome the weaknesses of conventional alternatives. This can mitigate some of the conflicts between local interests affected by the choice of generating technologies and thus make the tradeoffs easier.

As an example of improved tradeoffs between local interests offered by the adoption of IGTs is the case of states with high-sulfur coal. States with high-sulfur coal can benefit from using CCTs because they can potentially achieve superior reductions of pollutants from a coal-fired plant at costs lower or comparable to other pollution reducing options such as conventional scrubbers (which may be a costlier and relatively less flexible option) and use of low-sulfur coal (which may be a low-cost and flexible option but may adversely affect local coal mining jobs). In this case, the tradeoff between environmental and local employment objectives may be made easier by the adoption of a CCT. A second benefit might be the wider use of the CCT, thus enabling continued use of the local coal.

Generating Technology Choices and National Interests

The choice of generation technologies also affects national interests. An efficient generation mix has a welfare-enhancing effect on the national economy in the same way it does on the local economy. It means lower energy prices for all sectors of the economy and a lower resource cost to society. It means lower costs for all goods and services that require electricity for production, and lower prices to consumers. The resources saved by generating electricity with a more efficient mix of technologies, fuels, and other inputs can be directed to other, more productive uses.

The choice of generation technologies affects the national economy in other ways. As in the case of the local economy, the technology choices of power producers have significant impacts on those sectors of the economy that are involved in the extraction, processing, and transportation of fuels and production of other inputs for the electricity production process. Technologies that make fuller use of economically recoverable and abundant domestic resources are likely to help the creation and the maintenance of employment opportunities in many sectors of the economy.

Perhaps the benefit most often mentioned that results from more efficient production of energy with fuller use of domestic resources is energy independence. The oil embargo in 1973 made national policymakers recognize the pitfalls of dependency on foreign oil, most of which comes from a politically volatile region of the world. The same recognition has made national energy independence synonymous with national energy security. Two basic alternatives are available to achieve greater energy independence. The first is greater reliance on domestic resources that are abundant, such as coal (or, increasingly, natural gas) for energy needs or increased use of renewable resources. The second is improving energy consumption efficiency through conservation, load management, and other demand-side management (DSM) options. Because of the resource constraints and general economics of pursuing each of these alternatives, neither one to the exclusion of the other may realize the objective of national energy security. While improvements in deploying DSM options need to continue, there is also an equally strong need to develop, deploy, and commercialize technologies that can potentially improve the utilization of domestic resources. The emerging IGTs offer opportunities to better utilize domestic resources for the production of electricity.

As in the case of local interests, there may be potential conflicts among national interests. For example, promotion of environmental quality may involve reduced use of depletable resources and use of high cost generation and pollution control options. Further, some environmentally benign technologies (such as solar generation) tend to have high capital-to-labor ratios. All of these factors, reduced use of resources, labor, and use of high cost options, may have an adverse effect on employment. Recognition of this point does not necessarily argue for favoring labor-intensive or lower cost technologies over capital-intensive or higher cost ones in all cases. Such potential conflicts need to be addressed in assessing the impact of generation technology choices. Development and adoption of IGTs may contribute toward mitigating such conflicts as labor-intensive technologies become environmentally more benign and capital-intensive technologies reduce their capital requirements.

Generating Technology Choices and Conflicts Between National and Local Interests

Besides conflicts that may potentially exist among local interests and among national interests, conflicts also may potentially exist between local and national interests that are affected by technology choices of power producers. This is best exemplified by the conflict between the need for developing a working emissions allowance market to achieve national pollution control goals with an efficient allocation of resources, and the need for some states to preserve local jobs, or for other states to try to dictate where allowances will be used in order to (such states believe) reduce environmental impacts in these states. To the extent states trade off least-cost compliance with preservation of local jobs, this can distort allowance prices and adversely impact the development of a national allowance market. A least-cost compliance plan that does not adversely affect local jobs, however, can best meet both local and national objectives. IGTs have the potential for achieving least-cost compliance of nationally mandated environmental requirements while continuing to make effective use of local resources and labor.

Generating Technology Choices and Other Unrecognized Interests

Finally, many of the impacts of generating technology choices may be unmeasurable or even intangible. For example, technologies that displace oil with electricity (such as heat pumps and electric motor vehicles) may expand both the use of coal and gas (abundant domestic resources), and contribute toward greater energy efficiency and energy security, while at the same time reducing net emissions of various pollutants.[10] Use of CCTs can achieve even further gains in energy efficiency and pollution reduction. Also, development and commercialization of certain CCTs can improve boiler designs with spinoff beneficial effects on industries that use boilers. While renewable technologies tend to be capital-intensive and in some cases may not promote the growth of jobs, relative to other electricity options, the development and deployment effort dedicated to these technologies may spin off other technologies and materials that have favorable impacts on other industries. Advances in photovoltaic science, for example, may benefit other users of crystalline materials, such as the semiconductor industry.[11] Finally, the development of IGTs may improve their marketability and export potential in other countries. Such secondary effects of technology choices are often unrecognized in policies pursued to promote national and local objectives.

Generating Technology Choices and the Current Regulatory Structure

In spite of many potential gains to be achieved, the adoption of IGTs may be impeded by a number of factors. The adoption of innovation almost always involves risk-taking. Figure 2-3 shows the risks of adopting an innovative technology in an unregulated market. The relationship between various risks are also shown in Figure

2-3. Information barriers and the resulting learning costs are a primary source of risk in any innovative technology. Information barriers lead to performance risks in both

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[10] See State of California Air Resources Board, Staff Report, *Initial Statement of Reasons for Proposed Rulemaking: Public Hearings to Consider Regulations Regarding the California Exhaust Standards and Test Procedures for 1994 and Subsequent Model Year Utility Lawn and Garden Equipment Engines* (Sacramento, CA: State of California Air Resources Board, October 1990).

[11] Solar Energy Research Institute, "The Potential of Renewable Energy," an Interlaboratory White Paper (Golden, CO: Solar Energy Research Institute, March 1990).

Fig. 2-3. Risks and barriers to adoption of an innovative technology in an unregulated market.

construction and operation. Information barriers also lead competitors to wait until an innovation is successful and then appropriate it. While the competitor gains from the innovation, the first adopter, such as a local utility or NUG, often pays the learning costs. This "free rider" may inhibit innovation. Further, competition and imitation as well as other exogenous factors contribute to demand risks of an innovative product that in turn lead to a risk of underrecovery of an innovator's investments. The underrecovery risk combined with construction and operating risks may make potential financiers reluctant to fund a risky project, even if it has good economic and environmental potential. Together, all risks contribute as barriers to innovation. Many innovations have a public-good character: society benefits more from an innovation than the private innovator. Public intervention in the form of patent protection, public funding for research and development, and tax incentives are often used to weaken the barriers to innovation. Some barriers and risk still remain and cost-reducing innovations are adopted in unregulated markets because the innovator expects to make supernormal profits in exchange for taking risks.

There are two sources of short-term supernormal profits in a free market. A cost-reducing innovation allows a firm to appropriate the cost savings on a per-unit basis from its existing market. The innovation, with a slight reduction of price below the current market level, may also expand the sales of the firm and add to its revenue stream. The unregulated market also severely penalizes innovators that fail. Risk-averse firms tend to take fewer risks because to them the potential rewards are more likely to fall short of the level needed to compensate for these risks. In a free market, therefore, innovators are generally risk-takers who expect to benefit from the prevailing risk-reward structure.[12]

The risks of adopting an innovation by a regulated firm are generally similar to those facing an unregulated firm (Figure 2-4). Several important differences exist, however. Since a regulated firm, such as an investor-owned utility (IOU), is a monopoly, it does face the risk of imitation by a competitor. The firm may be unwilling, however,

[12] More discussion of innovation in unregulated markets appears in Appendix B.

Fig. 2-4. Risks and barriers to adoption of an innovative generation technology by a regulated electric utility.

to bear the learning costs of innovation because it expects to gain little from a successful innovation. Further, a regulated utility faces the regulatory risks of prudence and "used and useful" disallowances, which may act as strong barriers to adopting an innovation.

As another barrier, the opportunity for higher profits through innovation is not present for a regulated firm. Cost reductions, achieved as a result of successful innovation, may be passed on to the ratepayers with no or little resulting gain to the innovating firm. The corresponding decline in rates may attract new customers, but the regulatory commissions, not the firm, have the ultimate discretion in setting rates for different classes of customers. If the cost savings are passed on mostly to the price-inelastic customers, for example, it is unlikely that there will be any significant increases in revenue streams. While utility commissions may allow a utility to offer promotional rates to new businesses to locate in their service territory, it is not usually tied to cost savings achieved through innovation and good management. The only exception to the argument may be the presence of regulatory lag, which allows a utility to retain its cost savings until its next rate hearing. But it is highly questionable whether this presents a sufficient incentive for cost-reducing innovations, especially for those with a long payback period. Traditional cost-plus regulation generally limits the returns a firm can earn regardless of whether it innovates or not. This generally weakens the incentive to innovate.

In sum, the risks and rewards in unregulated and regulated markets are dissimilar. It may be important now to examine which market setting offers a risk/reward structure more conducive to innovation. Table 2-1 compares the risk/reward structure in unregulated and regulated market settings. As the table indicates, regulation offers only moderate rewards for successful risk-taking (caused by either good performance or good luck) and penalizes unsuccessful risk-taking. An unregulated market, on the other hand, offers rewards and imposes penalties that are dependent on the degree of success or failure arising from risk-taking. Moderate success brings moderate rewards; stellar success leads to windfalls; likewise for failure. In fact, failure in an unregulated market may lead to a more severe penalty than the same failure in a regulated market. In a regulated setting, the reward is limited (by the upper limit on the rate-of-return (ROR))

TABLE 2-1

COMPARISON OF INCENTIVE STRUCTURES
IN MARKET AND REGULATORY SETTINGS

	Unregulated Market		Regulation	
	Outcome	Reason	Outcome	Reason
Good Performance	Moderate/high reward (unbounded)	No profit constraint	Moderate reward (bounded)	ROR constraint
Good Luck	Moderate/high reward (unbounded)	No profit constraint	Moderate reward (bounded)	ROR constraint
Bad Performance	Moderate/high penalty (unbounded)	Market test	Moderate/high penalty (bounded)	Prudence test; rate relief
Bad Luck	Moderate/high penalty (unbounded)	Market test	Moderate/high penalty (bounded)	"Used and useful" test; rate relief

and is not particularly sensitive to the degree of success. The penalty is also limited but is generally more sensitive to the degree of failure. It is reasonable to characterize the risk/reward structure in an unregulated market as symmetric and unbounded, and to characterize the risk/reward structure in a regulated setting as asymmetric and bounded. Thus, it is also reasonable to conclude that a potential innovator would prefer an unregulated market over a regulated one to deploy a product.[13] This is true because it is the very possibility of augmented earnings that induces the risk-taking firm to innovate.

It follows that an unregulated market may generally have better incentives for a socially efficient rate of innovation. Although an individual unregulated market may foster either too little or too much of a certain type of innovation at any given time, it is likely to achieve the optimal rate of innovation over the long term. Under regulation, given its weaker incentives for innovation, the rate of innovation is more likely to be too low rather than too high. Because the unregulated market presents a more symmetric distribution of innovative outcomes, it may be considered superior to a regulated market in achieving a socially efficient rate of innovation.

The foregoing discussion points to the need for improving incentives for innovation of regulated firms. Also, although NUGs are not as tightly regulated as IOUs and therefore face a more conducive environment for innovation, factors such as small size and financing arrangements accessible to NUGs may act as barriers to IGT adoption. The incentive structures facing IOUs and NUGs and their effects on IGT adoption are examined further in subsequent chapters.

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[13] This may not have always been true. In the 1960s, prior to the era of large prudence and "used and useful" disallowances, and when regulated utilities were able to earn high rates of return, innovation was generally more widespread.

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CHAPTER 3

THE CAPITAL MARKETS' TREATMENT OF RISKY INVESTMENTS BY ELECTRIC POWER PRODUCERS

Introduction

In studying the presence of economic disincentives and developing incentive policies to promote innovative generation technologies (IGTs), it is necessary to examine the generic characteristics of the investment decision both as it relates to the modern capital markets and to the internal characteristics of individual firms. The examination begins by setting up a theoretical framework for investment decisionmaking. Next, the framework is used to examine a number of illustrative investment scenarios and to discuss their practical implications. The examination concludes with a discussion of characteristics that effective incentives must possess to promote the use of new technologies.

The Investment Decision

Given a set of investment alternatives, the economic decisionmaker will select a portfolio of investments that *maximizes the expected return for a given level of risk or minimizes the risk for a given level of return*. That decision rule forms the economic basis for investment decisions both in theory and in practice. The decision rule also forms a basis for developing incentives for the adoption of new technology by either investor-owned utilities (IOUs) or nonutility generators (NUGs), and provides a workable technique to evaluate any incentive proposal.

The investment decision rule can be applied to a set of simple investment alternatives. In Table 3-1, two investment alternatives, A and B, are depicted. Each alternative has only three possible outcomes and each outcome is equally likely. Thus, if event 1 occurs, investment A will produce a 60 percent loss and investment B will

TABLE 3-1

TWO HYPOTHETICAL INVESTMENT ALTERNATIVES

Event	Investment Return A	Investment Return B
1	-60%	12%
2	10%	10%
3	80%	8%
Expected Return	10%	10%

produce a 12 percent gain. Correspondingly, if event 2 occurs, both will produce a 10 percent return and if event 3 occurs, A will produce an 80 percent return and B will produce an 8 percent return. Since each event is equally likely, the expected or average return from each investment is 10 percent.

Given these two investment alternatives it is easy to observe that investment A is more risky than investment B. Since the expected returns are the same, the decision rule dictates that investment B will clearly be preferred over investment A. By choosing B over A, risk is minimized for a given level of return, 10 percent. It should be also noted that all investors will choose investment B regardless of an individual investor's risk attitude since choosing A involves accepting greater risk without the reward of a higher expected return. There may exist what economists refer to as "risk lovers" who are willing to accept more risk without added return, but typical investors in an IOU or a NUG do not fall into that category. Thus, if the universe of investment alternatives consists of A and B, it is reasonable to assume that investment B will always be preferred.

The outcome can be changed dramatically by introducing a third alternative, investment C, as depicted in Table 3-2 along with the original investments, A and B. In

TABLE 3-2

THREE HYPOTHETICAL INVESTMENT ALTERNATIVES

Event	Investment Returns A	B	C
1	-60%	12%	80%
2	10%	10%	10%
3	80%	8%	-60%
Expected Return	10%	10%	10%

the case of investment C, if event 1 occurs, the investor receives an 80 percent return and if events 2 and 3 occur the investor receives returns of 10 percent and -60 percent, respectively. As before, since each event is equally likely, the expected return from investment C is 10 percent.

As noted, the introduction of investment C changes the investment choice dramatically. The explanation is as follows. Investment C has the same expected return as A and B, and clearly the same risk as investment A. Hence, it may appear that the introduction of investment C changes nothing. The investor will continue to select investment B unambiguously. While that may be true, the more sophisticated investor will recognize immediately a fourth investment alternative that is risk free but retains a return of 10 percent. That investor will form an investment portfolio with one-half the portfolio invested in A and one-half invested in C. With such a portfolio, the occurrence of event 1 will produce a portfolio return of 10 percent (the average of -60 percent and 80 percent) and the occurrence of events 2 and 3 will also produce a portfolio return of

10 percent. Irrespective of which event occurs, the portfolio, which is risk free, will produce a return of 10 percent, superior to B which also has an expected return of 10 percent but carries a slight risk.

Thus, the introduction of investment C changes the investment choice in a very significant manner. Without investment C, the investor will select investment B which is far less risky than investment A, but with the introduction of C, investment B will be dropped in favor of the portfolio of A and C. The change appears counterintuitive since the decision rule has produced a situation where the investor selects the two riskier alternatives over the third even though all alternatives have an expected return of 10 percent. Nevertheless, as before, risk has been minimized; but it has been accomplished with two very risky investments that also happen to interact in such a way that their combined returns are risk free and are superior to the third investment alternative which is least risky on its own.

The Investment Decision and the Capital Markets

An important insight has been made in the above example, but does it have any relation to the real world of investment decisions? In fact, the point is critical to the real world. Namely, that the capital markets will select investment alternatives not as a function of the riskiness of the individual investment, but instead on the basis of how a given investment's risk interacts with the investors's portfolio or a set of investment alternatives. The investor will continue to minimize risk for a given level of return or maximize return for a given level of risk, but the risk of a particular investment will be evaluated within the context of how that risk reduces or increases the risk of the investor's portfolio or portfolio alternatives. Consequently, the stand alone risk of a single investment is not relevant. What is critical instead is the effect of the investment on the risk of the portfolio.

Most analysts would agree with the above observations but that still leaves open the problem of measurement. In the example given, A is considered more risky than B, but in the real world, the comparison is not that simple. There are thousands (perhaps millions) of possible outcomes or events and the return given a particular event will be pure guess work in most situations. Prior to addressing the problem of measuring risks and returns, it is important to generalize what has been concluded up to this point. The conclusion is that *assuming* that if it is possible to measure risk, return, and the appropriate interactions, then the investor will choose the investment that maximizes return for a given level of risk for the *whole* portfolio.

With this measurability assumption, Figure 3-1 is a graphic representation of the universe of all investment alternatives. It includes all combinations of portfolios of opportunities that exist in the capital markets at any point in time. The vertical axis measures risk and the horizontal axis measures the expected return of each investment or portfolio. Among all of the opportunities that are available to the capital markets, Figure 3-1 has a line drawn through those opportunities that conform to the decision rule that requires maximization of return for a given level of risk or minimization of risk for a given level of return. In the parlance of finance, that line is referred to as the *efficient frontier*. Only those investments or portfolios that fall on the efficient frontier will be eligible for investment. Any other portfolios will be *inefficient* and represent inappropriate choices for the investment decisionmaker. By definition, no investment opportunities or firms with risk-return parameters exist that lie to the right of the efficient frontier. If there were, the efficient frontier would shift to the right.

Before examining how the investor will choose among those investments that are efficient, Figure 3-1 can be simplified even further with the introduction of a risk-free asset. A risk-free asset is, by definition, one for which the expected return and the actual return is always the same. Such an asset exists in the modern capital markets, namely the short-term or 90-day U.S. Treasury Bill. Assuming that an investment in U.S. T-Bills will be held to maturity, the payoff is unambiguously risk free.

The existence of that risk-free asset has profound implications for the simplification of the investment decision. Figure 3-2 depicts the same investment alternative universe as in Figure 3-1 but adds a risk-free asset. That risk-free asset can be combined with any other risky asset or portfolio. Since the risk of the risk-free asset is zero, by definition, all possible combinations of the risk-free asset and any other risky asset or portfolio will fall on a straight line connecting the risk-return points of the other risky asset with the point where the risk-free asset is located.

Figure 3-1. Graphic depiction of the universe of investment alternatives.

Figure 3-2. Graphic depiction of the universe of investment alternatives, including a risk-free asset.

Thus, if one combines asset P in Figure 3-2 with the risk-free asset, all possible portfolios will fall on the straight line connecting the location of the risk-free asset and P. No investor, however, would combine the risk-free asset with asset P or any other asset on the efficient frontier except asset M. Combining asset M and the risk-free asset produces a new efficient frontier, which is the straight line connecting the location of the risk-free asset with the risk-return point of asset M. That efficient frontier is optimum since it is consistent with the decision rule of maximizing return for a given level of risk or minimizing risk for a given level of return.

To complete the analysis, the nature of asset M must be determined. It should be noted that the risk-return combinations depicted in Figure 3-2 are the *universe* of investment opportunities. Hence, the efficient frontier formed with the risk-free asset and asset M is available to all investors. Put another way, each investor will select a portfolio on the efficient frontier and that portfolio will be some combination of the risk-free asset and asset M. Given that the investment choices involve the universe of opportunities, and all investors seek an investment strategy that places them on the efficient frontier, asset M must and can only be the market portfolio of all risky investment opportunities. If a particular investment is not contained within asset M, then no investor will hold that asset and its value will be zero.

This brings us to a rather startling conclusion: every investor will follow an investment strategy that has some very simple elements. That is, each economically rational investor will hold a portfolio that consists of the market portfolio and the risk-free asset. The particular combination will depend on the individual investor's aversion to risk. If investors are risk averse in the extreme, they will hold only the risk-free asset with none of the market portfolio. As a given investor is willing to add risk, the amount of the risk-free asset will be reduced, replaced by the market portfolio until the investor holds none of the risk-free asset and is 100 percent invested in the market portfolio. If the investor is willing to add even more risk, the holdings of the risk-free asset will become negative which, expressed another way, implies that she will sell the risk-free asset instead of buying it, which in turn implies that the investor will borrow to purchase more than 100 percent of the market portfolio. When the investor borrows, the portfolio remains on the efficient frontier but higher and to the right of the market portfolio.

It should further be noted that without stipulating how risk is to be measured, it can be concluded unambiguously that the investor's risk will be a linear function of the risk of the market portfolio. This conclusion is crucial when determining how the capital markets value a particular asset or common shares of a publicly held corporation such as the typical IOU. The conclusion is that, from the capital markets' perspective, the only risk that is important is the risk of the market portfolio. The risk associated with the individual firm is unimportant and irrelevant. Therefore, given that the firm will seek to maximize its value, the risk that is important is how the returns from the firm interact with the returns of the market portfolio. As in the original example of investment alternatives, A, B, and C, it is not the riskiness of the individual asset that is important but how the returns interact with the alternative portfolios. In the more generalized model, the relevant consideration is how the returns of the individual firm interact with the market portfolio.

What has been described is the now well known capital asset pricing model (CAPM).[1] The CAPM states that the expected return to the stockholder is a function of the market risk, and the interaction of the firm returns and the market returns. In general, an asset is said to be a "high" risk stock if when market returns are "low," the stock returns are even lower and when market returns are "high," the stock returns are even higher. An asset is said to be "low" risk, if when market returns are "low," the stock's returns are not as low and vice versa. Also, it should be emphasized that these relationships are averages since from the capital market's perspective the deviations from the averages that occur at the firm level are canceled out in the market portfolio.

Further, it is important to remember that an individual investor need not own the actual market portfolio to experience the results predicted by the CAPM. As long as a portfolio contains a sufficient number of assets or common stocks such that the individual deviations cancel out, that portfolio will approximate the market portfolio. Surprisingly, the number of different common stocks required to achieve such *diversification* is quite small and is in the range of fifteen to twenty-five randomly selected securities. It is also the case that one need not buy or sell the risk-free asset to achieve a portfolio risk that is different than the market risk. To achieve a "low"

[1] A more complete description of the Capital Asset Pricing Model can be found in Zvi Bodie, Alex Kane, and Alan J. Marcus, *Investments* (Homewood, IL: Richard D. Irwin, Inc., 1989), Chapters 8 and 9.

risk portfolio, the strategy will be to purchase securities with "low" market risk. As long as that portfolio is fully diversified, it will achieve the same results as a portfolio consisting of the market portfolio and the risk-free asset. Similarly a "high" risk portfolio can be obtained in the same way without selling the risk-free asset or borrowing.

In general then, the CAPM represents our best description of how the capital markets evaluate the risk of an individual firm and correspondingly how the capital markets set a value on the assets of the firm. There remains, however, a great deal of controversy associated with the model. There are measurement problems associated with testing the model. There are problems with the application of the model, particularly with the always difficult issue of the utilization of historical relationships to evaluate the future.[2] There are also problems associated with the model when it advises the chief executive officer to focus only on market risk and not on the individual risk of the firm that is canceled out in the market portfolio. This issue is particularly important to the problem of introducing new technology, and as a consequence a more detailed discussion regarding individual firm risk will be developed in subsequent sections.

These *caveats* notwithstanding, the CAPM remains the best description of how the modern capital markets value the firm. The value of the common shares of the firm is the discounted earnings of the firm when the discount rate is the expected return as described by the CAPM or the maximum return available for all assets with equal risk.

Characteristics of Incentive Systems for New Technology

With this background we can now address the problem of formulating the characteristics of an incentive plan or methodology that a commission could adopt in

[2] Ibid., Chapter 9.

order to encourage the use of new technology or more specifically IGTs. We begin the discussion with the proposition that an IOU or NUG will manage its resources in a fashion that is consistent with the CAPM. Thus, if a given investment alternative in new technology has an expected return that is equal to or greater than the cost of capital as determined by the CAPM, and the project risk will not change the market risk of the firm, then one can expect the firm to accept the project. If the firm rejects the project, it is reasonable to conclude that either the expected return is inadequate relative to the cost of capital or the market risk is too high relative to the returns available. The bench mark is the cost of capital as developed from the CAPM for both risk and return.

From this conclusion, it follows that if a commission wishes to encourage an IOU or NUG to experiment with new technology through some sort of economic incentive, then that incentive must focus on the fact that the risk-return tradeoff for the new technology is inadequate. Otherwise, the new technology would have already been adopted. This is, of course, an obvious statement but it serves to focus the discussion and provide a bench mark for evaluating a particular proposal that may be made to encourage the use of any new technology. If the technology has not been adopted then it follows that either the return is too low or the market risk too high; that is to say there are better investment alternatives available. They are better in the sense that they provide a higher return for the given market risk or a lower market risk for the given return.

The discussion to follow, then, considers the risk-return tradeoff and is developed in four categories including: (1) the market risk of new technology, (2) the returns of new technology for the regulated IOU, (3) the returns of new technology for the NUG, and (4) the possibility that the IOU or NUG will also consider the nonmarket risk of a new technology.

Market Risk

Concentrating first on the risk portion of the decision tradeoff, it has been shown that what is important to the capital markets is not the absolute level of risk but the interaction of the firm's share price and income with the market portfolio. That market risk from the firm's point of view is unlikely to be materially affected by the introduction of new technology.

To see this one should recall that the risks associated with the introduction of a new technology are manifested in either a failure of the new process to perform as well as existing technology, or in the possibility that the capital costs are excessive such that the profitability resulting from greater efficiency is not sufficient to cover the cost of capital. If either one or both situations materialize the IOU or the NUG has realized the risks of experimenting with new technology. It should be noted, however, that these risks are in all probability unrelated to the market portfolio and hence, from the investors point of view, are *diversifiable* and not part of the risk-return tradeoff. There may be some relationship between the introduction of IGTs and the market portfolio but on the surface the establishment of such a relationship seems highly problematic. It is problematical in the sense that a performance failure or an expenditure in excess of budget are independent of the market. Put another way, the development of an incentive to reduce the market risk of a new technology in order to encourage the use of that technology will first require a demonstration that a future relationship exists between the risks of that technology and the market portfolio. Notice also that if there exists a relationship that reduces the market risk of the firm, it is likely that the firm has already adopted the investment, thereby eliminating the need for an incentive. In essence, a failure is a process failure or a internal capital expenditure failure, both of which are unrelated to the market portfolio. Thus, any incentive aimed at reducing market risk is unlikely to be successful.[3]

Returns for the IOU

In the case of the returns from new technology for the IOU, however, we have an entirely different matter having a great deal to do with the nature of rate regulation. Consider, for the moment an investment alternative in new technology where in a completely unregulated environment the possible outcomes are as depicted in Table 3-3. The expected return is 15

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[3] Market risk, to remind the reader, refers to riskiness relative to a basket of other investments.

percent given that each of the eight events are equally likely
and the range of possible returns is from a low of a negative 20 percent to a high of 50 percent. If the market risk is unaffected by this new investment and the cost of capital as implied by the CAPM is equal to or less than 15 percent, then the firm in an unregulated environment will make the investment.[4]

In a regulated environment, however, the behavior of the firm will not be quite so predictable. To see this, consider an IOU that is operating under a commission order that sets rates based upon a cost of capital of 12.5 percent. Assuming that market risk is unaffected, the economics of the project depicted in Table 3-3 suggest that it should be accepted but as any utility executive will note, it may not for good profit maximizing reasons. What would happen, for example, if the technology were highly successful and event 8 occurred, producing a 50 percent rate of return on the project, and as a consequence, the IOU's earnings increased such that actual total corporate earnings were no longer 12.5 percent but increased, say, to 15 percent because of the 50 percent return on the new technology? Perhaps nothing, but it is likely that a commission order would be forthcoming which would have the result of reducing prices sufficient to return the corporate rate of return to 12.5 percent. Put another way, it is not unreasonable to postulate that if event 8 were to occur, the IOU would be required to pass the benefit to the ratepayer rather than to the stockholder as would be the case in an unregulated environment.

Some might argue that the ratepayer should benefit from the new technology as they would in the long run in a truly competitive environment. Indeed, both the stockholder and the ratepayer should benefit, but by forcing the benefits to be passed on

[4] It should be noted that the firm may impose a higher minimum investment return then the cost of capital for a variety of reasons including problems with the measurement of the cost of capital, capital rationing, a preference to avoid going to the capital markets to name a few. A minimum will nevertheless exist which is the only requirement of the following analysis.

TABLE 3-3

RATE-OF-RETURN POSSIBILITIES FOR
AN INVESTMENT IN NEW TECHNOLOGY

Event	Investment Returns
1	-20%
2	-10%
3	0%
4	10%
5	20%
6	30%
7	40%
8	50%
Expected Return	15%

to the ratepayer in a relatively short period of time, the regulator runs the risk of preventing the investment in new technology. Suppose that the IOU believes that if events 6, 7, or 8 occur, then the regulator will require that a portion of the benefits be passed on to the ratepayer and that the method probably utilized will be to set rates such that the actual project return will not exceed 20 percent. Apparently, the arrangement is quite fair. The ratepayer is better off with lower rates and the stockholder has been rewarded with a 20 percent return, which is well in excess of the cost of capital. All have benefitted as would be the case in a competitive environment.

If the IOU believes, on the other hand, that the commission will in fact behave in a way such that events 6, 7, and 8 will produce a rate of return of 20 percent, then the IOU will reject the project initially and neither the stockholder nor the ratepayer will have the opportunity to benefit from the investment. What has happened is that the projected actions of the regulator will reduce the expected return of the project from 15 percent to 7.5 percent, which is the average of the returns when events 6, 7, and 8 are limited to 20 percent instead of their actual returns of 30 percent, 40 percent, and 50 percent, respectively. With a cost of capital of 12.5 percent the IOU executive should, from the stockholders' point of view, reject the project on the basis of an expected return that is below the cost of capital. In the parlance of finance, the project now has a negative net present value and should not be undertaken not because of the economics of the project but because of the perceived or real risk that high returns may not be permitted under the regulated environment.

Of course, it is possible that this "regulatory risk" works both ways in the sense that lower rates of return are also limited by the regulation process and indeed they often are. Suppose that in this example, the IOU believes that given a favorable prudence review, the commission will allow the inclusion of the capital cost of a new technology project in the rate base. Other than a time value of money issue, such an allowance will prohibit negative returns on those investment projects, and depending on how the capital allowance is made, may guarantee a minimum return of the allowed cost of capital. In other words, if, in the example, events 1 or 2 were to occur, then instead of project returns of -20 percent and -10 percent, respectively, the actual returns would be zero if only capital recovery were allowed and higher if a return is allowed on the invested capital through inclusion in the rate base. In the example, if a zero return were the minimum return allowed within the rate structure permitted by the commission, then the expected return of project would be 11.25 percent, assuming again an allowed upper bound of 20 percent. This is still lower than 12.5 percent, the cost of capital. If, however, the commission guarantees a minimum return of 12.5 percent, then the expected return once again becomes favorable with an even higher net present value than would be the case if the regulator imposed no upper or lower bounds.[5]

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[5] This is equivalent to a preapproval of prudence. The merits and demerits of a preapproval of prudence are discussed in Chapter 6.

Thus in this example, the establishment of an upper bound on the allowed project rate of return by the regulator will cause the IOU to reject the investment even though the economics of the project are perfectly acceptable. This condition can be partially or completely offset by the establishment of a lower bound on the rate of return. In the example, a lower bound of zero was not sufficient to offset the effect of the imposition of an upper bound, while the imposition of a lower bound equal to the cost of capital not only offset the upper bound but, as it will in all cases, improved the expected return of the project. Simple averaging makes this the case.

The above may not be a "real world" example but the logic of the example does indeed apply to the real world. If an IOU believes that the regulator will prohibit returns above a certain magnitude, then the expected value of any investment will be lower than would be the case in an unregulated environment. If the limits are low enough, then a perfectly acceptable investment project may be rejected not because of economics but because of arbitrarily imposed rate of return limits. Whether or not a given commission will in fact limit such returns is an empirical question and must be answered at the local level in the context of local conditions and politics. It would seem, however, that most IOU executives believe that such limits are in fact imposed. Witness for example the several proposals by many telephone companies to utilize price-cap regulation rather than cost-based regulation.[6]

What may be particularly important is the historical experience of many IOUs with cost disallowances, determined by a regulator through the use of prudence reviews and "used and useful" tests, to force all or part of the capital cost of a failed investment, or of a good investment that retroactively was found to be unnecessary, out of the rate base, with the added prohibition of depreciation of the capital costs. In the extreme, such disallowances can result in a 100 percent loss on the investment in new technology and while the occurrence of such total disallowances is rare, even more modest disallowances, or the anticipation of more modest disallowances, can drastically alter the decision to invest in new technology. This perception, when combined with

[6] For example, Ameritech's state subsidiaries either are currently subject to, or are planning to request, price caps with a lifting of rate-of-return regulation provided the price caps remain.

the belief that an upper bound on the rate of return of a successful new technology exists, understandably will severely limit the investment in risky projects by the regulated IOU.

It is also true that local conditions change with time. That is, an IOU executive may be perfectly willing to participate in a given incentive system but understands that local conditions, politics, or regulators may change resulting in an inability of the regulator to continue to enforce the incentive. If a project earns average returns, there is no problem. If, however, the IOU is earning very high returns on a given new technology project it would be naive to think that there would not be considerable pressure on all concerned to lower rates and thereby pass on the profitability to the consumer. That is particularly likely to be the case when a new technology is successful as there is no obvious short-run "cost" of immediately passing on the gains. The difficulty is that if, on an *ex ante* basis, the IOU believes that the regulator will succumb to those pressures, the IOU will not invest in the technology because it expects to earn a lower return as shown by the preceding hypothetical example. One must always bear in mind that decisions are *ex ante* while results are *ex post*. The introduction of new technology will hinge on the IOU's prediction of the future. If that prediction involves a rate-of-return limit on successful projects, good economically viable projects are likely to be rejected.

In essence, the investment in new technology that is perfectly viable from a economic risk-return point of view may be rejected by the IOU not because of excess market risk or low expected returns but instead because the regulatory process will limit the profit potential to some arbitrary upper limit. That upper limit may be partially or fully offset by a perception of a lower limit, but also in today's environment the perception of a lower limit may be insufficient to offset the upper limit. Any incentive regulation designed to encourage the introduction of new technology must first and foremost deal with the issue of investment alternatives that are economically acceptable within a competitive market but have not been undertaken because of regulatory limits on both ends of the risk-return continuum.

Returns for the NUG

Turning next to the case of the returns from a new technology for the NUG, there are no limits imposed on the returns (assuming correctly that prices are generally based on market forces). As a consequence, the acceptance or rejection of a new technology by NUGs will hinge on their estimates of the actual risk-return parameters of the investment project as dictated by the economies of the new technology. As noted earlier, if a given technology has not been adopted or experimented with by a NUG, then it is reasonable to conclude that either the market risk is "too high" or the expected return is "too low" or some combination of the two. In the parlance of finance, the new technology is not on the efficient frontier. Otherwise the NUG would embrace that technology. One should note that any situation where the risk-return parameters are not favorable to the NUG also applies to the IOU exclusive of the problem of regulatory distortions.

At this point a word of caution is necessary. The evolution of the NUG is still in the learning stages and with the latest Public Utility Holding Company Act of 1935 (PUHCA) reforms we are likely to see an even faster expansion of NUGs. In effect, we could be in a situation where the introduction of an IGT will not come about because of added regulatory incentives but from the NUGs rather than from the IOUs. Indeed, if the IGT has a set of favorable risk-return parameters, then we will see the adoption of that technology as new NUG capacity comes on line. That adoption may have not yet occurred simply because the NUGs have matured insufficiently to begin to experiment with new technology, and not because of unfavorable risk-return parameters of IGTs.[7]

If, however, the failure of the NUGs to adopt IGTs results from unfavorable risk-return parameters, then any incentive system must directly address the simple fact that the technology is not economically viable at this stage. That means, of course, that the investments in new technology must be moved to the efficient frontier either by increasing expected returns or lowering risk or both. As noted earlier, reducing risk or at least market risk does not seem to offer a viable solution since the risks of new technology are unlikely to be related to the market portfolio risk.

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[7] The asset base of a typical NUG is comparable to the size of a typical IGT project (~300 MW). Also, most NUGs are project financed. These factors, which may reflect immature development of the NUG sector, make it difficult to obtain financing for risky and high capital projects, unless there are offsetting factors (for example, higher-than-market returns for specific technologies).

To improve the economic viability of a new technology an almost infinite variety of techniques available exists. Some examples include more rapid depreciation, the manipulation of state and local tax policy, minimum customer rates, guaranteed markets, guaranteed minimum rates of return, and even direct subsidies.

From a practical point of view there are two important problems with this approach. The first and more complex problem is that by introducing an incentive to the NUG, the commission or regulatory authority has also introduced another form of regulatory risk. That risk is, of course, the possibility that the commission may remove or modify the incentive prior to the termination of the investment project. The other problem, which may be less difficult, is deciding how much incentive to apply. The incentive should be just enough to move the technology to the efficient frontier. This is equivalent to bringing the expected return of the new technology project up to the cost of capital of the NUG. That, of course is exactly what a commission tries to do with a regulated utility through a series of approximations; there is no reason to believe that the same could not be done for new technology that is adopted by the NUG without introducing a great deal of regulatory interference with the NUG.

Nonmarket Risk

Turning, then, to the possibility that the IOU or NUG will consider nonmarket or diversifiable risk when developing the decision to accept or reject the adoption of a new technology, we find a very ambiguous state of affairs.[8] It is ambiguous in the sense that consideration of such risks will not significantly affect the value of the firm from the stockholders' point of view. From the point of view of the management, the employees, suppliers, or creditors, however, the diversifiable risk may be very real and critical to their interests. For example, the recent bankruptcy of Columbia Gas was a random disturbance to the fully diversified portfolio and undoubtedly was balanced by another positive random disturbance within the portfolio as far

[8] This risk emanates entirely from the characteristics of the technology and the firm.

as the investors are concerned.[9] On the other hand, it is certain that the same bankruptcy was a major issue to the management and employees of Columbia Gas. Careers were interrupted or destroyed, income decreased, and jobs were lost. These risks were not, nor could they be efficiently diversified away.

It is important to observe that while management's function is to maximize the wealth of the stockholders, which translates to minimizing market risk for a given level of return and ignoring nonmarket or diversifiable risk, it is not realistic to believe that management will always behave in this manner. Diversifiable risk may indeed be a critical element in the decision to invest in a new technology and, hence, must be considered when developing an incentive system for encouraging such an investment.

Notice, however, that any incentive system that addresses the rate of return issue is unlikely to be independent of diversifiable risk. Recall that in the case of a perfectly viable new technology project from a risk-return point of view, the IOU may not invest because of a belief that very "high" rates of return will not be allowed by the regulator. That belief will reduce the expected return, thereby generating a rejection of the investment project. It is also the case that the IOU may believe that the regulator will also limit the losses of an investment project by allowing the IOU to include some or all of the investment in the rate base thereby increasing the expected return. By limiting large gains *and* large losses, the expected return may be high enough to return the project to economic viability.

Notice, however, that by limiting "large" gains and "large" losses for the IOU, the regulator has also eliminated much of the nonmarket or diversifiable risk of the investment in new technology. Hence, any solution to the problem of lower expected returns also needs to address the diversifiable risk problem unless the solution is a totally market solution. That is, if the solution is one where the regulator will allow the very high returns, but fails to support very low return possibilities, then diversifiable risk would still be too low. While any incentive system that places a reasonable floor on the earnings of an investment in new technology will increase the expected return of the project, it will have the same problem of reducing or eliminating nonmarket

[9] For example, stockholders of Columbia Gas most likely had stock in other firms that increased in value to balance this bankruptcy.

or diversifiable risk.

Summary

In summary, we can characterize an incentive system designed to encourage an IOU or NUG to invest in new technology including IGTs in the following manner: (1) the system, in all probability, need not account for the effect of the project on the market risk of the firm for either the IOU or the NUG, and as a consequence the focus of the incentive must be on the rates of return of the new technology projects; (2) if the new technology is not economically viable in the sense that its expected returns are less than the cost of capital, then any system must focus on improving the rate of return to either the IOU or the NUG but should be limited to bringing the expected return, but not necessarily the actual return from the new technology, up to the cost of capital; (3) if the new technology is economically viable, then any incentive system must focus on the elimination of regulatory risk either by allowing the "high" rate of return possibilities, or supporting the "low" return possibilities, or some combination of the two; (4) it is probable that diversifiable risk must be considered but any incentive system that is designed to address this nonmarket risk is probably not necessary if support for the low return possibilities is provided in some manner; and (5) since virtually any investment in new technology will be long term in nature, it is important to recognize that the usefulness of any incentive will be largely a function of the perceptions of the IOU or NUG regarding whether or not the regulator will maintain the incentive throughout a reasonable investment horizon.

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CHAPTER 4

THE ADOPTION OF INNOVATIVE GENERATING TECHNOLOGIES BY REGULATED UTILITIES: EFFECT OF CURRENT REGULATORY PRACTICES AND IMPLICATIONS OF EMERGING REGULATORY AND INDUSTRY TRENDS

Introduction

There is a widespread perception that regulation provides weaker incentives for hard work and good decisionmaking than does the "invisible hand" of competition. Indeed, the vast academic literature, from Averch and Johnson[1] to, for example, Braeutigam and Panzar[2] (among many recent contributions), has documented the distortions that may be caused by regulation. For the most part, however, this literature has not focused on the regulated firm's incentives to adopt new technology. Nevertheless, the "conventional wisdom" seems to be that regulation causes firms to be slow to take advantage of new opportunities and to avoid taking risks; since the costs and benefits of new technologies tend to be uncertain, the standard intuition would seem to be that utilities fail to fully capitalize on new technologies.

If these concerns are valid and deregulation is infeasible, there is a case for government attempts to provide stronger incentives for the adoption of new technologies. The net social benefits of innovative generation technologies (IGTs) could be quite large, according to some estimates. One recent study found that a representative midwestern utility could reduce the net present value of its revenue requirements by as much as

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[1] Harvey Averch and Leland Johnson, "Behavior of the Firm Under Regulatory Constraint," *American Economic Review* 52 (1962): 1053-69.

[2] Ronald R. Braeutigam and John Panzar, "Diversification Incentives Under `Price-Based' and `Cost-Based' Regulation," *The RAND Journal of Economics* 20 (1989): 373-91.

$1.226 billion if it switched from a conventional generation technology (CGT) such as pulverized coal with flue gas desulfurization (PC/FGD) to PFBC.[3]

There have been a few empirical analyses of the diffusion of new technology in regulated industries. Typically, diffusion occurs gradually as the adoption cost or the uncertainty about the innovation declines over time. Empirical work aims to identify firm or industry-specific factors that explain the rate of diffusion and predict which firms will adopt early or late. The literature includes studies of the adoption of nuclear power and of various coal-burning technologies. Authors have examined explanatory variables such as expected cost savings from adoption, firm size, ownership structure, membership in power pools, experience with a given technology (either by a single firm or the industry as a whole), and degree of uncertainty about operating performance measures such as capacity factor.

Sommers[4] develops a model where uncertainty about the technology is not necessarily reduced over time, and applies this model to utilities' decisions to adopt nuclear power. He focuses on the key uncertainties of construction costs, operating performance, and reliability. For utilities that have not yet adopted nuclear power, uncertainty may remain high in part because nuclear plant cost and performance are highly firm-specific. Sommers, not surprisingly, finds that the less certain a utility was about the capital costs and/or reliability of nuclear plants relative to coal plants, the less likely it was to adopt nuclear power. In addition, larger utilities and utilities belonging to power pools were more likely to adopt nuclear power.

Zimmerman[5] examines the expected and actual costs of nuclear power over time, focusing on whether learning effects are transferable across firms. He finds that experience gained from the construction of the first few nuclear plants in the United States led to lower costs and reduced

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[3] This estimate is derived from Table 5-6, found in K. A. McDermott et al., *An Examination of Incentive Mechanisms for Clean Coal Technologies, Applicable to Utility and Nonutility Power Generators* (Argonne, IL: Argonne National Laboratory, October 1991). It assumes PFBC experiences no construction cost overruns or unusually large forced outages.

[4] Paul Sommers, "The Adoption of Nuclear Power Generation," *The Bell Journal of Economics* 11, no. 1 (1980): 283-91.

[5] Martin B. Zimmerman, "Learning Effects and the Commercialization of New Technologies: the Case of Nuclear Power," *The Bell Journal of Economics* 13 (1982): 297-310.

cost uncertainty. Furthermore, some of the learning was appropriable by other firms throughout the industry. This might suggest that pilot/demonstration plants are important, and that government subsidy of early plants would be a useful response to the apparent learning externality. However, Zimmerman concludes:

> A large number of nuclear plants were ordered without the benefit of experience with commercial-scale plants.[6] Had the government built or subsidized earlier construction, there would have been only a slight effect on the future rate of commercialization. Since investment behavior would have been similar with or without subsidy, the value of the better cost information was small.[7,8]

Rose and Joskow[9] study the adoption of high pressure, conventional coal-burning plants and very high-pressure supercritical coal units over the period 1950 to 1980. A key aspect of their approach is to distinguish between a firm's *opportunities* to adopt and its innate *propensity* to adopt. Thus, they control for the fact that larger utilities build more often and can better take advantage of scale-augmenting technologies. They do not attempt to measure uncertainty about costs directly, relying instead on proxies such as the number of previous plants built. They find that large, investor-owned electric utilities tended to adopt new coal-fired generating technology earlier than did smaller firms or government-owned firms.

These empirical studies give insight into the characteristics of firms that tend to adopt new technology. They do not, unfortunately, shed much light on whether regulated firms are too cautious or too zealous in their pursuit of new technology. The only aspect of regulation included

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6 One possible explanation for this, which is discussed in more detail later, is that utilities had a relaxed attitude toward risk during the 1960 to 1973 period because of the rarity of retrospective reviews over that time period.

7 Ibid., 309.

8 The investments were encouraged, even in the absence of direct subsidies, by a perception that the low recovery risks that existed prior to the 1970s continue along with the federal government's campaign for the "atoms for peace" program.

9 Nancy L. Rose and Paul L. Joskow, "The Diffusion of New Technologies: Evidence from the Electric Utility Industry," *The RAND Journal of Economics* 21 (1990): 354-73.

in any of these studies is Rose and Joskow's distinction between investor-owned and government-owned utilities, which suggests that public utility regulation creates greater incentives for the adoption of new technologies than does government ownership.[10] Otherwise, none of the models include variables describing the form or stringency of regulation faced by the different utilities. Nor do any of these studies look for differences in adoption propensities between utilities and nonutility generators. A particularly important omission in these studies is the absence of a measure of the effect of retrospective cost disallowances by regulatory commissions; as discussed in a subsequent section, such disallowances may have significantly altered utility investment behavior in the 1980s and 1990s.

Given the paucity of empirical evidence, this chapter aims to analytically identify the key features of regulation as it is applied to electric utilities, and to assess their net effect on the regulated firm's technology adoption decisions. The remainder of the chapter is organized as follows. The next section, "Research, Development, and the Adoption of New Technologies in Unregulated Markets," mentions some of the ways in which research, development, and the adoption of new technologies may be socially suboptimal in unregulated markets. No attempt is made to provide balanced coverage of

[10] Most government-owned utilities are relatively small (~100 MW) and are not likely to build or purchase large units.

the vast literature on this topic. Instead, the intention is merely to point out that the competitive market is an imperfect welfare standard where issues of technology are concerned. Next, the section entitled, "The Effect of Regulation on the Adoption of Innovation: An Analytical Framework," identifies six important features of regulation, and discusses how they may affect a firm's decision to adopt a new technology. The section, "Historical Experience with Innovative Generation Technologies," reviews the electric utility industry's historical experience with the adoption of innovative technologies under the traditional "regulatory bargain." The traditional regulatory bargain was radically changed by the use of retrospective cost disallowances in the 1980s. Since this period is less well documented, the effects of hindsight review are assessed using a simulation analysis as reported under "Simulation Results." The analysis highlights how the incorporation of "hindsight reviews" into the regulatory bargain may discourage a utility from adopting IGTs. The next section, "Overall Effects of Regulation on the Adoption of IGTs in the 1990s," integrates the foregoing elements to describe the net effect of regulation on the adoption of innovative technologies in the 1990s.

Research, Development, and the Adoption of New Technologies in Unregulated Markets

Economists have long trumpeted the virtues of competition. While these virtues are many, complications arise when technological change is an important feature of an industry. These complications include: (1) the creation of monopolies over new technologies, (2) research and development (R&D) programs that may be excessively risky, and (3) diffusion of new technology that may be either too fast or too slow.

Schumpeter[11] argued that oligopolies may be preferable to perfect competition because the inefficiencies associated with oligopolistic market power in the short run are

[11] Joseph Schumpeter, *Capitalism, Socialism, and Democracy* (London: Unwin University Books, 1943).

outweighed by long-run efficiencies in technological advances.[12] This tradeoff between static and dynamic efficiency is at the heart of patent law. Because knowledge is cheap to transmit and hard to keep secret in the absence of patent protection, too little research and development would be undertaken. While patents induce more R&D, they do so at the cost of creating (temporary) monopolies.[13]

In addition, patents may bias firms' choices regarding the riskiness of their R&D programs. In a patent race, being second is worthless. Thus, firms competing against multiple rivals may prefer risky strategies that increase the chance of being first, even if they also increase the *expected* time to discovery.[14] Since society as a whole does not care which firm wins the race, private objectives and social objectives diverge, and firms may undertake excessively risky strategies.

Even after new technologies are discovered, their adoption by firms may occur in a socially suboptimal fashion in unregulated markets. Two types of problems may occur. An innovation with a relatively low probability of success may not be adopted by any firms in the industry, even though society would benefit if at least one adopted. On the other hand, an innovation with a relatively high probability of success may be adopted by

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[12] Later refinements in theory and empirical evidence, however, did not always agree with the Schumpeterian thesis. See F. M. Scherer, "Size of Firm, Oligopoly, and Research: A Comment," *Canadian Journal of Economics and Political Science* 31 (1965), 256-66; and Morton L. Kamien and Nancy L. Schwartz, *Market Structure and Innovation* (Cambridge, MA: Cambridge University Press, 1982). Also, innovations in the U.S. steel, auto, and computer industries can be traced to competition from either domestic or foreign competitors.

[13] There is a rapidly growing literature on the optimal length and breadth of patents. For a good introduction, see "Symposium on Patents and Technology Licensing," *The RAND Journal of Economics* 21, no. 1 (Spring 1990).

[14] See Tor Klette and David de Meza, "Is the Market Biased Against Risky R&D?" *The RAND Journal of Economics* 17 (1986): 133-39.

all firms, even though expected social surplus would be increased if some did not adopt.[15]

These examples highlight the variety of problems markets may have in developing new technology. To argue that distortions in technological change would be eliminated if only the adoption of new technologies were "left to the market" may not be entirely correct. Furthermore, it may well be impossible to determine whether an industry composed of a few large firms or one composed of many small ones is more conducive to technological progress. In fact, according to Edwin Mansfield, a leading student of innovation:

> [T]here seem to be considerable advantages in a diversity of firm sizes. . .Moreover, the optimal average size is likely to be directly related to the costliness and the scope of the inventions that arise. However. . .there is little evidence that the inventions of industrial giants are needed in all or even most industries to promote rapid technological change and rapid utilization of new techniques.

The Effect of Regulation on the Adoption of Innovation: An Analytical Framework

Regulation, while often confusingly complex, generally exhibits a few key features that have important effects on the firm's behavior. This section identifies and discusses six such features: (1) monopoly status, (2) regulatory lag, (3) bounds on earnings, (4) bounds on risk, (5) fuel adjustment clauses (FACs), and (6) retrospective disallowance. The independent effects of each feature are discussed first, and their aggregate effect is summarized at the end of the section.

[15] See Richard Jensen, "Innovation Adoption and Welfare under Uncertainty," *The Journal of Industrial Economics* 40 (1992): 173-80.

Monopoly Status

Electric utilities are regulated because they are natural monopolies in at least some of their services, for example, local distribution (once a utility is determined to be a natural monopoly and regulated, of course, regulatory barriers to entry reinforce the original determination). Monopoly status has conflicting effects on the firm's incentives to innovate.

On the one hand, the monopoly is not worried about competitors imitating its innovation. Just as monopolies created by patent protection are thought to enhance incentives to innovate, natural (unregulated) monopoly status should support innovation. On the other hand, Arrow[16] has argued that an unregulated monopolist will have suboptimal incentives to engage in cost-reducing innovation. Such a firm will restrict output below the competitive level, so reductions in marginal cost will be spread over fewer units sold. Cost-reducing innovation is thus less attractive to the monopolist than to a competitive firm, which can obtain the entire market (at least temporarily) if it can reduce costs and undercut the prices charged by its rivals. This phenomenon is referred to as the Arrow effect.[17] For a regulated monopolist who does not have opportunities to make supernormal profits, innovation should be even less attractive.

The Arrow effect can be mitigated if the monopolist faces a threat from potential competitors, and engages in preemptive technology adoption to deter their entry. Thus, reducing entry restrictions could at least partly overcome the Arrow effect. Even if strong entry restrictions are retained, the monopolist's incentives to innovate can be enhanced by regulation that uses marginal-cost pricing to increase output (presumably as part of a two-part tariff for firms with declining average costs). If price were to perfectly track changes in marginal cost, however, the firm would have no incentive to innovate. Thus, there must be an interval between the time

[16] Kenneth J. Arrow, "Economic Welfare and the Allocation of Resources for Invention," in *The Rate and Direction of Inventive Activity*, National Bureau of Economic Research (Princeton, NJ: Princeton University Press, 1962).

[17] Regulatory bounds on the firm's earnings may exacerbate this effect, as discussed in a subsequent section. The unfavorable response of capital markets to bounds on earnings was discussed in Chapter 3.

cost-reducing innovations occur and the time prices are reduced to pass the gains along to consumers.

Regulatory Lag

Because regulatory bureaucracies (as all other bureaucracies) react slowly to changing circumstances, some interval between cost reduction and price reduction is assured. Even after a formal rate review is initiated, a period of some months is required for regulators to hear the views of parties interested in the proceedings and to sift through the voluminous evidence that is generated. The length of this period is often referred to as regulatory "processing lag." Because a review is generally not initiated immediately upon a successful cost reduction,[18] processing lag sets a lower bound on the interval between cost reduction and price reduction. Determining the optimal processing lag (and defining the events that should properly trigger a rate review) is a difficult problem similar in some respects to the problem of determining the optimal patent life.[19] Processing lag, however, is typically much shorter in duration than the seventeen-year period of patent protection.

[18] The events that trigger a rate review are discussed below.

[19] There appears to be no rigorous academic treatment of optimal regulatory lag. A number of issues must be considered, however. When the firm is the main initiator of rate reviews, it may be able to manipulate the regulatory process to its advantage. Yet if reviews occur at fixed intervals, the firm has incentives to pad costs just before a review so as to receive higher rates in the following period. Another alternative is for reviews to be triggered randomly. In this case, however, the regulator may face a difficult tradeoff: reviews may have to be more likely after periods of high earnings than low earnings in order to deter the firm from padding costs; on the other hand, if costs are rising over time and reviews are infrequent when losses are incurred, the firm's viability may be placed in jeopardy. These issues are discussed in Thomas P. Lyon, "Evaluating the Performance of Non-Bayesian Regulatory Mechanisms," mimeo, Indiana University (July 1992), though for purposes other than solving for the optimal regulatory lag.

Because of its relatively short duration, processing lag creates incentives for inexpensive innovations with short payback periods, but generally gives little incentive for major innovations with high up-front costs, which will only pay for themselves over a long period of time. Furthermore, the effects of lag on innovation depend on the time trend in the utility's input costs. In an era of declining costs or growing demand, rate reviews may be infrequent, especially if consumers are more concerned about increases in nominal prices than increases in the firm's earnings. The resulting extended periods between reviews increase the firm's incentive to innovate. During the 1950s and 1960s, the cost of generation declined and demand for electricity grew steadily. Rate reviews were relatively infrequent, and, as discussed below, firms adopted a number of innovative technologies. A similar pattern may be at work in the telecommunications industry during the 1980s and 1990s.[20] On the other hand, in an era of increasing costs or falling demand, frequent rate reviews may be required to protect the firm's solvency. The resulting brief periods between reviews give the firm little incentive to innovate. For example, Joskow,[21] has discussed how inflation, oil price shocks, and stricter environmental standards led to significant increases in electricity generating costs in the late 1960s and early 1970s.[22] These cost increases (to a large extent beyond the control of utilities) could not be reflected in rates fast enough to keep profits from falling. Eventually FACs (and, to a lesser extent, future test years) were implemented in an attempt to alleviate at least part of the problem.[23]

For the most part, lag emerges as an expression of bureaucratic inertia rather than as a result of conscious choice by regulators. This is changing somewhat, however, as regulators

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[20] It is important to note, however, that new telecommunications technology often directly enhances service, while IGTs are focused on reducing costs and improving an indirect service or good (for example, lower environmental emissions).

[21] Paul Joskow, "Inflation and Environmental Concern: Structural Change in the Process of Public Utility Regulation," *Journal of Law and Economics* 17 (1974): 291-327.

[22] As an outcome of using generation costs, the long-term decline in nominal electricity prices stopped about 1970, with prices starting to rise about the time of the 1973-1974 oil embargo (Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry, 1981* (Washington, D.C.: Edison Electric Institute, 1982).

[23] Fuel adjustment clauses create their own incentive problems, as discussed below.

experiment with various forms of "incentive regulation."[24] For example, the California Public Utility Commission has imposed fixed lag periods of three years for some utility rates.

Bounds on Earnings

Regulators of monopolies attempt to avoid monopolistic "price gouging" while allowing the firm to earn a return sufficient to keep it solvent and attract capital. Thus an important task for the regulator is determining the rate of return on capital that will attract new investment. This "cost of capital" must, of course, reflect the level of risk the investment poses to potential holders of the utility's debt or equity. Once the "allowed rate of return" has been established, it is intended to set an upper bound on the firm's earnings. It does not provide a *guarantee* of the firm's actual rate of return nor is it necessarily equal to the firm's *expected* or actual return.[25]

The above stylized facts form the basis for the best known model of economic regulation. Averch and Johnson,[26] in their seminal 1962 paper, viewed the firm as selecting a mix of capital and labor inputs (to an exogenously specified production process), and setting a price, subject to the constraint that the firm's return on capital must be no greater than the allowed rate of return. Assuming that regulators set the allowed rate of return greater than the firm's actual cost of capital,[27] Averch and Johnson show that the firm will overcapitalize. By this they mean that the firm uses a capital/labor ratio that is greater than the cost-minimizing ratio, given the firm's output level (the phenomenon often referred to as the "A-J effect"). Expanding its rate base (capital

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[24] See, for example, Paul Joskow and Richard Schmalensee, "Incentive Regulation for Electric Utilities," *Yale Journal on Regulation* (1986): 1-50; or Lorenzo Brown, Michael A. Einhorn, and Ingo Vogelsang, "Toward Improved and Practical Incentive Regulation," *Journal of Regulatory Economics* 3 (1991): 323-38.

[25] As discussed below, before 1970 utilities expected to earn higher than the allowed rate of return because of regulatory lag.

[26] Averch and Johnson, "Behavior of the Firm Under Regulatory Constraint."

[27] A number of observers have argued that the firm's expected rate of return in the early 1990s actually may have been less than its cost of capital, given the ubiquity of "prudence" and "used-and-useful" disallowances in recent rate hearings.

inputs) is the only way the firm can earn increasing profits.

When a bound on earnings limits upside potential but not downside risk, it tends to discourage firms from taking some otherwise justified risks.[28] This accurately describes the condition faced by regulated electric utilities for the past several years when state commissions started to exercise more vigorously their retrospective-review authority. In contrast, especially before 1970, bounds on earnings were relaxed, with regulators allowing utilities to retain high profits from innovation and other cost-reducing activities. Further, utilities probably perceived potential losses from innovation to be minimal partially because of few or no signals from regulators indicating that they would place a utility in financial jeopardy. To the extent this was true, utilities had the perception prior to roughly 1970 that the profits they were able to earn, from the regulators' perspective, could not be too high but they could be too low. In this environment utilities had much incentive to adopt new technologies and innovate in other ways that lowered their cost of service. Over the last several years, regulated firms have been less inclined to select projects involving innovative technologies whose cost and/or performance is uncertain. Bounds on earnings provide one explanation for the intuition that regulation inhibits the adoption of IGTs and for the decrease in generation innovations by utilities over the past several years.

The A-J depiction of regulation has experienced considerable criticism, notably by Joskow.[29] He points out that in practice regulators are more concerned with preventing increases in the firm's nominal prices than they are with constraining the firm's rate of return. Furthermore, when a rate review is held, regulators attempt to set price based on an allowed rate of return that is equal to, not greater than, the firm's cost of capital. Historically, until the last twenty years, regulators have tended to be relatively passive agents, convening rate reviews and adjusting prices only when pressured to do so by the firm (if earnings are too low) or by consumers or consumer

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[28] H. Stuart Burness, W. David Montgomery, and James Quirk, "Capital Contracting and the Regulated Firm," *American Economic Review* 70 (June 1980): 342-54, show formally that if a regulated firm faces a choice between two projects whose expected construction costs are equal, bounds on earnings cause it to prefer the project without uncertainty or, in other words, the conventional technology.

[29] Joskow, "Inflation and Environmental Concern."

representatives (if earnings are exorbitant).[30] The former is more likely when costs are rising or demand is falling, as has been the case for the past roughly twenty years; but the latter may be expected to occur eventually if costs are declining or demand is growing, as was the case prior to about 1970.[31]

Braeutigam and Quirk[32] show that over the period 1948 to 1977 utility petitions for rate increases were by far the most common reason for a rate review: of 363 rate cases, 350 were utility petitions for rate increase, 15 were utility petitions for rate decrease, and 13 were regulator-initiated petitions for rate decreases.[33] Thus, until 1977, consumer representatives (or the public utility commission) placed only a loose ceiling on a regulated firm's earnings. In accordance with the Joskow model, this ceiling

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[30] More recently, regulators have been playing a more activistic role, engaging in closer scrutiny and oversight of utility planning and management through commission-initiated prudence reviews and the use of such processes as least-cost planning and integrated resource planning. Consumer groups have also played a more active role in utility affairs since the advent of rising electricity prices in the early 1970s.

[31] It should be noted that, compared with recent times, consumer groups prior to 1970 were a weak force in initiating requests for rate decreases.

[32] Ronald R. Braeutigam and James P. Quirk, "Demand Uncertainty and the Regulated Firm," *International Economic Review* 25 (1984): 45-60.

[33] Ibid., 47.

would be less binding during periods when the firm's costs are falling and demand is growing, as occurred during the 1950s and 1960s. In fact, during such periods regulated firms sometimes voluntarily lower their prices, presumably to forestall intervention by consumer groups.[34] *If* the ceiling on earnings is not binding, everything else equal, the investment behavior of regulated firms ought to look favorably upon risky technologies. Experience has shown this to be the case.[35]

Bounds on Risk

While regulation restricts the firm's earnings, it also limits the risks the firm faces. Utilities tend to attract conservative investors who are willing to forego capital growth in exchange for reliable dividend payments; few utilities go bankrupt today, and virtually none did so in the 1950s, 1960s, and 1970s. The regulator's attempt to set the allowed rate of return at the firm's cost of capital tends to reduce both the firm's potential for upside gains as well as the potential for downside losses. Limitations on losses play a particularly important role in periods when costs are rising and/or demand is falling. As mentioned above, costs began to rise by the early 1970s, and demand actually fell by 1973; this led utilities to frequently petition for rate "relief." The inevitable processing lags, however, meant that price increases did not keep pace with cost increases, and the financial performance of utilities declined. For example, the ratio of common stock

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[34] Unless managers of utilities perfectly serve the interests of their stockholders, managers will perceive cost padding as more attractive than price reduction as a way to avoid a ceiling on earnings. Price reductions presumably would only occur when cost padding becomes so severe as to be easily observable by consumer groups or a public utility commission.

[35] Most nuclear plants on which substantial amounts of money were spent were ordered before 1972; no nuclear plant was ordered after 1974. Most supercritical coal-fired plants were ordered during the 1960s.

price to book value of assets for a typical utility fell from a high of 2.31 in 1965 to a low of .61 in 1977.[36]

To the extent regulation cushions the firm against risks, everything else equal, it will encourage regulated firms to adopt risky new technologies. Burness, Montgomery, and Quirk[37] have argued that during the mid-1960s (when utility profitability was high), both regulatory risks and bounds on earnings were largely irrelevant.[38] They suggest this may explain the contracting behavior of utilities during the "turnkey era" of nuclear power. During this period in the 1960s, reactor manufacturers attempted to expand sales by shouldering the risk of cost overruns and offering fixed-price ("turnkey") contracts. Nevertheless, many utilities preferred to purchase nuclear power plants under cost-plus contracts. As discussed above, such risk-taking behavior is inconsistent with a model where a ceiling on earnings constrains the firm. Thus, Burness, Montgomery, and Quirk argue that bounds on earnings appear to not have been an important constraint on utilities during this period.

Bounds on risk may affect a utility's choice of a capital/labor ratio.[39] While it is well-known that the A-J effect can lead to overcapitalization when there is a binding

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[36] See Paul Joskow, "Regulatory Failure, Regulatory Reform, and Structural Change in the Electrical Power Industry," *Brookings Papers on Economic Activity: Micro- economics* (1989): 156.

[37] Burness, Montgomery, and Quirk, "Capital Contracting and the Regulated Firm."

[38] This is broadly consistent with the data on rate reviews presented by Braeutigam and Quirk, "Demand Uncertainty and the Regulated Firm," 47, which shows that even during the 1963 to 1967 period, when the percentage of rate cases involving rate decreases was at its maximum, only five of seventeen cases involved rate decreases.

[39] The arguments presented in this paragraph assume a world without retrospective cost disallowances. The threat of disallowances, as discussed later in this chapter, may greatly change the utility's investment strategy.

ceiling on earnings; Lyon[40] has shown that a similar result can occur when both a ceiling and a floor on earnings are present. Suppose a utility can choose between an IGT and a CGT; the two technologies have the same expected costs, but the IGT's construction costs are uncertain, while those of the CGT are known. With an unconstraining rate-of-return ceiling, the utility, as was the case before around 1970, will not overcapitalize when it chooses the CCT (this is the A-J effect). Obversely, the same decision under a constraining rate-of-return ceiling would tend to result in overcapitalization. Suppose instead that the firm considers an IGT--with uncertain construction costs--of exactly the same size as the CGT. If the IGT comes in at lower cost than the CGT, earnings will violate the upper bound (the post-1973/1974 world) and the firm's prices will be reduced to rebate the "excess" earnings to customers. As said earlier, the upper bound on earnings for utilities were pretty much unconstrained before around 1970. Consequently, the cost savings realized by an IGT would pretty much be retained by the utility. If, on the other hand, the IGT comes in at higher cost than the CGT, earnings will fall below the upper bound, and the plant will be less profitable than the CGT. Hence, an IGT of the same size as the CGT cannot possibly be more profitable. This succinctly describes the current environment of electric utilities.

Expected profits from the IGT can only be greater than those from the CGT if the IGT's upside potential is increased, and this can only be accomplished by making the IGT larger than the CGT. Note that the additional upside benefits accrue when construction costs turn out to be *high* rather than low: entering a large expensive plant into the rate base raises profits, but the high construction costs mean the large plant does not violate the rate-of-return constraint. Ironically, it is the possibility of a rate-base-expanding, high-cost outcome that may make an IGT more profitable than a CGT.

If the expanded IGT produces higher expected profits than the original CGT, why doesn't the utility then choose a low-risk CGT of equally expanded size and make even

[40] Thomas P. Lyon, "Regulation with 20-20 Hindsight: Heads I Win, Tails You Lose?" *The RAND Journal of Economics* 22 (1991): 581-95.

more money? This potentially appealing strategy is impossible because, by assumption, the initial CGT was sized to maximize profits given the ceiling on earnings. A CGT built any larger would violate the rate-of-return constraint and bring about a rate decrease. In sum, the net result of combining bounds on earnings with bounds on risk is that whenever the utility prefers an IGT to a CGT, it has incentives to make the IGT excessively large and capital-intensive.

Fuel Adjustment Clauses

Theoretical Arguments

FACs allow electric utilities to adjust their prices when the cost of fuel increases (or decreases) without a formal rate review. Many states instituted FACs to keep the utility financially whole under inflationary conditions in the fuel market. Some economists defend FACs as compatible with the efficient pricing of electricity by providing customers with correct signals of the true economic costs of the electricity they consume.

Critics of FACs contend that automatic passthrough of changes in fuel costs to customers may diminish the incentives of utilities to minimize their overall cost of operations. As discussed below, FACs also can be criticized for biasing a utility's decision toward power purchases from fuel-intensive technologies. The outcome would tend to favor fuel-intensive generation technologies such as combined cycle gas turbine in relation to less fuel-intensive ones.

FACs, as an example, may cause a utility's management to expend less resources in controlling its fuel costs and to overuse fuel relative to other inputs used in the generation of electricity. Consistent with this behavior, for example, utilities would be less likely to operate their base-load power plants at high equivalent availabilities or aggressively negotiate with fuel vendors. As another possible source of inefficiency, FACs may induce an electric utility to substitute fuel for other inputs (for example, labor, capital) needed to generate electricity, even when the total costs of production increase. Some state public utility commissions have recently modified their FACs in recognition of these incentive problems.

FACs may affect a utility's operating, investment, and power purchasing decisions in several ways. First, utilities may devote inadequate resources to maintaining their low-fuel-cost plants and thereby lower plant performance.[41] If so, older and fuel-expensive plants may operate at excessive levels from the standpoint of cost efficiency. In addition, utilities may perceive fewer benefits from new power plants that apply fuel-saving technologies.[42]

Second, utilities may not search aggressively for the lowest cost available fuels or continuously switch fuels when market conditions change. For example, when capital costs are needed to switch fuels, a utility may not undertake cost-reducing actions that increase its financial exposure, especially when all the benefits from such actions flow back to customers.[43]

Third, utilities may overinvest in fuel-intensive plants or, as discussed below, overpurchase power from similar type plants owned by other generators.. This may be particularly the case in today's regulatory environment where utilities generally are

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[41] This assumes that a utility can automatically recover, via its FAC, the replacement costs incurred during a plant outage.

[42] The major reason for this, as discussed below, is the simple fact that FACs transfer the benefits of lower fuel costs to consumers. A discussion of how FACs may induce utilities to adopt conventional technologies rather than renewables (capital-intensive, low fuel-using) technologies is presented in Stanton W. Hadley, Lawrence J. Hill, and Robert D. Perlack, *Report on the Study of the Tax and Rate Treatment of Renewable Energy Projects* (Oak Ridge, TN: Oak Ridge National Laboratory, 1993), 4-10.

[43] Since most FACs distribute virtually all fuel-cost savings to customers, other than to control its retail and wholesale rates and to avoid possible penalties from its commission, a utility may find it more beneficial instead to spend more managerial effort to reduce its nonfuel costs, which are subject to formal rate review.

hesitant toward constructing large or capital-intensive generating facilities because of the risks entailed in retrospective reviews. A utility may decide, partially because of the FAC, to build a more fuel-intensive plant which may be more costly than, say, a large coal plant or large amounts of wind or biomass capacity. While other factors are likely to dominate, the FAC can affect a utility's decision, all other things being equal. Baron and De Bondt,[44] for example, developed a theoretical model that assumes utilities attempt to maximize their present value profits. The authors found that under certain circumstances (for example, the unlikely condition of absolute certainty of fuel prices) a utility would tend to select an inefficient fuel-intensive power plant as well as an inefficient mix of fuels.

Fourth, utilities may not convert their plants to burn a cheaper fuel. If a utility experiences difficulties in getting its capital costs into the rate base, or is allowed a low rate of return, the FAC may induce a utility to defer an economical conversion of its plants.

Finally, FACs would tend to favor most those fuels with the highest price volatility. For example, natural gas may be helped the most from FACs, especially as the natural gas industry undergoes its transition toward full-blown competition.

Although not discussed in the literature, FACs may also affect a utility's decision to purchase power from third parties. Most states allow only the passthrough of energy costs through the FAC; capacity costs in most jurisdictions are recovered in base rates requiring a formal rate review. Since utilities generally make no profit on purchasing power, their objective is to minimize risk. To achieve this a utility may align its purchase power costs so that it can recover the maximum cost through the FAC. What this

[44] D. P. Baron and R. R. De Bondt, "Fuel Adjustment Mechanisms and Economic Efficiency," *Journal of Industrial Economics* 27, (1979), 243-61. Their study did not include any empirical analysis.

implies is that utilities would tend to favor purchased power generated via fuel-intensive technologies, since more of the costs can automatically flow through their FAC. For capital-intensive technologies the utility faces the possibility of being denied full recovery of a major cost component under a retrospective review.[45] Although it is relatively rare for a state commission to disallow capacity costs of purchased power, it is expected that commissions in the future will more closely examine these costs as they grow in size. Commissions will likely scrutinize capacity costs with the same vigor that they have exerted in recent years for construction costs of new power plants.

[45] Given such incentives, utilities would tend to opt for power purchases for which they can recover a higher percentage of the costs through the FAC; lending agencies for the same reason, would prefer NUGs to use more fuel-intensive technologies (assuming other things remain constant). This would bias the decisions of both groups, utilities and NUGs, toward fuel-intensive technologies, assuming no contested recovery of energy-related costs through the FAC. Capital-intensive technologies, some of which may represent least-cost sources, may be "penalized," for example, by the buying utility for their greater risk.

To illustrate the above argument, suppose a utility has two choices: purchase power from a fuel-intensive source at $80 per megawatthour, or purchase power from a capital-intensive source at $70 per megawatthour. From the perspective of economic efficiency, the utility should purchase from the second source since it would save its customers $10 per megawatthour. The utility, however, may consider the second source too risky given the fact that they earn no direct profits. The risk stems from the possibility that the state regulator may disallow, after a retrospective review, the recovery of all capacity costs. For example, the actual cost of the fuel-intensive source may drop to $60 per megawatthour, making the second choice seem imprudent. (It is assumed that the capacity payments of a utility are proportional to the capital intensity of the production technology.) The risk to the utility from the first source may be smaller because a higher percentage of the payments made to the producer can be automatically recovered through the fuel adjustment clause. Again, the outcome would tend to adversely affect capital-intensive innovative generation technologies.

Empirical Evidence

The empirical evidence from studies examining the incentive effects of FACs is inconclusive.[46] The studies generally focused on whether FACs cause electric utilities to overuse fuel in relation to other inputs (that is labor, capital) or whether FACs diminish utilities' financial risk.

All the studies start with the postulate that FACs, by reducing the financial risks of a utility during a period of inflation, make fuel a more attractive input (although Golec finds some evidence to the contrary). Many of the studies make the highly questionable assumption that an electric utility is able to optimize its input mix in the short run when economic conditions change. In reality, since power plants are long-lived, the ability of a utility's management to substitute between fuels and other inputs in the short run is greatly limited.[47] Consequently, the amount of fuel a utility consumes at a given point in time largely depends on past decisions made regarding plant choice.

In one study Scott (1980) examined whether FACs affect a utility's profit level or systematic risk. He found that for the period 1970 to 1975, utilities with FACs experienced smaller profit variances than comparable utilities without clauses. This result implies that utilities may reduce their risks by building more fuel-intensive generating facilities or consuming more fuel in the short run, especially during periods of inflation. Norton (1985) found that FACs shift the

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[46] See, for example, Frank M. Gollop and Stephen H. Karlson, "The Impact of the Fuel Adjustment Mechanism on Economic Efficiency," *Review of Economics and Statistics* 60 (November 1978): 574-84; Paul L. Joskow and Richard Schmalensee, "Incentive Regulation for Electric Utilities," *Yale Journal on Regulation* 4 (Fall 1986): 1-49; Seth W. Norton, "Regulation and Systematic Risk: The Case of Electric Utilities," *The Journal of Law and Economics* 28 (October 1985): 671-86; Frank Scott, "Fuel Adjustment Clauses and Profit Risk" in *Issues in Public Utility Pricing and Regulation*, M. A. Crew, ed. (Lexington, MA: D. C. Heath and Company, 1980); and Joseph Golec, "The Financial Effects of Fuel Adjustment Clauses on Electric Utilities," *Journal of Business* 63, no. 2 (April 1990): 165-86.

[47] The utility has the options of modifying the dispatch order and purchasing more power but use of such options is likely to have an insignificant effect on fuel consumption for the majority of utilities. Only for utilities with significant amounts of both dispatchable capital-intensive capacity and of nonpeaking fuel-intensive capacity is there much leeway for substitution in the short run.

risk of rising fuel prices from utilities to customers. Norton suggests, as did Scott, that a utility may have an incentive to select an input mix that is inefficiently biased toward fuel. Kaserman and Tepel showed that FACs have caused electric utilities to overspend on fuel by about 10 percent.[48]

Gollop and Karlson (1978) tested the hypothesis that FACs cause productive inefficiency: do FACs lead to input bias or waste in the purchasing of fuels? The authors observe that FACs change the utility's "perception" of relative input prices by lowering perceived fuel prices below their market levels. In applying cross-section data for 1971, the study examines the short-run effects of FACs on a utility's decision to substitute fuel for other inputs. Although Gollop and Karlson found no significant fuel bias attributable to FACs, their overall results show that FACs impose less penalty on a utility for inefficient actions, thereby diminishing the incentives for avoiding higher fuel costs.

In sum, the evidence from the literature suggests that FACs may have their strongest effect on the decision of electric utilities to construct more fuel-intensive and less capital-intensive plants for meeting future demand. If so, FACs would penalize such capital-intensive technologies as renewables, coal, and nuclear that consume relatively little fuel. This is true whether a utility builds its own facility or purchases power from a third party.

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[48] D. L. Kaserman and R. C. Tepel, "The Impact of the Automatic Adjustment Clause on Fuel Purchase and Utilization Practices in the U.S. Electric Utility Industry," *Southern Economics Journal* 48 (1982): 687-700. The authors attributed the overspending to the FAC-induced disincentive for utilities to switch to cheaper fuels.

Retrospective Disallowance

The traditional "regulatory bargain," as described above, restricted utilities' potential profits in exchange for reducing their risks.[49] Utilities thus came to expect that any costs that were "prudently incurred" would be passed through to ratepayers. (The "prudent man" standard involves evaluating the quality of a *decision*, given the information available to the decisionmaker at the time; it does not involve assessment of the outcome of the decision.) In the 1980s, however, many nuclear power plants turned out to have costs far beyond initial projections. A number of state public utility commissions responded--with "20-20 hindsight"--by refusing to let utilities charge these high costs to consumers. During the 1980s, regulators disallowed over $15 billion of electric utility costs, the vast majority of which were capital cost disallowances for nuclear plants.[50] Public utility commissions also often argued that even power plants that were prudently built must be "used and useful" if they are to earn a return on investment for the utility. Some took matters a step further and disallowed the difference between the cost of energy incurred by the utility and the actual or projected avoided costs from other sources. For example, in the case of the Wolf Creek nuclear power plant, the Kansas Public Utilities Commission allowed the firm to recover only the costs of a comparably sized coal-fired power plant. In essence, public utility commissions began to punish bad *outcomes* in addition to bad *decisions*. These kinds of "used and useful" reviews are now required by law in some states, and in judicial or regulatory precedent in others.

These changes in regulatory practice substantially altered the "rules of the game" that utilities considered themselves to be playing. One key effect was to undermine the bounds on risk

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[49] As mentioned above, the net effect of the traditional regulatory bargain on incentives to adopt new technologies depends on whether bounds on risk or bounds on earnings are the more important constraint on utilities. The experience with nuclear power, discussed further below, suggests that bounds on risk have traditionally been the more important for electric utilities, and encouraged utilities to adopt new technologies.

[50] Edison Electric Institute, "State Regulatory Risk Factors Associated with Investment in the Next Commercial Nuclear Energy Plant," (Washington, D.C.: Edison Electric Institute, June 1991), Table 1.

that had been seen as an important part of the regulatory bargain. When such a change occurs as a surprise move, it expropriates dollars from existing stockholders, who invested without adequately anticipating such a possibility. It may also increase a utility's cost of capital, since investors perceive an increase in "regulatory risk."[51] Once utilities (and their investors) become aware of the possibility of disallowances not based on strict *ex ante* prudence, the important question is how such policy affects investment decisions.

The conventional view is that retrospective disallowances are harmful because they induce firms to reduce investment and avoid risk.[52] Indeed, recent theoretical analyses by Gilbert and Newbery,[53] Lyon,[54] and Teisberg[55] support the idea that "hindsight review" tends to reduce investment. Furthermore, these studies show that hindsight review causes utilities to delay construction, to invest in smaller projects with shorter lead times, and to be less likely to invest in risky projects. Even if hindsight review does cause utilities to reduce their investment in risky projects with long lead times, however, this is not necessarily harmful. Many have argued that utilities in the late 1970s/early 1980s should have been more attuned to the risks of investing billions of dollars in extremely complex technologies which were subject to large cost changes during construction. In this case, hindsight reviews may beneficially reduce overinvestment and curb utilities' pursuit of unnecessary risks.[56] There are also other arguments for after-the-fact

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[51] For a discussion, see A. Lawrence Kolbe and William B. Tye, "The Duquesne Opinion: How Much `Hope' Is There for Investors in Regulated Firms?" *Yale Journal on Regulation* 8, no. 1 (Winter 1991): 113-57.

[52] See, for example, Charles M. Studness, "Rate Base Disallowances and Future Utility Generating Capacity," *Public Utilities Fortnightly* 118 (September 4, 1986), 33, 35.

[53] Richard J. Gilbert and David M. Newbery, "Regulation Games," Working Paper 8879 (Berkeley, CA: University of California, June 16, 1988).

[54] Lyon, "Regulation with 20-20 Hindsight."

[55] Elizabeth O. Teisberg, "Capital Investment Strategies Under Uncertain Regulation," Working Paper 91-009 (Cambridge, MA: Harvard Business School, August 1990).

[56] Gilbert and Newbery, "Regulation Games," show that in a repeated regulatory interaction, applying the "used and useful" test can overcome the firm's tendency to overinvest, and can

reviews. For example, unless regulators have some ability to engage in retrospective reviews, utilities may lack incentives to work hard to hold down costs and ensure high operating performance. Retrospective reviews, its should be added, mimic the market on the risk side, but not on the reward side.

How does hindsight review affect the firm's choice between different generation technologies? Here there may not be an important difference between disallowances based on the "used and useful" test and those based on the "avoided cost" test. The former are rooted in demand uncertainty, which directly affects the firm's choice of technology. In addition to causing the utility to scale back its investment plans, "used and useful" disallowances would have an effect on the firm's preferences between generating technologies. For example, a utility would have an incentive to build not just smaller plants, but also plants with low capital costs per kilowatt (even if they have higher overall costs); with low capital cost per kilowatt, less capital costs will be at risk in case of a disallowance. The avoided cost test may have a greater differential impact on conventional and innovative technologies because the latter are subject to more uncertainty regarding their costs or operating performance. If regulators apply hindsight review only when new plants require a rate increase (a likely occurrence), risky projects like IGTs will suffer disproportionately. Such reviews, then, may cause utilities to shy away from new technologies.

Again, whether hindsight reviews have *desirable* impacts on technology choice (apart from capacity choice) is not a simple question. As mentioned above, hindsight reviews may beneficially curb utilities' pursuit of large-scale, risky new technologies of any sort. Lyon[57] shows just such an effect in the case where conventional and innovative technologies have the same

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induce it to select an efficient investment path with zero expected profits. Lyon, "Regulation with 20-20 Hindsight," makes a similar argument, as described more fully below. David J. Salant and Glenn A. Woroch, "Trigger Price Regulation," *The RAND Journal of Economics* 23, no. 1 (Spring 1992): 47, go so far as to argue that "each party should be given expanded freedom to respond to opportunistic behavior. By relaxing its obligation to serve, for instance, a firm can react to unremunerative rates by reducing service quality or by abandoning a service altogether. Symmetrically, a regulator could mete out a more severe punishment for inadequate investment if the constitutional ban on confiscatory rates were eased."

[57] Lyon, "Regulation with 20-20 Hindsight."

expected costs, the innovative technology is riskier, and hindsight review disallows the recovery of all costs above the lowest cost *ex post*. The logic is that when the risky project is more profitable, it will tend to be oversized. Since the threat of hindsight review reduces investment, utilities reduce the scale of their risky projects. If the profitability of innovative projects is reduced too far, the utility reverts to using conventional technology. As long as the costs of the conventional technology are unlikely to be disallowed, the utility will not be deterred from investing altogether--it will just stick with the safe technology. When costs are likely to be disallowed, for example through prudence and "used and useful" reviews, this may inhibit economies of scale and any capital-intensive facilities.

If innovative technologies merely have the same expected costs as conventional technologies, nothing is lost if utilities eschew them; in fact, society is presumably better off if unnecessary risks are avoided. If innovative technologies, however, have lower expected costs or other benefits, then regulations that bias utilities toward conventional technologies may be undesirable.[58] This possibility is explored further in the simulation analysis of "Simulation Results."

Implications for Technology Adoption

The key features of regulation described above have a number of implications for technology adoption. Bounds on earnings bias utilities *away* from risky projects, while bounds on risk under limited circumstances may bias them *toward* risky projects. The net effect depends on which constraint is more tightly binding. These predictions are consistent with Mayo and Flynn's[59] empirical study of research and development by regulated firms. They conclude that:

> [T]he results suggest that the net effect of regulation on R&D expenditures will

[58] More precise evaluation of this issue obviously requires careful specification of the risk/reward tradeoff and the risk preferences of affected parties.

[59] John Mayo and Joe Flynn, "The Effect of Regulation on Research and Development," *The Journal of Business* (May 1988).

> depend on whether the rate-of-return [earnings] constraint is binding, on the severity of the constraint, and on the inclusion or exclusion from the rate base of R&D expenditures.[60,61]

An operative bound on earnings will bias the utility toward the use of conventional technology; if not binding, it will instead bias the utility toward risky innovative technologies.[62] Furthermore, when such conditions induce a utility to adopt an IGT, the utility may have incentives to build an IGT that is oversized.[63] Regulatory lag provides limited incentives for cost reduction, especially in periods when costs are increasing. Since the mid-1970s, FACs have become common; these may bias a utility toward fuel-intensive technologies or toward technologies with highly volatile fuel costs. Finally, by the late 1970s and early 1980s, retrospective cost disallowances became a component of electric utility regulation; the threat of such disallowances may help correct the firm's tendency to overcapitalize, but also may cause firms to prefer low-risk

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[60] Mayo and Flynn, "The Effect of Regulation on Research and Development," 335.

[61] The effect of bounds on earnings and risks on *commercial adoption* of IGTs was discussed in Chapter 3. It was observed that bounds on earnings have a stronger effect on discouraging riskier investments.

[62] The first condition, as said earlier, characterizes the environment of electric utilities since around 1973/1974. The second condition existed until the early 1970s.

[63] These arguments may not hold if the lower bound on risk is significantly below the utility's minimum acceptable rate of return.

projects with short lead times and low capital costs per kilowatt even if they have higher expected costs.

The various elements of utility regulation produce different incentives for the adoption of new technologies, and their aggregate effect may be complex. The next two sections move toward an integrated picture of the effect of regulation. The section, "Historical Experience with Innovative Generation Technologies," examines utility's historical experiences with innovative technology under the traditional regulatory bargain of the 1960s and 1970s. Because the experience with hindsight reviews in the 1980s is not as well documented, the section "Simulation Results" uses a simulation model to study the incentives for the adoption of innovative technology when the regulatory bargain includes such reviews.

Historical Experience With Innovative Generation Technologies

The historical record suggests that electric utilities have often been adopters of new technologies. This section reviews the experience of utilities with several innovative technologies: (1) nuclear power, (2) supercritical coal facilities, (3) hot-side versus cold-side precipitators, and (4) forced draft versus balanced draft boilers.

Nuclear Power

Nuclear power is probably the best-known foray by utilities into innovative generation technology:

> Civilian use of nuclear power had its beginnings in the reactor development program of the United States Navy. With the establishment of the Atomic Energy Commission in 1951, attention began to focus on transferring the technology to the civilian power industry. Several early and largely unsuccessful attempts at transfer led to the Power Reactor Demonstration Program (PRDP) in 1955. The PRDP went through several different phases with varying degrees of success. Early projects focused on small experimental reactor types, and only the last phases of the PRDP resulted in construction of commercial scale plants of proved technology that were not built to address significant research questions. . .. It is

> interesting, from the standpoint of commercialization policy, that the two large-scale government-subsidized reactors were not yet operating and were only in the very early stages of construction when large numbers of reactors were ordered in 1963, 1965, and 1966 by private utilities. Although valuable information might have been provided by the experimental programs, no large-scale plant experience was available when technology began to diffuse through the utility industry.[64]

This rush to adopt nuclear power does not support the notion that utilities have consistently avoided new technologies--at least during the era preceding widespread hindsight reviews. One might think that the enthusiasm of utilities for nuclear power was increased because the reactor manufacturers offered new plants on a fixed-price basis (under "turnkey" contracts). Even while turnkey contracts were available, however, some utilities chose to use cost-plus contracts instead, and reactor orders surged after General Electric suspended its turnkey program in June 1966. Perhaps utilities honestly thought the reactor manufacturers had overpriced their turnkey contracts, and expected that cost-plus contracts would be much less expensive. This explanation seems far-fetched, however, since the manufacturers were trying to use turnkey contracts as a tool to expand the market for nuclear reactors. As discussed above, Burness, Montgomery, and Quirk[65] argue that the contracting practices of utilities during this period were due, at least in part, to the regulatory environment that utilities found themselves in from the 1960's to the mid-1970s; namely, an environment of declining nominal costs, high demand growth, long regulatory lag, high market-to-book ratio of utility equity, and strong government encouragement of nuclear power. Overall, the utilities found nuclear power attractive because of the potential to earn high rates of return and the low risks involved during this preretrospective review period.

As is well-known, the eventual cost of many nuclear plants has turned out to be far beyond anything projected in the early 1960s, when it was hoped that nuclear power would be "too cheap to meter." At a minimum, the early U.S. experience with commercial nuclear power

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[64] Zimmerman, "Learning Effects and the Commercialization of New Technologies," 298.

[65] Burness, Montgomery, and Quirk, "Capital Contracting and the Regulated Firm."

shows that regulation--generically and in and of itself--does not necessarily make utilities risk averse, especially in a period when retrospective reviews are minimal and the opportunities to earn higher-than-normal profits exist.

Supercritical Coal

The involvement of electric utilities with nuclear power is paralleled in some ways by their adoption of supercritical coal generation technology. "Supercritical" technology refers to units using temperature and pressure high enough that "water vaporizes directly to dry superheated steam and does not go through a boiling/saturated steam stage."[66] This new technology continued the evolution of coal-fired steam generating units toward larger plants with higher steam pressures. From 1970 to 1974 supercritical units were the most common coal-fired generators built by utilities. By the late 1970s, when retrospective reviews started to occur, however, utilities were backing away from supercritical technology and it was virtually abandoned by the mid 1980s. Joskow argues that the disappointing economics of supercritical technology were due to a combination of poor reliability, low thermal efficiency, high construction costs, and low growth in electricity demand; all of these factors tended to counteract the scale economies in the construction of large units.[67] As in the case of nuclear power, utilities proved themselves willing to adopt an innovative technology, with costly results in several cases. Taken together, the industry's unfortunate experiences with these two generation technologies suggest that scale-augmenting technological advances in power generation ended sometime during the early 1970s.

Hot-Side Precipitators

[66] See Paul Joskow, "Productivity Growth and Technical Change in the Generation of Electricity," *The Energy Journal* 8, no. 1 (1987), 21.

[67] Ibid., 36.

In addition to the adoption of entirely new generation technologies, utilities have been innovative in altering the design features of existing generation technology. One example is the attempt to meet emission requirements more efficiently by moving electrostatic flue gas precipitators from the cold side to the hot side of the air heater. "During the late 1960s and early 1970s, state-of-the-art technical information and overall economics supported the selection of hot-side precipitators over the previously popular option of cold-side precipitators. Many utilities that selected this seemingly logical option are now experiencing unanticipated operational and structural problems with the hot-side precipitators. . .. Extensive cracking of the steel in high stress areas has been documented in hot-side precipitators at several power plants around the country over the past five years."[68] Correcting the problem can be costly. For example, Houston Lighting and Power Co. recently spent $179 million to convert the precipitators at three power plants from the hot side to the cold side. Other utilities that have converted plants from hot- to cold-side precipitators include Wisconsin Electric Power, Arkansas Power and Light, San Antonio City Public Service Board and Iowa Public Service.[69]

Forced Draft Boilers

Another innovation adopted by many utilities in the late 1960s and early 1970s was the "forced draft" boiler (also referred to as a pressurized boiler) which used input fans to force air into the boiler; the main competitor was the "balanced draft" boiler, which used large exhaust fans as well as input fans. Forced draft technology was often used in supercritical generating plants, but the two technologies could be used independently. The forced draft design was adopted because it was thought to have lower capital costs, a lower cost of auxiliary power, and less maintenance for exhaust fans. It did not always perform as expected, however:

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[68] R. L. Schneider and O. Zaben, "Structural Integrity Assessment of Embrittled Structural Steel in Hot Precipitators," *Proceedings of the American Power Conference*, Vol. 52 (1989), 326.

[69] "Hot-Side Precipitators May Need Drastic Retrofits," *Electrical World* (July 1988): 68-70.

> Experience with forced draft boilers has demonstrated a set of problems. Due to the pressure differential, joints and seams leak. If large enough, such leaks can induce forced outages. The leaks cause soot and ash to be leaked outside the boiler, which induces numerous maintenance problems, including instrumentation malfunctions. The flow distribution of ash within the boiler is also altered by leaks. This can cause accelerated wear of tubing and loss of insulation. According to our sample of utilities, the net effect of these incidents is estimated to reduce the equivalent availability of a unit by four to six percent, compared to a balanced draft design.[70]

A number of utilities have converted to balanced draft boilers, at costs of $30 to $50 million. It is unclear exactly how many utilities have taken this step, but one consulting firm reports that "all [utilities] interviewed have converted some units [to balanced draft] except American Electric Power and Detroit Edison."[71]

In sum, from the 1960s through the mid-1970s, utilities adopted a variety of different technological innovations, many of which have produced disappointing results. This risk-taking behavior is consistent with the argument made earlier in this chapter that bounds on utility risks during the 1960s and early 1970s were low relative to the potential for utilities to earn high earnings from successful innovations. These examples, however, do not shed light on utility decisionmaking in the late 1970s and 1980s under threat of hindsight review. Since this more recent experience is less well documented,

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[70] Science Applications, Inc., *Case Studies of Electric Generating Plant Demographics: Efficiency and Availability Enhancements* (McLean, VA: Science Applications, Inc., January 1983), 34.

[71] Ibid.

the next section utilizes a simulation analysis to gain insight into the effects of hindsight review.

Simulation Results

This section presents results from a simulation model that integrates the elements of regulation discussed in Chapter 4 and highlights some of their key effects on technology adoption. A principal finding is that hindsight disallowances can influence a utility to choose a CGT with higher expected costs (cost per levelized kilowatthour) over an IGT with lower expected costs but less predictability in construction costs. This result has ramifications for the development of targeted incentives for promoting IGTs. The second incentive system presented in Chapter 7 illustrates how regulation can overcome the problem of utilities rejecting potentially economical IGTs.

The regulatory environment in the model features the combined effects of bounds on earnings and risk, in conjunction with retrospective cost disallowances. To keep the focus on the differences between IGTs and CGTs, the demand curve is assumed to be fixed, and hindsight review does not apply the "used and useful" test; instead, hindsight review disallows the recovery of costs above the lowest avoided cost *ex post*. The difference between the two available technologies comes in terms of their construction costs: the firm can choose a CGT with known construction costs or an IGT with costs that are uncertain but are less than or equal to the cost of the CGT in expected value terms. The sequence of events in the model is as follows:

1. The regulator sets a price and a hindsight review policy.
2. The utility selects a technology (CGT or IGT), and chooses levels of capital (K) and variable factors (L).
3. The construction cost of the IGT is observed.

4. If the utility's earnings are inadequate or excessive, a rate review is initiated and new rates are set.[72] Depending on the policy set by the regulator, hindsight review may be incorporated into the rate review.

Functional forms and numerical parameter values were chosen to provide a reasonable simulation example; they are not intended to represent the situation of any real utility, nor do they necessarily reflect accurately the costs of conventional or innovative technology. Precise numerical results, however, are not the point of the exercise. Instead, the goal is to reveal the important qualitative kinds of behavior that may occur under public utility regulation, especially with regard to the application of hindsight reviews. These patterns are likely to be robust to changes in parameter values or functional forms.

For clarity, the general assumptions employed in the model are outlined briefly below (more detail can be found in Appendix C). First, the demand function assumes a constant elasticity. Second, the production function exhibits scale economies, but the optimal capital/labor ratio is independent of the generating plant's scale.[73] Third, perhaps the most important role of the simulation is to allow for numerical analysis of a specific probability distribution: expectations about the future construction costs of the IGT are represented by a subjective probability density function that is lognormal. All parameter values are based on coal-burning steam plants, which account for over half the electricity produced in the United States.[74]

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[72] This assumption corresponds to the environment faced by utilities after the 1973/ 1974 oil embargo period.

[73] In technical terms, the production function is homothetic. See S. E. Atkinson and R. Halvorsen, "Interfuel Substitution in Steam Electric Power Generation," *Journal of Political Economy* 82 (October 1976): 959-78, for empirical work supporting this assumption for the case of electric power generation.

[74] See Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry 1988*, no. 56 (Washington, D.C.: Edison Electric Institute, November 1989), 30.

Three tables are presented below. The first, Table 4-1, provides a bench-mark case where there is no hindsight review and the expected costs of the CGT and the IGT are equal. The table shows how the utility's investment choices change as the expected cost of construction rises. Table 4-2 replicates part of Table 4-1, but adds the possibility of hindsight review, still assuming the CGT and IGT have equal costs. Finally, Table 4-3 examines the effects of hindsight review when the IGT has lower expected costs than the CGT.

Table 4-1 shows the effects of varying the expected construction cost per megawatt, holding output price constant. (Hindsight review is not reflected in Table 4-1.) The first column gives the regulated retail price of electricity, and the second gives the expected construction costs in millions of dollars per megawatt. The firm's choice of capital stock is shown for three cases: a CGT and an IGT under rate-of-return regulation, and a bench-mark, cost-minimizing level. For each level of expected costs, the firm chooses either the CGT or the IGT, depending on which generates greater profits; the firm's choice of capital stock can then be compared to the cost-minimizing level to determine whether or not the firm overinvests in generation capacity. For low construction costs (rows 1-4) or intermediate construction costs (rows 5-7), the utility earns greater profits from the CGT than the IGT; the reverse is true for high construction costs (rows 8-10). Note that compared to the cost-minimizing outcome the utility overcapitalizes for low construction costs (as in rows 1-4, when it chooses the CGT) or high construction costs (as in rows 8-10, when it chooses the IGT); its selection of capital stock is efficient for intermediate cost levels (rows 5-7). As discussed earlier, whenever the utility prefers an IGT it overcapitalizes, under the conditions used in the model, for example, no retrospective hindsight review and tight profit constraints. The efficient capital stock is chosen only if costs are so high that bounds on earnings are not binding when the utility selects a CGT. If costs rise higher still, however, the utility switches form the CGT to the IGT and overcapitalizes.

Table 4-2 illustrates the effects of hindsight review, again assuming the CGT and the IGT have equal expected costs. It is assumed here that hindsight review is only triggered when the utility petitions for a rate increase, which typically occurs when actual

TABLE 4-1

COMPARISON OF INNOVATIVE AND CONVENTIONAL TECHNOLOGY WHEN EXPECTED COSTS ARE EQUAL AND THERE IS NO HINDSIGHT REVIEW

			CGT		IGT		Cost Minimizing
ρ_0 (cents/kWh)		Expected Cost ($M/MW)	Capital (MW)	Profits ($M)	Capital (MW)	Profits ($M)	Capital (MW)
5		0.5	**2459***	61.5	1990	30.4	1288
5	Low	0.6	**2022**	60.6	1850	30.0	1231
5	Costs	0.7	**1696**	59.4	1640	29.2	1184
5		0.8	**1432**	57.3	1500	28.2	1145
5	Inter-	0.9	**1112**	54.1	1400	27.0	1112
5	mediate	1.0	**1083**	43.1	1330	25.7	1083
5	Costs	1.1	**1058**	32.4	1280	24.3	1058
5		1.2	1035	21.9	**1250**	22.9	1035
5	High	1.3	1014	11.7	**1220**	21.4	1014
5	Costs	1.4	996	1.6	**1200**	20.0	996

Source: Reproduced from Lyon, "Regulation with 20-20 Hindsight."

* Shaded capital choices indicate the utility's profit-maximizing investment for each level of expected construction costs.

TABLE 4-2

THE EFFECTS OF HINDSIGHT REVIEW ON CONVENTIONAL AND INNOVATIVE GENERATION TECHNOLOGY

		CGT		IGT			
				No Hindsight		Hindsight	
ρ_0 (cents/kWh)	Expected Cost ($M/MW)	Capital (MW)	Profits ($M)	Capital (MW)	Profits ($M)	Capital (MW)	Profits ($M)
5	0.8	**1432***	57.3	1500	28.2	1150	19.9
5	1.0	**1083**	43.1	1330	25.7	1050	11.7
5	1.2	**1035**	21.9	1250	22.9	1000	0.8
5	1.4	**996**	1.6	1200	20.0	0	0

from Lyon, "Regulation with 20-20 Hindsight."

* Shaded capital choices indicate the utility's profit-maximizing investment for each level of expected construction costs.

TABLE 4-3

EFFECTS OF HINDSIGHT REVIEW WHEN INNOVATIVE TECHNOLOGY IS RISKIER BUT CHEAPER THAN CONVENTIONAL TECHNOLOGY

		CGT		IGT			
				No Hindsight		Hindsight	
ρ_0 (cents/kWh)	*E(c)* ($M/MW)	*K* (MW)	π ($M)	*K* (MW)	$\bar{\pi}$ ($M)	*K* (MW)	π ($M)
4	1.2	0	0	1440	18.8	**0**	0
4	1.4	0	0	1440	18.8	**1220**	3.5
4	1.6	0	0	1440	18.8	**1270**	7.6
5	1.2	**1035**[*]	21.9	1330	25.7	1050	11.7
5	1.4	996	1.6	1330	25.7	**1120**	11.8
5	1.6	0	0	1330	25.7	**1140**	15.5
6	1.2	**951**	53.0	1310	31.0	1000	22.1
6	1.4	**917**	34.3	1310	31.0	1000	22.1
6	1.6	886	16.3	1310	31.0	**1000**	22.1

Source: Reproduced from Lyon, "Regulation with 20-20 Hindsight."

[*] Shaded capital choices indicate the utility's profit-maximizing investment for each level of expected construction costs.

costs turn out to be higher than expected costs.[75] Conventional technology, with its well-understood costs, does not, in this simplified example, pose the same magnitude of risk of unexpectedly high costs as innovative technology does. Thus, the threat of hindsight review is

[75] As a general rule, the utility requests a rate increase anytime the cost of the added facility, whether conventional or innovative or whether actual costs turn out higher or lower than expected, increases it average cost of service.

assumed to have no effect on CGTs, but imposes extra risks on IGTs. For low or intermediate construction costs (rows 1-2), hindsight review has no effect on the firm's investments, since the firm chooses the CGT with or without hindsight review. For high construction costs (rows 3-4), however, hindsight review causes the utility to reduce its capital investment and switch technologies. To see this, note that without hindsight review, the utility in these high-cost cases would select an IGT, which Table 4-1 shows would be oversized. Hindsight review reduces the profitability of the IGT to the point where the utility switches from the oversized IGT to a smaller CGT, which Table 4-1 shows is of efficient scale. Note that in rows 3-4 if the utility were for some reason unable to switch to the CGT, hindsight review would cause it to reduce the size of its IGT investment *below* efficient scale, and possibly cause it to cease investing altogether.

Table 4-3 examines the effects of hindsight review when the IGT has lower expected construction costs (held constant at $1 million per MW throughout the table) than does the CGT.[76] If electricity prices are low (rows 1-3), the CGT would be unprofitable and the utility would refuse to build such a plant. Nevertheless, because the IGT has lower expected costs, the utility may be willing to invest in IGT even at low electricity prices. Hindsight review reduces the scale and profitability of the utility's investment, and may cause the utility to abandon investment altogether (row 1). If electricity prices are moderate (rows 4-6), the CGT's profitability is improved, but the IGT is still more profitable if there is no hindsight review. With hindsight review, however, the utility may switch to the CGT (row 4) if its costs are low enough. Finally, at high electricity prices (rows 7-9) the utility prefers the CGT if its construction costs are not too high (rows 7-8). If the CGT's construction costs are too high (row 9), however, the utility prefers the IGT even in the presence of hindsight review.

Key Points from the Simulation

The simulation results show that many different scenarios for technology adoption may arise under regulation, depending on the stringency of regulated prices, the relative costs of CGT

[76] This case is not considered in Lyon, "Regulation with 20-20 Hindsight."

and IGT, and whether or not hindsight review is applied. This variety of possible results cautions against drawing overly simple conclusions. Nevertheless, several important points are worth highlighting. Without hindsight review, the conventional technology is preferred to the IGT when both have low expected costs. The CGT with its predictable costs can be sized to "lock in" the allowed rate of return, and the extra risks of the IGT are not worth pursuing; in this case, bounds on earnings outweigh bounds on risk. When both technologies have high expected costs, however, then the CGT is not very profitable and the IGT--which at least offers some upside potential because it may come in less expensive than the CGT--may be preferred by the utility. Even if the CGT is so unprofitable the utility would refuse to build it, an IGT with equal expected costs may still be undertaken.

When hindsight review is added to regulatory practice, it imposes extra risks on IGTs by increasing the costs to the utility if an IGT investment goes sour. This greater risk has several effects. First of all, it causes the utility to reduce its capital investment in any IGTs it undertakes, in an attempt to reduce the risk to which it is exposed. Second, because hindsight review reduces the profitability of IGTs relative to CGTs, the utility may switch from an innovative to a conventional technology, *even if the latter has higher expected costs*. Third, if expected costs are high enough that the utility is unwilling to build a CGT, then hindsight review may cause the utility to cease making new generation investments altogether, inducing it to rely on purchased power instead. These expected outcomes of hindsight review seem to be compatible with utilities' behavior over the last several years.

Overall Effects of Regulation on the Adoption of IGTs in the 1990s

What is the net effect of regulation as of 1993? Three main considerations stand out. First, utility financial performance is considerably stronger than at its low in the late 1970s and early 1980s, but has not approached the levels of the 1960s. For example, market/book ratios have been above one since 1985, though they have not come close to two, which they surpassed in the 1960s. Around the mid-1980s Wall Street was starting to tell utilities that they would be downgraded if they built new generation facilities, especially large, capital-intensive ones. The net effect of recent regulatory decisions regarding ceilings and floors on earnings is that utilities should have greater incentives to adopt IGTs today than the late 1970s and early 1980s, but less incentive than what they had during the early 1970s and prior periods. During the latter period, conditions were favorable to IGTs (as argued by Burness, Montgomery, and Quirk[77] and earlier in this report. Second, the continuing presence of FACs in most states may bias utilities toward fuel-intensive plants and, more specifically, plants that use fuels with relatively volatile prices. Third, and most importantly, hindsight reviews have become common, undercutting loss limitations and imposing new risks. According to Joskow,[78] "[C]ost disallowances for generating facilities have become routine, while changes in the ratemaking process to account for the increased risk of disallowances have not been forthcoming. . .As a result, the expected return on investments in new generating plants subject to regulation is perceived to be below the cost of capital."[79] This effect is exacerbated for technologies with uncertain construction costs or operating characteristics, as shown earlier in this chapter.

Given the available array of generation technologies, the effects of hindsight review and FACs appear to reinforce one another, and outweigh any remaining bounds on risk. The net effect of regulation, then, is to favor technologies such as natural gas combustion turbine or combined-cycle (small, fuel-intensive, employing a fuel with volatile prices) as opposed to coal-fired plants (larger, more capital-intensive, with more stable fuel prices), nuclear plants (very large, highly capital-intensive), or renewable technologies such as solar thermal photovoltaic (extremely capital-intensive). (This should not be interpreted to imply that other factors do not affect the economics of any or all of these

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[77] Burness, Montgomery, and Quirk, "Capital Contracting and the Regulated Firm."

[78] Joskow, "Regulatory Failure, Regulatory Reform, and Structural Change in the Electrical Power Industry."

[79] Ibid., 161.

technologies; nor to say that natural gas would not be the correct choice in some or most cases in the absence of these disincentives.) This conclusion is consistent with Joskow's observation that "Few utilities appear willing to build large base-load facilities, even in areas where additional capacity is needed. Instead, they are looking to third parties, smaller and less capital-intensive generating technologies, and investments in customer conservation to reduce the financial risks."[80]

Existing State Incentives for IGT Adoption

In recognition of the need to develop environmentally cleaner and more energy efficient generation, many states have instituted monetary and tax incentives for IGTs. The focus of the incentives is generally to boost research, encourage development and demonstration of environmentally benign innovative technologies, and facilitate energy generation. A few states also offer regulatory incentives that are either directly or potentially applicable to IGTs. Most of the regulatory incentives generally apply to development efforts for IGTs and are not intended to directly address the regulatory barriers to IGT adoption identified in this report. More information on the state incentives for IGT adoption can be found in the references listed below.[81,82]

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[80] Ibid., 161-62.

[81] For a comprehensive overview of state monetary, tax, and regulatory incentives for CCTs, see Mohammad Harunuzzaman, *Commercialization of Clean Coal Technologies: An Examination of Issues and Status of Current Tax, Monetary, and Ratemaking Incentives*, prepared for the U.S. Department of Energy, December 16, 1993.

[82] For detailed information on state monetary and tax incentives for IGTs, see National Association of State Development Agencies (NASDA), *Directory of Incentives for Business Investment and Development in the United States: A State-By-State Guide*, 3rd edition (Washington, D.C.: The Urban Institute Press, 1991).

Emerging Regulatory and Industry Trends and Innovative Technologies

New Technologies and the SO_2 Allowance Trading System[83]

Title IV of the Clean Air Act Amendments of 1990 (CAAA) established a national emission allowance trading system. The allowance trading system is a market-based form of environmental regulation designed to reduce and limit sulfur dioxide (SO_2) emissions. The reduction in SO_2 is to occur in two phases: phase I begins in 1995 and affects 110 larger plants that have a relatively high emission rate;[84] phase II begins in 2000 and affects nearly all units that produce electricity over 25 MW. In phase II affected units will receive an allocation of allowances up to 1.2 pounds of SO_2 per mmBtu, in most cases based on their fuel consumption in the period 1985 to 1987.[85] Each allowance is equal to one ton of SO_2 per year. Existing sources may exceed this emission rate, but must have allowances to cover that excess over their allocation of allowances.[86] Unless specifically named in title IV, new sources will not receive an allocation of allowances and must either purchase them or shift them from existing sources in their system.

The allowance trading system allows utilities considerable flexibility in finding a means to

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[83] This discussion is adapted from Kenneth Rose, "Regulatory Treatment of Allowances and Compliance Costs: What's Good for Ratepayers, Utilities, and the Allowance Market?," in *Regulatory Policy Issues and the Clean Air Act: Issues and Papers from the State Implementation Workshops*, edited by Kenneth Rose and Robert E. Burns, The National Regulatory Research Institute, Columbus, Ohio, NRRI 93-8, July 1993.

[84] In general, this includes units over 100 MW and with emissions over 2.5 pounds of SO_2 per mmBtu. These units were specifically named in Title IV of the CAAA. The title also specified the number of allowances these sources will receive, which was based on the emission rate of 2.5 pounds.

[85] Sources below 1.2 pounds will receive an allocation based on their actual emissions plus, in most cases, a bonus.

[86] Sources cannot exceed the National Ambient Air Quality Standards (title I of the CAAA) regardless of the number of allowances they hold. See Chapters 1 through 3 of Kenneth Rose et al., *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program* (Columbus, OH: The National Regulatory Research Institute, May 1992), for more detail on Title IV of the CAAA.

comply with the CAAA. New and existing technologies, purchases of allowances, and fuel switching, are some of the options available. While some changes may occur, phase I affected utilities have chosen their compliance actions. Most units are using fuel switching and blending to comply (122 units). Twenty-six units are using wet FGD and, currently, only eight unit (two utilities) are using allowances to comply with phase I.[87] There has been little unsubsidized use of CCTs as yet, largely because most CCT demonstrations have yet to be completed. Trading of allowances has occurred since early 1992 and there have been about twenty publicly announced private trades. The price of allowances in these recent trades has been about $200.

An important consideration is that the allowance trading system is being primarily applied to an economically regulated electric utility industry. A question that has been raised is whether current public utility commission rules and procedures provide sufficient incentives to utilities to minimize their compliance costs. Some have argued that some changes are required to current regulatory practices if the full potential of the allowance system is to be realized. This is because the allowance system and the choice of options now available to utilities provide utilities an opportunity to significantly lower compliance costs than what would have occurred with command-and-control environmental regulation. There may be little incentive, however, to use the allowance market and minimize compliance costs with traditional ratemaking methods or attempt to use a new and innovative approach to compliance.

Traditional Ratemaking Treatment of Allowances and Compliance Costs

Of particular concern is the ratemaking treatment of allowances and compliance costs. Under a traditional regulatory approach, prudent investments in capital equipment, such as scrubbers and plant modification for fuel switching, would be added to the rate base. Any revenue from the sale of allowances "freed up" because of a ratebased investment may, under this approach, be deducted from the asset value in the rate base. For example, if the compliance strategy involved a scrubber and if the investment is included in the utility's rate base, then the

[87] Koby Bailey, Argonne National Laboratory, personal communication, October 1993.

proceeds from the sale of allowances freed due to overcompliance would offset the cost of the scrubber in rate base. This is because ratepayers, in effect, provide the source of funding for the pollution abatement facilities by providing a return on the utility's prudent investment in those facilities. Any additional return to the utility from the facilities should benefit the ratepayers through a deduction from the utility's rate base of the gains from the sale of allowances. A commission could maintain this regulatory approach until the utility's pollution control facilities in rate base become zero.

Some compliance options require little or no capital investment, such as fuel switching or purchasing allowances. Again, under a traditional regulatory framework, the higher price for low-sulfur coal can be accounted for as an increase in operating cost in a rate case and these higher costs passed through an existing FAC. Since purchased allowances are "used up" along with the fossil fuel (or stored or "banked") for future use, used allowances may analogously be treated as an operating expense for ratemaking purposes.

Any ratemaking approach will have a profound effect on the decisionmaking process of a utility and may bias, perhaps unintentionally, the utility's investment decisions. A traditional ratemaking treatment may introduce an unintended bias in favor of compliance options that are not necessarily the lowest cost solution. Some have argued that if the commission commits to placing large capital expenditures in rate base, a utility's decision will be biased toward scrubbers, even though this may not be the lowest-cost option.[88] Counteracting any capital bias is the possible utility reluctance to invest in large capital projects because of past disallowances. This may result in the utility taking only short-term actions (such as purchasing fuel) and foregoing more capital-intensive (and more uncertain) options which may have long-term benefits to the utility and its ratepayers.

Under certain conditions (primarily when the rate of return exceeds the cost of capital--a condition which appeared to occur until roughly 1973 but perhaps not since then), a bias toward

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[88] For further discussion of this point, see, Rose, *Public Utility Commission Implementation*, specifically Chapters 3, 7, and 9. Also see, Douglas R. Bohi and Dallas Burtraw, "Utility Investment Behavior and the Emission Trading Market," *Resources and Energy*, 14 (1992): 129-53.

large capital expenditures is possible. In addition, if the initial allowances earn no return but the commission states up front that large capital expenditures for compliance, such as scrubbers, will be ratebased, a great deal of the uncertainty associated with that decision (whether it will be ratebased) is removed. All state commissions except one (with few jurisdictional generating facilities) allow pollution abatement investment into rate base.

Therefore, if there is a virtual guarantee that the investment will be ratebased, that initial allowances will not be, and that the sale of any allowances will be used to deduct the value of the pollution control asset, then the profit-maximizing firm will tend toward large capital investments and will sell or bank excess allowances. The decision on how many to sell and convert to cash and how many to bank will depend, in part, on the utility's rate of return on capital and the anticipated reaction from the commission to the utility's decision. Ideally, the utility would base its sell/bank decision on its forecast of its own future need and expected future cost of allowances and fuels and not on a distortion created by the ratemaking treatment.

Another example is the unintended bias that could arise from an FAC that could bias the utility toward a fuel-switching option. If future cost increases in low-sulfur coal are allowed to be passed through to ratepayers, then utilities may favor fuel switching (to low-sulfur coal), even though this is not necessarily the lowest cost option.[89] This assumes that the utility believes that it could not recover its costs, including costs of money associated with the least-cost option.

Incentive Treatment for Allowances and Compliance Costs

An alternative ratemaking treatment recognizes that traditional methods may have some limitations when applied to implementing the CAAA. Moreover, these traditional methods are currently under reevaluation themselves due to, among other reasons, the lack of the incentive

[89] For a general discussion of the limitations of FACs see Chapter 5 "Fuel Adjustment in a More Open Market Environment," in Robert E. Burns, Mark Eifert, and Peter A. Nagler, *Current PGA and FAC Practices: Implications for Ratemaking in Competitive Markets* (Columbus, OH: The National Regulatory Research Institute, 1991).

given to utilities to minimize their operating costs.[90] In response, regulators in the United States and abroad have increasingly turned to incentive- or market-based mechanisms, such as price caps, performance incentives, and competitive bidding, to avoid the limitations thought to occur with traditional regulation. A market-based ratemaking treatment of this general type can also be developed for allowances and compliance cost. The alternative to these and other traditional approaches are market-based or incentive-type mechanisms.

An incentive or market-based mechanism can be developed to encourage utilities to minimize their SO_2 control costs. The primary advantage that a market-based mechanism has over a traditional method is that it provides the utility with more incentive to be cost efficient.[91] This includes reducing the utility's operating and capital costs through improved efficiency, allowance purchases and sales, or using innovative technologies. An incentive-based mechanism would reward a utility in the long run for good performance within its control (that is also in the interest of ratepayers) and penalize it for bad performance within its control. This increases the utility's motivation for adopting innovative and cost-effective approaches when developing a compliance strategy.

An incentive mechanism for SO_2 control costs could consist of the commission setting a bench mark value for allowances, similar to a price cap, that the utility's actual control cost could then be measured against. If the utility is able to outperform this bench mark, it is allowed a share of the difference between the actual control cost and the bench mark. If the control cost is above the bench mark, the utility either recovers only the bench mark or some predetermined portion of the difference. Symmetry may require that the same proportion be used for a "gain" (the difference between the bench mark and control cost when the control cost is lower) as for a "loss" (the difference between the bench mark and control cost when the control cost is higher).

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[90] Five often-cited limitations to traditional ratebase/rate-of-return regulation are reviewed in Kenneth Rose, "Price-Cap Regulation: Some Implementation Issues," *NRRI Quarterly Bulletin* 12, no. 4 (December 1991).

[91] For a discussion on this point and analysis of different types of incentive mechanisms, see, Paul L. Joskow and Richard Schmalensee, "Incentive Regulation For Electric Utilities," *Yale Journal on Regulation*, 4, no. 1 (Fall 1986).

The bench mark can be set in one of at least three ways utilizing: (1) the utility's expected control cost, (2) an estimated value of allowances, or, eventually when more market information is available, (3) the market price of allowances. Each method, of course, has its own advantages and disadvantages.

The bench mark can be posted in advance and the utility given reasonable assurances that it will be applied objectively. The bench mark could be set and adjusted annually at the beginning of the year during, for example, EPA's true-up period. At the end of the year or some other period, the difference would be calculated and future rates adjusted accordingly. (Alternatively, the commission could set the bench mark periodically and, rather than track the control cost, simply use it as the basis for the utility's compliance cost recovery.)

Under this approach, the commission does not prescribe or approve the specific control technology planned or used by the utility. The utility's reward is based on its own control cost and the price of allowances, a factor external to the firm and beyond its control. As a result, the lower it is able to reduce its control costs (below the market price), the greater its reward. This increases the incentive to reduce costs by adopting or developing innovative technologies and operating in an efficient manner.

The New Energy Legislation and Innovative Generating Technologies

The Energy Policy Act of 1992 (EPAct) was signed into law by President Bush on October 24. Most experts view the Act as significant legislation that will have a fundamental effect on the future structure and performance of the electric power industry. Most importantly, the Act should promote competition in wholesale power markets. It will allow more future power generation, for example, to fall outside the jurisdiction of tight state price regulation. The major provisions of the Act amended the Public Utility Company Act of 1935 (PUHCA) and the Federal Power Act (FPA).

As its major objective, the new PUHCA removed entry barriers to wholesale power producers. It opens the way for nonutility companies to participate as wholesale power producers and utilities to produce power from new generating facilities outside of their retail service areas. With approval from state commissions, utilities can also spin off existing ratebased facilities as exempt wholesale facilities. Overall, the changes in PUHCA should expand the role of wholesale generating facilities in the electric power industry. The growth of these facilities will hinge on the rate at which the future demand for electricity exceeds the combination of existing generating capacity plus conservation and load-management investments, minus power plant retirements.

Both state and federal commissions will influence the profitability and marketability of new wholesale facilities, including those applying new technologies.[92] State commissions will play an important role in affecting the incentives of utilities to purchase power as well as indirectly the profit-risk environment faced by wholesale power producers. By giving its approval of provisions contained in power sale contracts, for example, a state commission will influence the profit and risks of wholesale power as well as the availability of capital funds for new projects (see Chapter 5 of this report). State commissions also will affect the outcome of power procurement bids by the discretion allowed utility buyers in selecting, and negotiating with, producers.

It is expected that state commissions will be favorable toward the general principles underlying the rationale for a new PUHCA and easier transmission access: more

[92] See, for example, Kenneth W. Costello, Edward H. Jennings, and Timothy W. Viezer, *Implications of a New PUHCA for the Electric Industry and Regulators* (Columbus, OH: The National Regulatory Research Institute, 1992).

competitive wholesale power markets will allow vertically integrated and other utilities to choose from more suppliers, thereby promoting state sanctioned least-cost planning and traditional regulatory objectives. State commissions also may tend to encourage utilities to "buy rather than build," since the risks of new plant construction and operations typically would shift from consumers to "unregulated" producers.

State commissions, on the other hand, will generally be opposed to utility-affiliate transactions that reflect anticompetitive activities or in any way harm the interests of retail consumers. For example, commissions may oppose the spinning off of existing ratebased generating facilities. In the situation where a facility is providing a utility with small profits, the utility may expect to earn higher profits from spinning off a facility into wholesale power market and receiving FERC approval for market-based prices. Consequently, the utility may be more willing to repower using a new IGT technology since it no longer would be subject to the tight profit constraints of rate-of-return regulation. A state commission might oppose spinning off existing facilities unless consumers are adequately compensated, for instance by having the utility subsidiary pay a price above the depreciated book value to consumers, on grounds that they would lose the future benefits of the facility that they, in effect, previously paid for during the early years of the facility's life. (Under rate-of-return regulation, a utility recovers a disproportionate portion of capital expenditures during the early years of plant operation.)

State commissions also may not look favorably upon self-dealing transactions. The amendments to PUHCA give state commissions the discretion whether or not to approve self-dealing transactions involving an exempt wholesale generator and an affiliated utility. Many commissions may come to view the risks from self-dealing abuse as too great relative to the potential benefits. Even with a least-cost planning process in place or the ability to conduct a retrospective review, commissions would still have to monitor self-dealing transactions closely. The informational problem associated with detecting self-dealing abuse may provoke some commissions to prohibit power transactions between affiliated entities. Some commissions, on the other hand, may allow self-dealing transactions under the auspices of an incentive-based regulatory system that eliminates any benefits to transacting parties from abuses.[93]

While prohibiting self-dealing could obstruct the development of new utility-affiliated subsidiaries, it could expand the market for true independent power producers.[94] Since the FERC would be more inclined to approve market-based pricing for true independent producers, prohibiting self-dealing (assuming other things remain the same) may create more incentives for innovative technologies.

While actions by state commissions that hinder the development of wholesale power markets can oftentimes be easily detected, determining whether they constitute uneconomic obstacles is a more difficult matter. For example, emphasis on utility demand-side management activities, a "no profit incentive" policy for power purchases, might be considered obstacles to the development of wholesale power facilities. Yet, one may argue that they would not necessarily produce uneconomical outcomes (for example, outcomes that are detrimental to long-term consumer interests). Only when such outcomes occur would existing regulatory actions constitute uneconomic barriers.

The prices charged by wholesale power facilities fall under the auspices of the Federal Energy Regulatory Commission (FERC). The Commission has increasingly allowed market-based pricing for unaffiliated transactions where the producer has limited opportunities to exercise market power.[95] The FERC has issued rules that would provide general guidelines on conditions acceptable for market-based prices. The rules would provide a "safe harbor" for producers with transmission facilities willing to offer

[93] One such system is price-cap regulation, where the regulated firm's prices to retail consumers would not increase because of inflated prices paid to an affiliate supplier. Under one scenario, regulators could set maximum allowable retail prices in core markets based on cost indices for a group of regional utilities.

[94] True independent power producers are defined as those power generators who own no transmission facilities, have no affiliation with vertically integrated utilities, or have no retail franchises.

[95] Bernard W. Tenenbaum and J. Stephen Henderson, "Market-Based Pricing of Wholesale Electric Services," *The Electricity Journal* 4, no. 10 (December 1991): 30-45.

access on a nondiscriminatory basis. Consequently, they should reduce the uncertainty faced by both project leaders and suppliers over future revenue streams. It is anticipated that, with promulgation of the new rules, the price of wholesale power will be driven by market forces. Wholesale producers, therefore, will likely enjoy opportunities to profit from innovations in a way similar to that of unregulated firms.

On the other side, under a market-oriented environment, producers will be less protected by regulation from some of the risks associated with innovation. A review of recent sales contracts between independent power generators and utilities shows that most of the construction and operation risks fall on generators.[96] Thus, while IPP producers will likely not face "used and useful" disallowances, because their power will be sold by contract rather than governed by ratebase regulation, there will be no tolerance by the marketplace of underperformance, either in construction or operation. These contracts may in part reflect the perception of state commissions that power purchases are likely to be only beneficial to consumers when producers assume most of the risks.

The amendments to PUHCA should contribute to the future development of IGTs for several reasons:

1. More new generation will fall outside the purview of rate-of-return regulation. Power generators will have a greater opportunity to profit from successful performances of new technologies under a market-based pricing environment. For example, spinning off an existing rate-based facility may result in a utility repowering the facility with an innovative technology. The economic performance of generators will depend largely on the successes of generators to control construction costs and to operate at high levels of efficiency. The payoff for successful experiences will likely exceed that under rate-of-return regulation and be compatible to that earned under an unregulated environment.

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[96] Edward P. Kahn, "Risks in Independent Power Contracts: An Empirical Study," *The Electricity Journal*, 4 no. 9 (November 1991): 30-45.

2. More new generation will come from non-PURPA qualifying facilities. The size, ownership, fuel use, and technology constraints of PURPA have diverted entrepreneurial activities from the development of potentially more economical generating technologies.[97] Some of the emerging new technologies cannot be deployed economically at generating facilities satisfying the requirements of a PURPA-qualifying facility. New technologies exhibiting economies of scale, especially, may be helped by the new PUHCA legislation. Some analysts believe that lifting restrictions on wholesale power production will have the largest effect on the use of natural gas by nonutility facilities.[98]

3. The amendments to PUHCA, along with easier transmission access stimulated by recent amendments to the FPA, may change the nature of, in addition to expand, the market for wholesale power. With opportunities to sell to more buyers wholesale producers may not be restricted to signing long-term sales contracts. The potential for opportunistic behavior by vertically integrated utilities has prevented the formation of a spot or short-term contract market for power and thereby has necessitated long-term contracts. A spot market may develop over time that would increase the competitiveness of wholesale power markets, with producers having additional incentives for innovation. It is also expected that a more diverse output (power) market breeds a more diverse input market, where there would be more variety of power technologies. For example, growth in peak-load and standby capacity may be stimulated in a market that is not limited to long-term contractual transactions. Finally, easier transmission access would make larger generating facilities more attractive as market opportunities increase: the potential benefits of economies of scale increase anytime the seller has a larger market to which it can sell. Consequently, new

[97] This was one of the major arguments used by PUHCA-reform advocates.

[98] The extent to which these facilities will provide base-load power depends on the cost of natural gas relative to competing fuels.

technologies exploiting economies of scale may be disproportionally helped by the liberalizing of transmission facilities.

4. New competition stimulated by the amendments to PUHCA and easier transmission access, together, may accelerate the replacement of rate-of-return regulation with looser regulation or, in some cases, deregulation. As a general rule, traditional regulation works best when firms offer bundled services, have limited supply options, and when technology is unchanged. Continuing with current regulatory procedures in a more competitive environment may produce large efficiency losses that are costly to both regulated firms and consumers. Unless regulators can accommodate the new changes on their own, outside pressure by special interests, and "inside pressure" by consumer groups such as large industrials, will likely prevail. These groups see a new regime as being responsive to their economic well-being. When this occurs, regulators may be forced to change their *modus operandi*. Experiences in other industries where competition proliferated have shown that tight regulation is replaced by either incentive-based regulation or deregulation. In each case, firms would likely face a more favorable environment for innovation and other entrepreneurial activities.

Concluding Remark

The foregoing review leads to certain conclusions regarding the effect of regulatory practices on the adoption of IGTs. In general, current state price regulation at most provides weak incentives for innovation. Most of the current regulatory practices are designed to protect ratepayers from the effect of poor decisionmaking and management. While such practices penalize poor performance, they provide little or no explicit reward for good performance. This discourages risk-taking and innovation.

It should be emphasized that both the success of the competitive thrust of the CAAA and the EPAct, and the realization of resulting benefits depend critically on the facilitating role of regulators. Finally, while the increase in competition may reduce the need for close regulatory oversight, it may pave the way for new regulatory ratemaking procedures.

Regulators need to pursue policies that promote the adoption of IGTs with superior energy efficiencies and environmental performance while protecting the ratepayers' interests enhanced by cost minimization and reliability. The twin vehicles of incentive systems and procompetitive policies can be used to achieve these goals.

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CHAPTER 5

POWER PROCUREMENT SOLICITATION AND INNOVATIVE GENERATION TECHNOLOGIES

Defining Uneconomic Barriers

All restrictions on the development of a specific technology are barriers of some sort but not all of them qualify as uneconomic barriers. An uneconomic barrier is defined here as any restriction (unintentionally or intentionally) lowering the long-term economic interest of electricity consumers. In the context of this report, an uneconomic barrier can exist whenever the net benefits of innovative generation technologies (IGTs) are undervalued, from the perspective of consumers, either by vertically-integrated electric utilities or nonutility generators (NUGs). This definition draws upon consumer sovereignty, a foundational concept underlying welfare economics and regulation. Consumer sovereignty implies the market process will optimally allocate resources when guided by the preferences of ultimate consumers. Producers are subordinate, as their primary task is to produce efficiently and respond favorably to consumer preferences. Consumer sovereignty imbues a natural hierarchy upon the market process, one emphasizing the primacy and welfare of consumers, which underlies the concepts of equity and efficiency as used in economics.

The competitive market process, although inherently discriminatory and restrictive, achieves the best results when unfettered. Consumers must select the combination of goods and services in their best interest while staying within a budget restraint. The consumer's right to be selective, although detrimental to some producers, is not considered an uneconomic barrier. Instead, it is deemed an important and inevitable characteristic of consumer sovereignty and the welfare maximization process. It improves economic efficiency by removing inefficient producers or those producing unwanted goods and services. The presence of consumer sovereignty and unfettered markets are fundamental to obtaining a social optimum even though some producers will inevitably suffer in consequence.

Sometimes restrictive practices are uneconomic barriers. For example, incumbent firms using restrictive practices to impede market entry constitute an uneconomic barrier. But the adverse consequences upon potential entrants does not, in itself, constitute evidence of an uneconomic barrier. Rather, entry restrictions are uneconomic barriers only when they impede the flow of alternative goods and services potentially beneficial to consumers. They further weaken competitive forces capable of lowering market prices and raising consumer surplus.[1] The crucial determinant is whether the restrictive practice tends to raise or lower consumer welfare. Whenever it lowers consumer welfare restrictive practices can be construed as an uneconomic barrier.

Monopolies are another common source of uneconomic barriers. But barriers do not occur merely because the market has a sole supplier; they instead occur when market supply is restricted to artificially raise price and profit. It can be argued that the barriers are created by the social welfare loss from allocative inefficiency. However, if this were true then a market with a perfectly price discriminating monopolist would be an appropriate market structure. In fact, perfect price discrimination would be held equivalent to perfect competition in the sense that both market structures are allocatively efficient. But there is an important difference: a perfectly competitive market maximizes consumer surplus whereas the opposite occurs under perfect price discrimination. Perfect competition restricts the activities of suppliers by eliminating those less efficient. By contrast, perfect price discrimination places restrictions upon consumers by erecting barriers to purposely impede resale markets. This enables the monopolist to behave opportunistically, set prices equal to an individual's willingness to pay, and leave consumers only marginally better off.

[1] Economists apply the term consumer surplus to measure the net benefits realized by consumers when they purchase goods and services (that is, the difference between the value consumers receive from purchases and the cost they must incur). An allocatively efficient system (either a perfectly discriminating monopolist or a perfectly competitive market) maximizes the total of consumer and producer surplus. But only a perfectly competitive market maximizes consumer surplus.

The capability of utilities to expropriate consumer surplus through monopolistic practices, including establishing barriers to entry by potential suppliers, underscores the rationale for regulation. In part, state commissions attempt to mimic the benefits from consumer sovereignty by restricting a utility's pricing, service, power procurement, and investment decisions. The restrictions sanction certain practices while prohibiting others. As long as the eventual outcomes are in the public interest, certain restrictions become defensible. But when consumer welfare is adversely affected, then the restrictions according to our definition become uneconomic barriers.

A recent study conducted for the National Association of Regulatory Utility Commissioners (NARUC) included the effects of state regulatory practices and policies on the development of renewable energy.[2] It identifies several actions directed at accelerating the penetration of renewable energy in the electric power industry (see Table 5-1).

While each of the specified actions with little doubt would assist renewable technologies, many of which could be regarded as "innovative," it is another matter to say that they would necessarily be in the long-term interest of consumers. In other words, the proposed actions may go beyond compensating for or eliminating uneconomic barriers.

This chapter makes no attempt to separate out those obstacles to new technologies regarded as barriers in the economic sense and those that are not. As in the case of demand-side management (DSM), what one defines as an obstacle that diminishes the public interest is in the eye of the beholder. For example, proponents of utility-financed DSM programs have argued that a major barrier to the promotion of energy conservation by electric utilities is traditional regulation: a utility realizes short-term profit losses with lower electricity sales. They have supported the adoption of revenue decoupling mechanisms to eliminate this obstacle. Some opponents and skeptics

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[2] Dr. Jan Hamrin and Nancy Rader, *Investing in the Future: A Regulator's Guide to Renewables* (Washington, D.C.: National Association of Regulatory Utility Commissioners, February 1993).

TABLE 5-1

REGULATORY PRACTICES FAVORING RENEWABLE TECHNOLOGIES

- The inclusion of "diversity" and new technology-demonstration benefits into integrated resource planning
- Flexible power procurement mechanism (price representing only one of several factors)
- Innovative financing
- Green pricing and requests for proposals
- Utility incentives for purchasing renewables
- Accounting of nonmarket benefits
- Accurate measurement of benefits of renewables
- Standard power contracts
- Front-end-loaded contracts
- Up-front regulatory guidelines ("safe harbor" rules) on ratemaking treatment of new technologies

of DSM programs have argued, on the other hand, that profit losses do not reflect a real uneconomic barrier; rather they reflect the fact that utility prices are simply too high, thereby inducing excessive energy conservation.

Some analysts and regulators may argue that some of the regulatory actions favorable to renewable technologies would hurt consumers. For example, paying front-end-loaded prices may result in consumer higher prices in the near term that, in present value terms, are not compensated for by lower prices in later years. The owner of the renewable facility may be getting an extremely attractive implicit load rate that in effect is being funded by consumers.

These same qualitative arguments could be applied to incentives for any new technologies. The important analytical issue is to define which barriers are "uneconomic," and to tailor remedies that address these barriers.

Relationship of NUGs to Other Market Participants

Different factors affect nonutility generation (see Figure 5-1). First, NUGs require funding from capital markets. Lenders look at a wide array of regulatory, economic, and operating factors associated with a purchased power contract. These factors include the cost of power, payment of energy and capacity charges, regulatory policies on cost passthrough, and the competence of the managing party.[3] Without the availability of funds or funds at acceptable interest rates, NUGs would not exist.

Second, the willingness of a utility (currently, and for the foreseeable future, the major buyers of power from NUGs) to enter into a contract with certain NUGs depends on several factors. A major one is the selection process used to identify "winning" NUGs. If the process does not include NUGs, but only PURPA-qualifying facilities, then of course NUGs would have less opportunities to sell power. If NUGs are included, then their likelihood of being selected hinges on a host of factors that are weighed explicitly or implicitly to arrive at a decision.[4]

The utility's decision relating to how much power to purchase from NUGs and from whom depends to a large extent on the state commission's practices and policies. Particularly through its "planning-procurement-contracting" oversight and ratemaking

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[3] See, for example, Laura J. Rittenhouse, "Perceptual Survey of the S&P Purchased Power Credit Risk Policy," *The Electricity Journal* (April 1992): 42-52, and John Simpson, "Conference Examines Purchased Power Topics," *Public Utilities Fortnightly* (December 15, 1992): 30.

[4] See Kenneth Rose, Robert E. Burns, and Mark Eifert, *Implementing a Competitive Bidding Program for Electric Power Supply* (Columbus, OH: The National Regulatory Research Institute, 1991).

Fig. 5-1. Factors of nonutility generation (Source: Authors' construct).

activities, (for example, the cost recovery of purchased power), a commission can affect the willingness and ability of a utility to purchase power from NUGs.[5]

Basic Regulatory Rules

Regulatory rules should at the minimum include two components that affect the potential use of IGTs by NUGs. First, they should specify up front the allocation of risks between utility shareholders and consumers. At one extreme, a commission could allow for preapproval of contracts between NUGs and utilities. Such a regulatory treatment would certainly be favorable for purchased power contracts. This action would eliminate, for example, the risk of a utility exercising a "regulatory-clause" response, and thereby lower the risk to NUGs, including those deploying IGTs.

A commission could also, as is the typical practice of state commissions, approve of purchased power contracts but retain the right to review their prudence after-the-fact. Retrospective reviews could dampen the willingness of lenders to fund NUG projects if a contract contains a regulatory-out clause. Such a clause, however, may be required by a utility before it would commit itself to buying power from a NUG, in particular one that deploys an innovative technology.

In practice, if utilities apply a commission-approved bidding/project selection mechanism, and then bring their slate of winning bidders to the commission, retrospective disapproval rarely occurs. This is because underperformance would be punished by the terms of the contract.

Second, regulatory rules should specify the incentives that are provided to utilities to purchase power. In practice, it is rare for commissions to authorize explicit incentives

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[5] See Paul L. Joskow, "Expanding Competitive Opportunities in Electricity Generation," *Regulation* (Winter 1991): 25-37.

for purchased power.[6] Utilities generally receive dollar-for-dollar passthrough of purchased power costs. Some analysts have argued that giving utilities an opportunity to profit from power purchases that reduce their cost of service would greatly enhance their interest in power purchases. Experiences with DSM incentives have shown that utilities respond quite actively to incentives that allow them to earn profits from activities that are deemed to be economical. Incentives for purchased power could elicit a similar response from utilities.

Table 5-2 lists four major actions that regulators can take to promote the deployment of IGTs by nonutilities. By minimizing regulatory uncertainty, by allowing pricing flexibility,[7] and by generally promoting the entry of NUGs, regulators can play an important role in accelerating IGTs.

TABLE 5-2

REGULATORY PRACTICES/POLICIES STIMULATING IGTs

- Explicit regulatory incentives for purchased power
- Clear, up-front regulatory guidelines
- Pricing flexibility for new generating facilities
- Targeted actions promoting growth of nonutility generation sector (for example, set-aside program for renewables)

[6] See RCG/Hagler Bailly, Inc., *Comments on Incentives for Purchases of Non-Utility Generated Power in the Proceeding to Consider the Reauthorization of the Texas Public Utility Commission*, prepared for the Sunset Review Commission of Texas, June 1992.

[7] Pricing flexibility is a matter for the Federal Energy Regulatory Commission, which has sole jurisdiction over the pricing of wholesale power.

Views on New Technologies

A study on renewable technologies conducted for NARUC presents a rationale for why more intensive commitment (for example, favorable purchased power solicitation rules), can be warranted for accelerating the commercialization of new generation technologies that are currently uneconomical or are at the precommercial stage.[8] First, demonstration of these technologies can generate valuable information, learning benefits, and potential environmental benefits. Second, demonstration of a new technology on a small scale can avoid potentially large negative outcomes in the future; this could occur, for example, if the technology is instead quickly adopted on a large scale. The experiences with nuclear power suggest that a demonstration stage could have avoided the significant problems that transpired later.[9] A broad-based argument in support of demonstration/pilot programs is that limited investments today can help to insure against potentially large risks in the future. Third, utilities can reduce the risks associated with an uncertain future by diversifying their investment portfolios. This may include making investments in certain technologies including renewables, energy conservation, and conventional generation technologies.

A 1991 NRRI report, *Implementing a Competitive Bidding Program for Electric Power Supply*, includes the responses to a survey. The survey was sent to all state public utility commissions, including the District of Columbia, and to most investor-owned electric utilities. Forty-nine state commissions and eighty-six utilities from forty-six states responded to the survey by March 1, 1990. The responses, among other things, provided information on the views of commissions and utilities regarding different generation technologies owned by nonutility producers. First, 45 percent of the state commissions felt that technology maturity was an important factor in project evaluation; 58 percent of the electric utilities felt the same.

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[8] Hamrin and Rader, *Investing in the Future*.

[9] It should be noted that several nuclear power plants around the country have exemplary records. The main reason appears to be that the owners of these facilities were intimately involved with the design and they realized that nuclear facilities were fundamentally different from other steam plants.

Second, many respondents felt that the likelihood of a project completing construction, or technical feasibility, was an important factor in the evaluation process. Respondents expressed that the history of similar facilities was a major determinant of technical feasibility. Overall, the responses suggest that new technologies should be "penalized" in evaluating power procurement proposals.

An earlier NRRI report on competitive bidding echoes a similar view:

> It is best to separate the assessment of technical feasibility from other considerations in a bid evaluation. Bids with low technical feasibility either should be excluded from bidding or be treated in a separate solicitation with different financial arrangements to assure that the project sponsor assumes a large portion of the financial responsibility in case of technical failure (at 127).[10]

The NRRI report identifies two basic approaches for the consideration of price and nonprice factors in a bid solicitation. Each approach in a different way attempts to assess these factors in terms of their individual effects on the host utility. The first approach evaluates bids solely on the bid price, while nonprice factors are regarded as a binding constraint; it considers nonprice factors on a subjective basis, for example, by incorporating a commission's policy preference in the evaluation process that may reflect social benefits external to the market transaction. The second approach involves a merit selection system, or what is sometimes called a scoring method, whereby different weights are assigned to various prespecified price and nonprice factors.

Basic Features of Power Procurement Contracts

The wholesale power agreement becomes the incentive contract binding together utilities and NUGs. For the most part, utilities seldom have complete information to

[10] Daniel J. Duann et al., *Competitive Bidding for Electric Generating Capacity: Application and Implementation* (Columbus, OH: The National Regulatory Research Institute, 1988).

scrutinize a NUG's activities and consequently must rely upon outcome-based compensation schemes. A common practice is to base compensation upon how well a NUG's performance compares to well-defined, prespecified performance targets or standards. Agreement of this type contain both "linear" and "threshold" characteristics: linear contracts are of the form, $\mathbf{c = a + bq}$, where **c** denotes compensation, **a** and **b** negotiated parameters, and **q** denotes output; most contracts modify the basic linear contract with performance thresholds to affect the parameters' values. For example, the NUG may be compensated according to the formula above as long as **q** is above some minimum level. Otherwise, the value of **a** or **b** may be downgraded thereby reducing compensation.

Modified linear contracts are incentive compatible[11] as long as outcomes are largely unaffected by uncertainties. They therefore tend to benefit conventional technologies more so than newer ones since newer technologies are inherently more risky. Strict adherence to performance standards will unlikely guarantee a dependable revenue flow to finance learning and development costs. This tends to diminish the flow of resources toward the development of new technologies by persuading profit-seeking developers to pursue known technologies with lower levels of internal risk.

In addition to compensation schemes, most power procurement contracts involve vertical restrictions to fully define the relationship and insure incentive compatibility among parties. Vertical restrictions can run in both directions and usually manifest themselves as contractual stipulations specifying how and when to modify the compensation scheme and to what extent the parties are contractually liable. Minimum and maximum-take clauses, regulatory-out and force majeure clauses, are but some of the ones commonly used by NUGs and utilities in the wholesale power market.

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[11] In the context of this chapter, incentive compatibility means that the NUG serves the interest of the utility when it serves its own interests.

Minimum-Take Clause/Take-or-Pay Clause

The minimum-take clause guarantees the NUG a minimum amount of revenue, assuming it can supply the power. This can be extremely important to a NUG's ability to acquire capital to finance projects and frequently will be in the form of a take-or-pay or take-and-pay clause within the purchase power contract.

Maximum-Take Clause/Take-and-Pay Clause

The maximum-take clause limits the NUG's obligation to the utility, which has important implications. First, it limits the obligation to supply capacity on an as-needed-basis, and in so doing, bounds the utility's usage of a take-and-pay clause. The take-and-pay clause protects the utility from adverse selection, that is, from contracting with inefficient NUGs. For example, it allows the utility to downgrade a NUG's capacity rating and thereby avoid making full payment for power amounts supplied.

The maximum-take clause limits the utility's use of take-and-pay clauses and offers some protection from opportunistic behavior. Second, it allows the NUG time to make repairs and overcome forced outages while protecting its system integrity and financial viability. Overall, minimum and maximum-take clauses protect NUGs by restricting the flexibility of the utility. At first glance, NUGs utilizing newer technologies would seemingly benefit most from such clauses since their performance is more suspect and prone toward discontinuity. But this fails to hold when power is secured through a utility solicitation since both clauses are set by competitive forces. Consequently, conventional technologies fare better because owners or operators can generally better afford to accept lower minimum takes and higher maximum takes.

Regulatory-Out Clause

The regulatory-out clause allocates exogenous risk caused by regulatory disallowances or policy changes. In its extreme form, all risks are shouldered by the

NUG, providing the utility with full insurance against regulatory uncertainty. Insurance is not a costless good, however, and is typically paid for with higher prices for NUG power supplies. For example, the NUGs raise prices to cover additional financing expenses; but this practice tends to mostly burden projects offering longer-term power supplies. This is not surprising given the fact that the costs of regulatory uncertainty rise with time.

Force Majeure Clause

The force majeure clause is likewise intended to allocate exogenous risks among parties in ways deemed reasonable. It offers temporary relief from contractual responsibility when one party is unable to fulfill its obligation for reasons outside its control. In other words, force majeure clauses typically do not protect NUGs from endogenous risks, for example owing to equipment failure or fuel supply interruptions. Consequently, they offer little protection for newer technologies whose endogenous risks are relatively greater.

Other Risk-Shifting Practices

Many other practices are commonly employed to shift risks disproportionately toward NUGs. Most purchase power contracts routinely require security deposits to insure utilities against costly construction delays and performance bonds to protect against a project's inability to meet minimal performance standards. Project developers frequently respond by shifting the preponderance of risks toward the project's contractors through turnkey contracts. Turnkey projects usually require the contractor to accept fixed-price agreements with date-specific on-line dates. The developer does not assume responsibility until after the facility has successfully passed specific performance-based tests.[12] The eventual consequence is to concentrate risk in a way limiting the absolute

[12] E. P. Kahn et al., *Analysis of Debt Leveraging in Private Power Projects*, prepared for the U.S. Department of Energy under contract number DE-AC03-76SF00098 (Berkeley, CA: Lawrence Berkeley Laboratory, August 1992).

amount of risk sharing possible. One benefit of turnkey projects is that they give the contractor strong incentives to hold down costs. Naturally, project contractors will tend to avoid innovative technologies (unless, of course, they are also vendors of the technologies) and favor conventional ones simply because they are less risky and more easily financed.

Utility Power Purchase Solicitations and Risk Allocation

One primary purpose of power purchases should be to efficiently allocate risk and return. One interesting feature of most power procurement agreements, especially those secured through a competitive solicitation, is the one-sided allocation of plant-operation and plant-construction risks (see Table 5-3): predominately all of these risks, both exogenous and endogenous, are assumed by NUGs; this tends to induce a favoritism for conventional technologies.

A reasonable concern is whether or not the current set of vertical restrictions allocating risks toward NUGs is optimal from the viewpoint of the general public. If so, then the current allocation implies that the general public must be highly risk averse toward NUGs in particular and competitively secured supplies in general. Most contracts put the risks owing to project development, construction, and completion as well as most financial risk from changing regulations, tax policies, environmental standards, and changing fuel prices (where risk is shared with the utility) upon the NUG.[13] This tendency is efficient as long as welfare maximization requires minimizing the public's risk position. Should the contrary hold, however, then restrictions allocating most of the risks away from the general public and toward NUGs is inefficient and constitute uneconomic barriers. Their origin and possible distorting effects upon power markets and a utility's choice over competing technologies would then become important economic issues.

[13] Mason Willrich and Walter L. Cambell, "Risk Allocation in Independent Power Supply Contracts," *The Electricity Journal* (March 1992).

TABLE 5-3

TYPICAL RISK-ALLOCATION FEATURES OF PURCHASED POWER CONTRACTS BETWEEN NUGs AND UTILITIES

- Fuel cost indexing (allocates fuel-price risk between utility and NUG)
- Demand-risk borne by utility
- Plant-operation risk borne by NUG
- Plant-construction risk borne by NUG

The consequences of monopsony power of, and risk avoidance by, utilities upon the adoption rates of innovative technologies strongly affects future levels of research and development. The utility's monopsony position in a power procurement solicitation enables it to pay the minimum premium necessary to insure against various forms of risks, especially those of endogenous origin. This forces development of riskier technologies to overcome their insurance cost disadvantages with performance advantages that the technologies may possess. Initially, this may seem in the public's interest and perhaps so in a static world of fixed technologies and highly reliable and available information. When supply efficiencies depend upon technological innovation as a primary source, however, the combination of high risk aversion and monopsony power may unduly penalize newer technologies and inefficiently lower adoption rates. Newer technologies are plagued by an insufficient history to allow an accurate assessment of their risk: rather than a single distribution of potential outcomes defining the risk characteristic of the technology, newer technologies usually involve a family of distributions;[14] in other words, they involve a distribution of potential distributions. A highly risk-averse utility would tend to assume a worst case scenario when scoring projects utilizing more innovative designs. Naturally, this lowers adoption rates of innovative technologies by inducing a preference for more conventional technologies whose outcomes are more predictable and reliable.

Front Loading of Payments

Front loading occurs when a NUG requires a stream of payments above the utility's avoided costs during the project's earlier years of service. The amount front loaded is considered an implicit loan by the utility, who usually chooses an interest rate above its own discount rate to assess its cost. Commonly, a project's value (score) is revised downward to reflect the loan's cost. This practice mostly penalizes larger, capital-intensive projects, some of which may deploy newer technologies that require a ready source of funds to cover initial development costs. The developers are further penalized should the project's perceived risk, from the standpoint of the utility, underscore the loan's implicit interest rate:[15] a higher loan rate results in a larger downward revision to a project's score artificially making it appear less economical. This bias can even cause innovative projects requiring a smaller amount of front loading to

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[14] Preliminary feedback from newer technologies is typically ambiguous. The information tends to form clusters signifying a multimodal distribution process. Consequently, a family of unimodal distributions, one per information cluster, may characterize newer technologies. A highly risk averse utility desiring maximum insurance would choose among the least favorable information clusters to assess the technologies risk.

[15] Based on a selected survey, implicit loan rates can vary substantially across utilities scoring systems as well as within a particular scoring system. In one utility scoring system, the implicit loan rate was as high as 96 percent. For more information see, Steven Soft and Edward Kahn, "Evaluation of Front Loading in Auctions for Wholesale Power," *Utilities Policies* 1 (October 1990): 28.

seemingly appear more expensive compared to conventional technologies of similar or smaller size.

Front loading does indeed favor smaller, conventional, fuel-intensive projects. This should not necessarily imply, however, the presence of an uneconomic barrier. This distinction depends on whether the final generation mix offers the optimal mix of characteristics from the perspective of the general public or consumers as a group. Suppose, for example, the utility levies a 12 percent interest rate on amounts front loaded by conventional technologies but a 24 percent rate for IGTs. By implication, utilities would perceive IGTs to be double the risk further implying they must offer double the savings to remain competitive.[16] Failing to achieve these savings, IGTs would receive lower scores with few if any receiving wholesale power contracts. The award group would most likely consist solely of conventional projects. This becomes problematic when consumers may have preferred larger, capital-intensive projects embodying newer technologies.[17]

It is easy to suggest that the utility or state commission is directly responsible for the uneconomic barrier. This, though, would be presumptuous: the primary source in this case may not be the utility nor the state commission, even though it may have purposely misinformed the utility concerning the general public. The incentives facing the state commission are likely to be the source of the problem: the possibility of high political costs may have induced conservatism and risk aversion by the state commission; in so doing, it can deter the promotion and adoption of innovative technologies.

On the other hand, this very same front loading practice, although discriminatory and restrictive, becomes efficient should the public want to avoid newer technologies

[16] This is a hypothetical example presented for illustrative purposes only.

[17] A preference for innovative technologies implies a forward-looking social agenda. Fostering innovative generation turns into an investment strategy benefitting future generations and is rational as long as the social discount rate on consumer surplus is low.

owing to their perceived riskiness. In this case, doubling the discount rate properly signals project developers about the public's aversion toward them.[18] Clearer messages could help developers submit project proposals both in their interest and the public interest. In so doing, it in turn could better streamline the power procurement solicitation process by reducing transaction costs. It could further motivate stronger competition by causing some developers to switch from innovative projects toward more conventional ones.

A state commission bent on dissuading particular technologies has the power to apply overt strategies. For example, it could purposely and selectively complicate the siting, certification, and permitting processes legally required to sell power in ways that allocate exogenous risks disproportionately.[19] Or they could bias the selection process by simply holding the utility's investors responsible for a project's nonperformance. The policy might allow only the contract's original purchase price to be borne by ratepayers. All additional costs would be assumed by the utility. This strategy undoubtedly creates a bias favoring smaller projects utilizing conventional technologies.[20] Furthermore, a state commission could favor certain technologies by its treatment of pollution allowances. A commission, for example, could allow utilities to earn profits on pollution

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[18] To be symmetrical, public preference for innovation would lower the appropriate discount rate for particular new technologies.

[19] It is quite common for the risks and costs associated with licensing, siting, and permitting to be borne by project developers. For more information see: National Independent Power Producers, *Negotiating Risk: Efficiency and Risk Sharing in Electric Power Markets* (Washington, D.C.: National Independent Power Producers, September 1992). Utilities could likewise pursue a strategy to disproportionately raise the cost of entering a solicitation. For example, it could impose costly information requirements in ways that mostly penalize undesired technologies.

[20] The utility would prefer a portfolio of smaller projects since this would minimize its risk position for a given capacity level than would a portfolio consisting of a few large projects. As mentioned earlier, insurance is not free implying the average purchase price will be higher in consequence.

allowances sold as part of a wholesale power purchase but deny them otherwise. Naturally, newer and cleaner technologies are disadvantaged by such a policy.

Wholesale and Retail Contracts

The relationship between a state commission and utility is both complex and multifaceted. One primary source of complexity stems from the distinctive treatment of retail and wholesale power transactions, the consequences perhaps manifested mostly in competitive solicitations. Specifically, state commissions in effect allow utilities to earn a profit on power they buy from themselves but not on power bought from others.[21] Consequently, there are two distinct and competing incentive contracts affecting utility decisions on whether to build or buy.

A utility is more accepting of risk under the build option because it has the opportunity to earn a compensatory rate of return (assuming minimal risks from retrospective reviews). This is made possible because of the implicit incentive contract governing retail power that rewards utilities for assuming and managing risk. The buy

[21] Some analysts argue that utilities are not compensated for the risks they bear in purchasing power. They contend that utilities face nonzero risk, since there exists the possibility of cost disallowance by their regulators and purchased power is regarded as equivalent to debt by the financial community, but they receive no explicit profits. In the vast majority of states, purchased power is treated as an expense that can be recovered either in base rates or a fuel adjustment mechanism. It can also be argued that compensation in the form of incentives rewards a utility for intelligent purchasing decisions that lower costs and shift risks and place power purchases on a more equal basis with utility-owned generation and demand-side activities.

On the other hand, buying power from NUGs may be less risky to utilities because of the avoidance of construction risks, the reduction of regulatory risk, and the diversification of the utility's power portfolio. For example, the utility can expect higher assurance of recovering its costs for purchased power than for new internal construction. It is expected, however, that state regulators will review purchased power contracts more closely in the future as the amount of purchased power grows.

option for most electric utilities, on the other hand, offers no offsetting compensation nor reward for assuming risk and encourages risk avoidance in decisionmaking.[22] Essentially, the state commission is signalling the utility to minimize all forms of risk as a buyer in wholesale power markets. By conditionality, the incentive contracts between utilities and NUGs should reflect this preference, which is unbalanced and emphasizes penalties. And indeed, this is the case.

The NUGs are commonly compensated according to how well they compare to competitively determined performance standards. Below-average performance invokes penalties usually assessed on capacity payments.[23] Naturally, capital-intensive technologies suffer most because of their heavy reliance upon capacity payments as the primary revenue source. Capital-intensive projects are more likely to supply base load or intermediate power, making their reliability of utmost importance. Their inability to perform can become costly should the utility be forced to pursue more expensive replacement power. Consequently, utilities will likely avoid capital-intensive NUG projects since they are unable to earn a compensatory return needed to justify the additional risk to investors. Innovative technologies suffer even more so since performance standards are determined by competitive forces, which favor conventional technologies. In short, it is argued here that utilities are unlikely to purchase large amounts of base-load or intermediate power from a particular NUG, especially ones utilizing innovative and unproven technologies. The disparity in incentive contracts tends to encourage a utility to build a conventional facility when large amounts of capacity are needed.

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[22] Utilities relying heavily on purchased power produced by NUGs, in fact, have seen their bond ratings downgraded as these transactions are viewed by the financial community as debt obligations. Power purchases affect a utility's credit and financial obligations, even though external financing is not involved.

The risk to the utility from purchasing power generated by an innovative generation technology stems from several factors: unreliable power, uncertainty of passthrough costs, the possibility of nonperformance, and the cost of renegotiating contract provisions in response to adverse outcomes.

[23] This is especially true when contracts contain what is known as a "take and pay" provision.

Concluding Remarks

An important conclusion of this report is that a robust nonutility generation sector could be the most important determinant of the commercialization of IGTs. Several observations of the association between utility and regulatory practices/policies and the selection of certain technologies by NUGs can be made:

1. Fuel diversity is a nonprice factor that, if taken into account in the power-procurement solicitation process, would in many cases favor new capital-intensive technologies.
2. Regulators can define a "level playing field" as a condition whereby the NUG chooses a technology that yields the highest benefits both to itself and to society at large.
3. The accumulated effect of regulatory actions on technology selection by a NUG is composed of different elements. (See, for example, in Table 5-1 the several factors favoring renewable technologies that, in one way or another, are influenced directly or indirectly by regulatory action.)
4. Although environmental adders increase the attractiveness of environmentally benign technologies, they also make DSM activities more economical.
5. The acceptance of the revenue-requirements or discounted cash flow (DCF) method in the context of integrated resource planning would tend to depreciate the value of capital-intensive and low fuel-using technologies and new technologies in general.[24] DCF, for example, has had a poor track record in selecting promising new technologies. Some analysts have argued that new technologies should be evaluated on the basis of the cost incurrence on an electric power system relative to the risk effect. In other words, a utility should not select new projects (either

[24] See, for example, Shimon Awerbuch, "Measuring the Costs of Photovoltaics in an IRP Framework," presented at the Fourth National Conference on Integrated Resource Planning, Burlington, Vermont, September 16, 1992.

internal or external ones), especially those incorporating innovative technologies, on the basis of their revenue requirements (or price) but on their risk-return relationship. The revenue-requirement method, although appropriate under certain conditions, may be ill-suited for evaluating different technologies with varying degrees of risk.[25]

6. "Regulatory out" clauses, by placing additional risks on NUGs, can severely dampen the prospects of new technologies.
7. An almost exclusive emphasis on price for power procurement would tend to hurt those new technologies that have relatively large environmental and other benefits not reflected in the price variable. Also, as argued by some independent power producers, too much emphasis on price may drive profit margins down to discourage technological innovations as a whole.
8. Regulatory actions such as approval of "regulatory out" clauses in power procurement contracts can place pressure on NUGs to shift the risks of new technologies back to vendors in the form of turnkey projects. Vendors may be willing to assume these risks in return for information and other benefits that could profit them in the future.
9. An overemphasis on price in assessing candidate projects during a power procurement solicitation could make other supply characteristics, such as environmental consequences, subordinate in the selection process. This could especially hurt those innovation technologies that are extremely environmentally benign but not currently cost competitive with other technologies (for example, certain renewable technologies). Commissions can account for the nonprice attribution of a technology in a competitive power procurement in one of two general ways: utilities can be required to purchase at least a minimum amount of power produced by the technology (for example, "Green Request for Proposals") or to adjust downward the cost associated with the technology. The first option

[25] Ibid.

would guarantee a market for new technologies, while the second attempts to put new technologies on a more "level playing field" but with no assurance of a market.

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CHAPTER 6

DIFFERENT REGULATORY INCENTIVES FOR IGTs: RATIONALE AND ASSESSMENT OF OPTIONS

A major conclusion reached earlier in this report is that explicit regulatory incentives may be needed to compensate a risk averse utility to adopt new technologies that have the lowest expected cost. As history in the electric power industry has demonstrated, regulated utilities will tolerate downside risk as long as they have the opportunity for compensatory profit on the upside.[1] Consequently, a regulatory ceiling on upside profits can act as an economic barrier to utility investments in innovative generation technologies (IGTs). Specifically, rate-of-return (ROR) regulation as currently practiced provides an electric utility with weak incentives for innovation by imposing high risks on utilities relative to opportunities for upside profits.

The inherent problems of ROR regulations are two-fold: firms have better information than regulators about the marketplace and how to achieve high efficiency; and the goals and preferences of firms are likely to differ from those of society at large.[2] Although regulatory lag provides some incentive, it is weak with regard to eliciting more innovative activities by utilities, especially those with a long payback period. Regulatory lag also has the problem from a commission's perspective, of obstructing the reallocation of the resultant benefits to consumers.[3] In any event regulators, in accelerating the development of IGT, should consider offering utilities stronger incentives than what they currently have under ROR regulations.

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[1] See, for example, the discussion in Chapter 4.

[2] Sanford V. Berg et al., *The Potential for Using Performance Indices To Provide Regulatory Incentives*, Final Report to the New York Public Service Commission, December 30, 1992.

[3] For example, the stronger regulatory lag is, the larger the utility share of the aggregated economic gains from improved productivity or successful innovations.

The shortcomings of ROR regulations become more evident when regulated firms operate in markets where some customers have choice of suppliers. In such a partially-competitive environment, a firm would need more flexibility in pricing different services and more opportunities to earn higher profits in view of the higher risks that it faces.[4] Regulators, at the same time, should be most concerned about possible price discrimination that hurts certain customers and cross-subsidization that also hurts certain customers as well as new entrants.[5] ROR regulation is most effective when firms have broad monopoly power; it tends to create problems, however, when competition starts to penetrate a highly monopolistic industry.

The argument for modifying ROR regulations in a partially competitive environment suggests that a new comprehensive ratemaking system may be warranted. Such a system would have two general characteristics. One, it would allow firms more flexibility in pricing their services in markets where they confront competitors. Second, firms would be less constrained by the profits they can earn, both on the downside and upside. Firms would therefore have monetary incentives for higher productivity and efficiency beyond those provided by ROR regulation, namely, regulatory lag and retrospective reviews. Overall, a new ratemaking system compatible with increased competition in the electric power industry would be more light-handed and flexible than current ROR regulation. Regulators may come to view the new system as a requisite for firms to succeed in the competitive environment.

Historically, states commissions have had reservations about incentive mechanisms. Regarding partial mechanisms such as power plant productivity incentives,

[4] Flexibility in pricing is required for the firm to compete with other suppliers as market conditions change.

[5] These customers generally are those with the fewest options to the utility's services. Cross-subsidization in the form of predatory pricing is highly unlikely given the irrationality of such a pricing strategy in most circumstances. A regulated firm, on the other hand, especially one subject to ROR regulation, would have an incentive to shift its costs to those markets for which it continues to possess some monopoly power.

their chief concern has focused on whether they have actually benefitted consumers. In theory, a partial incentive system may distort a utility's incentives by focusing its efforts on improving its performance in the targeted area, which may be incompatible with minimizing its total cost of service. For example, a utility may inflate its fuel costs to improve the heat rate or availability of base-load generating facilities. Partial incentives, like most other incentives, may induce a utility to focus intensively on short-term efficiencies and to overly slight longer-term ones.

Experience with partial incentives in the electric power industry has shown that continual commission oversight would be required. The little empirical evidence available shows mixed results regarding the overall effects of partial incentive systems on consumer well-being.[6] This pertains to both power plant productivity and demand-side management (DSM) incentives.[7] Some analysts would argue that partial incentives are most appropriate when a regulated firm has broad monopoly power. Up to now, few partial incentive mechanisms have been instituted to either accommodate or to respond to increased competitive forces in the electric power industry.

State commissions' concerns over broad-based incentive systems such as price caps revolve around their effects on small, so-called "core" customers. Specifically, many commissions worry that price caps, for example, may lower the quality of electricity

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[6] See the contrasting results contained in Sanford Berg and Jinook Jeong, "An Evaluation of Incentive Regulation for Electric Utilities," *Journal of Regulatory Economics*, 3 (1991), 45-55; and Robert J. Graniere, Daniel J. Duann, and Youssef Hegazy, *The Effects of Fuel-Related Incentives on the Costs of Electric Utilities* (Columbus, OH: The National Regulatory Research Institute, 1993).

[7] One objective of DSM incentives is to compensate for the presumably inadequate incentives for DSM investments under traditional regulation. Proponents of DSM incentives argue that both regulatory and market barriers discourage utilities from conducting cost-effective DSM activities. See, for example, Oregon Public Utility Commission, *Investigation into Electric Utility Incentives for Acquisition of Conservation Resources* (Salem, OR: Oregon Public Utility Commission, 1991).

service in addition to increasing prices to core customers, who (by definition) are unable to escape the utility's monopoly grasp.[8]

Some regulators seriously question whether utilities should be given more incentives when they have a legal obligation to be efficient. Interest groups have also argued that "rewards" granted to firms for exceptional performance simply represent bribes.[9] Regulators' negative views on incentives are likely to subside as utilities confront more competition or encounter erosion of their monopoly status.[10] Regulators will likely over time be more favorably receptive to broad-based incentive systems that give utilities an equal opportunity to compete with other suppliers on the basis of both prices and service offerings.

To gain acceptance from state commissions, broad-based incentives such as price caps, at the minimum, would have to address the potential adverse effect of price discrimination on core customers. Regulated firms would have an incentive to practice Ramsey-type pricing, where a disproportionate amount of a firm's fixed cost is recovered from the least price-sensitive customers, namely core customers.[11] Such a pricing strategy, it should be noted, would likely be contrary to the political interests of regulators.[12] Consequently, similar to what has happened in the telecommunications industry, regulators will allow electric utilities pricing flexibility and

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[8] The concern over deterioration of quality of electric service stems form the fact that under price caps a utility would have greater incentive to decrease its costs, including those incurred to improve reliability or to minimize the number of outages.

[9] See, for example, the presentation of John Anderson, at "The Future of Incentive Regulation in the Electric Utility Industry," sponsored by the School of Public and Environmental Affairs, Indiana University and PSI Energy, Indianapolis, Indiana, November 18, 1991.

[10] As noted later, a major reason for this is the realization by regulators that utilities need the opportunity to earn supernormal profits for survival when operating in a more uncertain and risky environment in which they are certain to suffer losses in some aspects of their business.

[11] Ramsey pricing, in a competitive world, would allow the firm to remain financially whole by shifting more of the fixed costs to customers who have the least options of suppliers.

[12] The reason for this is that core customers may be the most politically visible, making it difficult for regulators to raise their rates even though it would improve the financial position of the utility, and thus the ability of the utility to deliver lower cost power in the long term to all its customers, including core customers.

opportunities to earn higher profits but only if core customers receive some degree of protection. One way of achieving this, for example, is to establish price caps for each customers class, thereby protecting residential customers from having to recover revenue deficits encountered by utilities in competitive markets.[13] As an alternative, regulators could require utilities to completely or partially write off their assets, rationalizing that competition has reduced the market value of the utilities' power plants and other facilities.

Regulatory Incentives in the New Electric Power Industry

Chapter 4 of this report identified problems with traditional, ROR regulation in creating adequate incentives for utility innovations. These problems provide the underlying rationale for state regulations to change their ratemaking procedures so as to achieve a more balanced risk-reward relationship for electric utilities. Specifically, traditional state regulation, at least as practiced in recent years, has had an asymmetric reward structure relative to unregulated markets: utilities can sustain large losses for poor management actions and unanticipated outcomes, while enjoying little added benefit from exceptionally good performance. Two general approaches for dealing with this asymmetry exist: reducing risks or increasing profit opportunities for utilities.

The position taken in this report is that reducing risks to the utility (by shifting more risks to consumers) would be incompatible with the increased competitive and risk environment now confronting the electric power industry.[14] As competition increases utilities will face greater risks

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[13] It has been shown, however, that pricing efficiency would improve with a smaller number of price-cap baskets; but more acute price discrimination would also result. See Ingo Vogelsang, "Price Cap Regulation for Telecommunications Services: A Long-Run Approach," *Deregulation and Diversification of Utilities*, Michael Crew, ed. (Boston, MA: Kluwer Academic Publishers, 1989).

[14] Recognition of greater competition in the electric power industry comes from all quarters--utilities, public utility commissions, consumer groups, investment houses, and federal power marketing administrations. See "Survey: Two-Thirds of Utility Execs Consider Retail Wheeling Inevitable," *Electric Power Daily* (January 12, 1994): 3; "WP&L Prefers To Prepare for Retail Wheeling; EEI Attacks Industrials," *Electric Utility Week* (June 7, 1993): 1-2; "For Electrical Utilities, the Future Is Less Than Bright," *The Wall Street Journal* (February 10, 1994): 24-25;

from the dynamics of market forces. In controlling and managing these risks, it can be argued that utilities should govern them in a manner that imposes minimal harm on consumers. Only by holding utilities accountable for their actions would management have the proper incentive to achieve this objective. Alternatively, by passing more of the risks to consumers, utilities become more indifferent to risk management: the mistakes of management are borne more by consumers. A major outcome of competitive and unregulated markets is that firms suffer the most harm from poor performance; the market protects consumers from the inadequacies of management practices. Largely for this reason, firms have a strong incentive to be efficient and to conduct their business so that it is compatible with consumer interests. In maximizing the social benefits of the competition now penetrating the electric power industry, it can therefore be argued that reducing risks to the utility would be counterproductive. Besides, efforts to do so would likely become futile over time as more electricity consumers avoid paying for risks shifted to them by searching out other suppliers. One lesson learned from competition is that it ultimately forces most or all of the risks associated with a firm's operation and investments on shareholders and managers.

In a competitive environment, it is also crucial for utilities to be given flexibility in terms of pricing and other activities, in addition to the opportunity to profit from risk-taking activities: ROR regulation will progressively over time be perceived by electric utilities as a hinderance to offering new services, retaining existing customers, achieving higher earnings and competing overall with other market participants. From the regulator's perspective, continuation of traditional regulation will inflict higher inefficiencies upon the industries, translating into earning losses for the utility or economic losses for consumers or both. Such outcomes are incompatible

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Division of Strategic Planning, California Public Utilities Commission, *California's Electric Services Industry: Perspectives on the Past, Strategies for the Future* (San Francisco, CA: California Public Utilities Commission, February 1993); Maine Public Utilities Commission, *Order for Central Maine Power Company, Proposed Increase in Rates*, Docket No. 92-345, December 14 1993; Charles M. Studness, "The Pressures of Competition," *Public Utilities Fortnightly* (June 15, 1993): 31-32; "Competition Forces S&P Reappraisal of Utilities and Financial Bench Marks," *The Electricity Journal* 6, no. 9 (November 1993): 8-10; "BPA Drafts Radical Restructuring," *The Energy Daily* (February 28, 1994): 1-2; and "Competition Threatens Renewables, Conservation NPPC Report Warns," *The Energy Daily* (February 16, 1994): 1-2.

with the regulatory objective of promoting the public interest.

One implication of increased competition in the electric power industry is that the industry will ultimately be more affected by market forces and less by regulation. Regulators, as some have already found out, will face increased pressures to allow utilities more pricing flexibility and opportunities to earn higher profits. Pricing flexibility will allow a utility to compete on a more equal basis with other suppliers and to prevent what is labeled "uneconomic bypass."[15] Opportunities to earn supernormal profits that are more in line with actual or perceived risks should elicit utilities to undertake more risky, but promising innovations. When the regulatory incentive structure is optimal, a condition that is difficult to achieve in both theory and practice, it should produce the appropriate level of risky or innovative investments from a societal perspective.

Partial Incentives

Most of the existing incentive systems for electric utilities are targeted at a specific area of operation such as fuel costs, DSM activities, and power plant productivity.[16] These partial incentives, for the most part, were adopted in response to some evidence of poor utility management, to political pressure induced by rising electricity prices, or to accelerate utilities' DSM activities. As said earlier, they were not rationalized on the basis of accommodating competition in the electric power industry.

As a general rule, partial incentives can be better defended for regulated firms that have strong monopoly power across their markets. Partial incentives that include rewards as a way of

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[15] Uneconomic bypass can be defined as a situation where a customer leaves a utility for another supplier with lower prices but with higher economic costs. It can be argued that when a utility is able to price as low as its incremental cost, any bypass that occurs would be economic (that is, the switching customers would only go to another supplier that has lower economic costs).

[16] See Edison Electric Institute, *Types of Incentive Regulation: A Primer for the Electric Utility Industry* (Washington, D.C.: Edison Electric Institute, April 1993).

balancing risks and rewards, however, can be beneficial.[17] Some analysts have argued that partial incentives can distort a firm's incentive to minimize its overall cost of service. Experiences with partial incentives have shown that they need to be closely monitored, micromanaged, and frequently adjusted. The little empirical evidence available concerning the actual effects of partial incentives on a utility's cost of service is inconclusive.[18]

Broad-Based Incentives

Price Caps

The broad-based incentive systems that have received the most attention in the regulatory arena include price caps and profit sharing. Each of the two incentive systems is similar in that a firm's prices are not strictly linked to its overall profits and costs.

Price caps or their variants have been adopted by regulators for AT&T's interchange (long distance services), the regional Bell Holding Companies' local exchange services, and for the British natural gas, electric power, and telecommunications industries.[19] The limited empirical evidence on price caps suggests that they can benefit both regulated firms and their customers. For example, large cost savings followed the institution of price-caps regulation in the newly privatized British telecommunications industry. Initially, this benefitted shareholders and, ultimately, consumers in the form of lower prices. Although much of the cost savings was probably derived from privatization *per se*, it is arguable whether their large magnitude would have occurred under a rate-of-return regulatory regime.

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[17] See, for example, the empirical evidence contained in Graniere et al., *The Effects of Fuel-Related Incentives on the Costs of Electric Utilities*.

[18] See Ibid.; and Berg and Jeong, "An Evaluation of Incentive Regulation for Electric Utilities."

[19] See, for example, John E. Kwoka, Jr., "Implementing Price Caps in Telecommunications," *Journal of Policy Analysis and Management* 13, no. 4 (1993): 726-52; and Bernard Tenenbaum, Reinier Lock, and James Barker, Jr., "Electricity Privatization: Structural, Competitive, and Regulatory Options," *Energy Policy* (December 1992).

The performance of price caps suggests that they are effective in controlling the prices of a firm with market power even when profits are left unregulated or loosely regulated.[20] Price caps allow the regulated firm to compete on an equal basis with market suppliers by giving the firm wide pricing freedom and the opportunity to offer new services in the absence of time-consuming, case-by-case regulatory approval. From a political perspective, price caps have the potential benefit of protecting the so-called "core customers" from competition encountered by the regulated firm in other markets. When, for example, where individual price caps are placed on each class of customer, whatever revenues (profits or losses) the utility is able to earn in industrial markets would not directly affect the price charged to residential customers. It would be expected, however, that actual prices to residential and other core customers would be

[20] Ronald R. Braeutigam and John C. Panzer, "Effects of the Change from Rate-of-Return to Price-Cap Regulation," *American Economic Review* 83, no. 2 (May 1993): 191-98.

closer to the allowed price ceiling than would be the case for industrial and other more price-sensitive customers.[21]

Under ROR regulation, in contrast, a firm is able to receive revenues that correspond to its revenue requirements. This implies that wherever the firm receives fewer revenues from one group of customers such as industrial customers it has the right to petition for recovery of increased revenue from others by raising their prices.

When price cap regulation works in a manner that follows its textbook description, it can benefit both the regulated firm and its customers. These benefits include: (1) the firm has a strong incentive to be cost efficient (equivalent to long regulatory lag), (2) customers share in the benefits of a more efficient firm (for example, by initially establishing a high productivity-offset factor), (3) the firm can compete on an equal basis with other suppliers in price-sensitive markets (therefore lowering the likelihood of losing large customers), (4) the firm's prices will move toward efficient levels, and (5) the regulator will encounter infrequent price reviews. Proponents argue that price caps serve a particularly important function during the transition of a heavily regulated industry toward deregulation and more advanced competition.

As with all other incentive and ratemaking systems, price caps have their own problems. First, the firm would have an incentive to provide a lower quality or reliability of service. Second, the firm could engage in cross-subsidizing competitive services with revenues earned from core services (this presumes a single price cap for both services). Third, the firm may earn excessively high or low earnings between formal rate reviews. Fourth, prices would become more discriminatory (although probably more efficient) over time. Finally, consumers may receive a small share of the benefits from a more productive firm.

In the economic literature, a general concern of price caps revolves around the possibility that, under most circumstances, they may not maximize the long-term interests of consumers.[22]

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[21] This implies that competitive pressures would force actual prices in noncore markets to lie below the allowed price ceiling. If not, it can then be questioned whether the specified noncore markets are actually workably competitive.

[22] See, for example, Richard Schmalensee, "Good Regulatory Regimes," *RAND Journal of Economics* 30 (Autumn 1989): 417-36.

Especially in an unstable and highly uncertain environment, higher price ceilings would have to be set to guarantee a firm's financial viability, the firm's earnings would more likely fall outside some "normal" or "reasonable" range, and actual prices would tend to move farther from a firm's actual costs. In sum, price caps in an unmodified form can create both economic and political problems.

Profit Sharing

Profit sharing involves the regulated firm retaining permanently a prespecified portion of earnings outside a certain range. It is typical for a profit-sharing plan to include a "dead band" region within which the firm would retain for its shareholders all the profits actually earned. Profits outside the region would trigger an automatic rate adjustment.[23]

Illustrating how profit sharing would operate, assume the "dead band" is specified in terms of an 10 percent to 14 percent rate of return on equity (with the mean 12 percent representing the firm's cost of equity); and that a sharing arrangement distributes the rates of return outside this range to consumers and shareholders on a 80 percent to 20 percent basis. If, for example, the utility earns 18 percent during a particular period, the utility would lower its rates to "give back" to consumers 3.2 (0.8 x 4) percentage points out of the 4 percentage points it initially earned beyond the "dead band" region. After the rate adjustment, the utility's actual ROR would be 14.8 percent (14 percent + .2 (18 percent - 14 percent)).

Profit sharing has several attractive features. First, within the "dead band" region the utility would have the same robust cost-savings incentives as under price caps. Outside the region, the utility would still have stronger incentives than under ROR regulation to control costs, since it would permanently keep at least a share of the incremental rate of return on equity. Symmetrically, the utility would also share in losses (earnings below the "dead band" region).

Profit sharing also would allow consumers to explicitly and directly benefit from higher

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[23] Much of the following discussion on profit sharing is adapted from Mohammad Harunuzzaman et al., *Incentive Regulation for Local Gas Distribution Companies under Changing Industry Structure* (Columbus, OH: The National Regulatory Research Institute, 1991), 77-79.

earnings outside the "dead band" region. By specifying up-front rate adjustments at different levels of actual earnings, profit sharing would reduce the likelihood of a utility earning extreme profits.

Finally, profit sharing would be fairly simple to apply. In contrast to price caps, it requires no selection of a "correct" price index and productivity offset. Overall, profit sharing is viewed by some analysts as an effective incentive-based mechanism. It would also allow regulators to commit to a ratemaking procedure that places some degree of constraint (although less than under ROR regulation, but more than under pure price caps) on the profits that a utility could earn.

On the negative side, profit sharing, by and in itself, would not improve pricing efficiency. In conjunction with a pricing-flexibility mechanism such as price caps, profit sharing could improve both productive and pricing efficiencies. As with practically all incentive mechanisms along with ROR regulation, however, it would be vulnerable to "gaming" by utilities. As an example, a utility may increase its costs in the near term with the intent of triggering a formal rate review. This problem would be less serious to the extent the utility retains a larger share of the benefits and encounter less frequent formal rate reviews.[24] These two factors would mitigate against perverse incentives when the utility operates near the "bandwidth."

As a third deficiency, a utility would have weaker incentives for controlling costs and innovating than under, say, price caps. The degree of less strong incentives directly relates to the share of increases in the actual rate of return on equity that the utility would be required to return to consumers. In the extreme case where all increases flow back to consumers, profit sharing becomes a cost-plus-type contract. At the other extreme, when the utility retains all the increase, the incentives resemble those under price caps.

Finally, at least compared with price caps, profit sharing would generate more price volatility. As a general rule, a tradeoff exists between minimizing price volatility and earnings volatility. For example, the electric revenue adjustment mechanism (ERAM), which has been implemented in some states to promote utility-financed DSM activities, has the effect of

[24] For example, a requirement may be that formal rate reviews could not be conducted more frequently than once every five years.

stabilizing earnings at the cost of price volatility. Pure price caps, at the other extreme, tend to stabilize prices at the cost of earnings volatility.

Hybrid Plans

The broad-based incentive mechanism, discussed briefly here and illustrated in Chapter 7, represents what can be labeled a "hybrid" price-flexibility/profit sharing plan.[25] Such a plan combines the benefit of pricing flexibility in a competitive environment with the sharing of benefits to both consumers and shareholders from the realization of higher profits. Although limiting profits would weaken the utility's incentive to control costs, it adds stability to the incentive plan--thus, constituting a major reason for the profit sharing component.[26] In part, the plan does this by directly and expeditiously returning a share of the utility's increased profits to consumers.

The hybrid plan becomes more attractive when regulators have little information on the future productivity of a utility. In such an environment, the profits of a utility would more likely deviate farther from normal levels. Compared with price caps, for example, the hybrid plan also would require less frequent periodic performance reviews: the utility's earned rate of return would be expected to stay within a narrower range.[27] Overall, the hybrid plan has attractive features from an economic perspective: it would give a utility more incentive to control its costs and to innovate relative to ROR regulation, in addition to allowing the utility to freely adjust its prices in response to changed market condition.

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[25] Hybrid plans are discussed in Berg, *The Potential for Using Performance Indices to Provide Regulatory Incentives*; and Kwoka, "Implementing Price Caps in Telecommunications."

[26] The stability effect lies with the presumption that when realized profits lie farther from normal profits (for example, profits corresponding to the utility earning its cost of capital) it is more likely that the plan would either be rescinded or modified in some form to reduce the likelihood of similar future profit volatility.

[27] Conducting less-frequent "true-up" performance reviews would increase the incentive for cost efficiency and reduce administrative costs for both the commission and the utility. A plan that evaluates the parameters of the price-cap formula and the utility's actual profits on a yearly or short-term basis would create incentives similar to those under rate-of-return regulation.

From a political perspective, a hybrid system has the attractive feature of containing a "safety net" that prevents the utility from earning either extremely high or extremely low profits. Unlike pure price caps, the hybrid plan mitigates against the utility earning extreme profits, but at a cost of blunting efficiency incentives for the utility. One major benefit of this outcome is that, by confining profits within some "reasonable" range, it is more likely that a plan would avoid opposition from either the general public or from the utility.[28]

The hybrid plan is also politically attractive in that it makes the effect of a utility earning higher profits on lowering rates to consumers more publicly visible and direct than price caps. If a plan could be shown to benefit utility shareholders, core consumers, and noncore customers--a win-win-win situation--it would likely become more acceptable to both regulators and the general public. Pure price caps, in contrast, could conceivably retain almost all of a utility's efficiency gains for shareholders. This could happen when

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[28] Experiences in the telecommunications industry in this country and abroad have also shown that "extreme profits" would tend to cause changes in the price-cap formula. This reduces the effectiveness of the plan by weakening incentives for cost control and innovation.

the negotiated or prespecified productivity-offset factor is set at a low value relative to what is actually achieved.[29]

Summary Assessment of Regulatory Incentives

Table 6-1 lists the strong and weak attributes of different regulatory incentives that can directly or indirectly be applied to IGTs. Partial incentives include the "Cost-Sharing of Life Cycle Costs," mechanism, preapproval options, prudent abandonment rules, and power plant performance plans. The preapproval plans, in particular those that pertain to actual expenditures, have the serious problem of shifting risks to consumers.

One observation that bears repeating, revolves around the principle that, in a competitive or even quasi-competitive marketplace, it becomes more difficult from an economic perspective to justify any cost-plus pass-through mechanisms such as preapproval of expenditures. This is especially true when preapproval excludes any cost cap, which would amount to cost-plus contracts without hindsight review. In a competitive environment, as pointed out earlier, a utility should assume more of the risks, as well as being give more opportunities to earn higher profits. It seems sensible from both an economic-efficiency and equity perspective to establish a symmetric condition for regulated firms facing varying degrees of competition. This means placing fewer bounds on the utility with regard to both risks and profits.

Preapproval regulatory rules, especially when they encompass the expenditures associated with a particular action, impose four major problems. First, they place commissions directly in the role of second managers. Assuming such a function, commissions are accepting a responsibility that arguably falls beyond their capabilities and legal purview.

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[29] Assume, for example, that the regulator sets a productivity-offset value of 1 percent at the time of a formal review and the subsequent realized productivity is 4 percent. In effect, the utility retains 75 percent of the actual productivity gains, at least until the next formal review.

TABLE 6-1
STRENGTHS AND WEAKNESSES OF DIFFERENT INCENTIVE OPTIONS

Option	Strengths	Weaknesses
Price Caps	● Strong incentives for efficient cost control ● Enhanced profit opportunities ● Flexible pricing accommodates market conditions ● Elimination of retrospective reviews	● Lower quality of service ● Price discrimination ● Possibility of utility earning "extreme" profits ● High initial administrative costs ● Prices may deviate from utility's actual costs ● Consumers may benefit little from actual productivity improvements
Profit Sharing	● Strong incentive for cost control in "dead band" region ● Consumers explicitly and directly benefit from higher profits ● Relatively simple to apply	● No effect on pricing efficiency ● "Gaming" ● Price volatility
Price Caps/Profit Sharing (Hybrid System)	● Recognition of political problems associated with price caps ● Allowance of pricing flexibility along with opportunities for utility to earn supernormal profits ● Avoidance of retrospective reviews	● Price discrimination ● Lower quality of service ● "Gaming" ● Price volatility
Cost Sharing of Life Cycle Costs	● Symmetric treatment of rewards/risks for new technologies ● Avoidance of retrospective reviews	● Partial incentive system ● Litigation over parameters
Preapproval of Plans (e.g., IRP)	● Reduction of regulatory risk ● Public participation	● Requirement of significant up-front information ● Disincentives for executing efficient plan (moral hazard) ● Disincentives for flexible planning
Cost Sharing of Construction Costs	● Incentive to avoid large cost overruns ● Avoidance of retrospective reviews	● Partial incentive system ● Potential for creating operating problems ● Litigation over bench mark
Preapproval of Expenditures (Rolling Prudence)	● Reduction of regulatory risk ● Exposure of major problems in timely fashion	● Pressure for regulators to make quick decisions ● Disincentives for flexible planning ● Imposition of onerous administrative requirements on utility and regulator
Preapproval of Specific Projects	● Reduction of regulatory risk ● Less risk to ratepayers compared with preapproval of entire plan	● No explicit rewards ● Moral hazard ● Difficulty of dealing with exceptional outcomes
Prudent Abandonment Rules	● Reduction of utility incentive to continue construction under uneconomical conditions ● Reduction of uncertainty to utility	● No explicit rewards ● Moral hazard possibility
Power Plant Performance Bonus	● Inducement of efficient power plant utilization and operation ● Partial offsetting of construction risks	● Possible distortion of utility resources ● Possible micromanagement by regulators ● Possible constant adjustment as conditions change

Second, preapproval severely diminishes the utility's responsibility for decisions: when the utility is assured of recovering all of its actual costs (an extreme case of preapproval) the utility becomes more indifferent to the ultimate outcomes. The problem of what economists call "moral hazard" becomes pronounced as incentives for efficient management practices diminish whenever the utility enjoys the assurance of cost recovery. As a matter of public policy, risk should be shifted to those making decisions (for example, the utility) and to where it is less costly (ambiguous). For political purposes, commissions also are unlikely to preapprove facilities that deploy new and risky technologies. Preapproval in this case means that cost overruns and other problems typically associated with new technologies would be shifted to consumers. This prospect would turn commissions away from the preapproval option for new technologies. A less extreme form of preapproval, for example, sanctioning the construction of a new IGT facility but leaving open the possible review of the actual costs after-the-fact, would likely be more acceptable to commissions. Also more acceptable to commissions would be the intermediate case where preapproval of construction costs would coexist with symmetrical sharing of overruns and underruns.

Third, preapproval requires a commission to have access to detailed information. In performing the role of second manager, commissions would need to have the same information as a utility manager in making sound decisions. Even with adequate information, managers need the expertise and the skills to interpret it and apply it correctly. Utility managers are paid high salaries to do just this; it is highly questionable whether regulators could and, more fundamentally, whether they should.

Fourth, a utility would tend to stay too long with a plan or facility that was preapproved by a commission. This presents a problem when conditions change, warranting new action to be taken by the utility.

A second observation is that the plan labeled "Cost Sharing of Life Cycle Costs" may be construed as substitutable for a combined "power plant performance" plan and "preapproval" plan. The cost sharing plan represents a more comprehensive incentive than most other partial incentives, which focus only on a single performance attribute. Consequently, it mitigates against the possible distortion from a tradeoff between construction and operating efficiencies (see

Chapter 7 for a detailed description of this plan).

A third observation is that in a competitive marketplace, as discussed earlier, broad-based incentives such as price caps and profit sharing become more defensible. Since broad-based incentives have just begun to be introduced to the electric power industry, state commissions should exercise caution in deciding whether to sanction the more radical price caps or some more moderate system such as profit sharing. A reasonable cause of action, and one supported in this report, is for commissions to recognize the potential benefits of a hybrid comprehensive incentive system in an increasingly competitive electric power industry. Such a system could achieve much of the efficiency benefits from price caps, while extenuating the possible political backlash from a utility earning "excessive" profits. In addition, the hybrid system should enhance (relative to ROR regulation) the incentive of a utility to innovate: prudence reviews would be minimal or eliminated, regulatory lag would be lengthened, the utility would achieve higher long-term profits from successful innovations, and regulatory commitment to the plan would likely be sustained. Chapter 7 illustrates one particular hybrid system.

The next chapter present two incentive systems for consideration by state public utility commissions. The first is a broad-based hybrid system. The second is the "Cost Sharing of Life Cycle Costs" mechanism. The hybrid system or a variant is presented as a mechanism that will likely be closely studied, and in some instances adopted, in the future by state commissions. In the interim period state commissions may, however, want to consider a partial incentive system such as the "Cost Sharing of Life Cycle Costs" mechanism directed at the promotion of IGTs. Such a system should be given serious consideration for two major reasons. First, it may be several years before state commissions are willing to adopt the broad-based incentive systems discussed earlier. Since these systems represent significant departures from traditional regulation, commissions may rightly oppose their approval until convinced of their superiority over traditional regulation; this may take some time to achieve. Second, special incentives directed at IGTs can explicitly account for the potential public benefits that could accrue to a state or to areas within a state. Although spillover effects can arguably be better dealt with at the national level (see Chapter 7), states may find it in their self-interest to justify supplemental actions that would optimize the benefits of IGTs within their jurisdictions.[30]

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[30] Incentives rationalized on the basis of spillover benefits, at least in theory, should not be considered subsidies. They should instead be viewed as a "second best" mechanism directed at placing IGTs on a "level playing field" with technologies that have fewer or no spillover benefits. As discussed in Chapter 7, however, such incentives in many instances are unlikely to be the most appropriate way to deal with spillover benefits.

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CHAPTER 7

ANALYSES OF SELECTED INCENTIVE MECHANISMS

Introduction

Many policymakers have expressed concern that electric utilities are ignoring innovative generation technologies (IGTs) despite their potentially large environmental and economic benefits. There are two fundamental reasons for concern. First, these new technologies offer benefits that cannot be fully captured by the utility that adopts them, nor even by the state in which the technologies are implemented. Thus, utilities and their regulators may have incentives to delay adoption, hoping to capture "spillover" benefits from early innovators. Second, even if the above spillovers did not exist, present forms of public utility regulation may offer inadequate incentives for firms to adopt risky new technologies. The following sections analyze these two justifications for public policies toward IGTs. The analysis focuses on the opportunities available to public utility commissions, and argues that reform of utility regulation is more likely to be effective in addressing the second concern than the first one for many states, but arguably with exceptions.

The key points of this chapter can be summarized as follows. The next section discusses the spillovers associated with the adoption of IGTs, and discusses potential policy responses by federal and state governments. It concludes that reform of public utility regulation is not the most promising avenue for addressing these concerns, and that they are better dealt with through explicit environmental regulation, probably at the national rather than state level (although it may be in the self-interest of some states to partly address spillover effects), and through federal government support for the commercialization of new technologies. The subsequent section summarizes the ways in which state public utility regulation may bias utilities against the adoption of innovative technologies, drawing heavily on the findings in Chapter 4 of this report. Three potential barriers to the adoption of IGTs are identified: too short a period of regulatory lag, distortionary upper and lower bounds on earnings, and regulatory hindsight reviews. This chapter also outlines some alternatives to traditional regulation that go under the heading of "incentive regulation," discusses the key principles underlying these alternatives, and examines the extent to which such mechanisms can be applied to providing incentives for the adoption of new technologies. This section also reviews two recent studies of particular incentive plans for encouraging the adoption of technologies for electricity generation. Drawing on the foregoing analysis, this chapter proposes two incentive mechanisms designed to give electric utilities enhanced incentives to innovate without requiring government to pick technological winners. One is a sliding-scale mechanism that shares profits between the firm and its ratepayers. This chapter presents a simulation analysis of the effects of profit sharing, and shows how a properly designed sliding-scale plan can level the playing field between conventional and innovative generating technologies. The second mechanism can be categorized as a partial incentive, called "Cost Sharing of Life Cycle Costs," that is designed to meet performance and cost objectives for a single generation facility. A numerical analysis of how the mechanism works is presented.

Environmental and Informational Spillovers from IGTs

Markets often do a poor job of allocating goods whose costs or benefits spill over to people who did not buy or sell them. Such spillovers (called externalities by economists) are particularly important in the areas of environmental quality and the creation of new knowledge, both of which are important to the design of incentives for new technology adoption. For example, coal-burning utilities in the Midwest emit sulfur dioxide (SO_2) that creates acid rain in the Northeast; cleaner generation technologies promise benefits well beyond a given utility's service territory. Similarly, one firm's experience with a new technology generates information that can be of value to all other potential adopters of the technology.

The standard economic solution to the problem of externalities is either to create a market for the rights to use the scarce resource in question, or to tax their use directly, through emissions taxes, effluent fees, and so on. If either of these is done correctly, the externalities are internalized into the market system, so producers and consumers will make decisions that reflect the full social costs of their actions. Unfortunately, properly internalizing externalities is not always easy. The remainder of this section discusses how the two above types of externalities affect the proper design of incentives for technology adoption.

Environmental Externalities

One of the advantages of IGTs is that they lessen pollution, in addition to any other cost and/or performance benefits they may offer. If all the relevant environmental costs of power generation were accounted for in prices, and environmental externalities were thus properly internalized, environmental benefits would not justify special incentives for new technologies. If these environmental benefits are not properly reflected in prices, however, utilities will understandably lack motivation to adopt new, environmentally friendly, technologies. Internalizing environmental externalities in an optimal manner is difficult to do. States have increasingly looked for ways to internalize environmental costs, for example, by enacting legislation.

Existing federal and state regulations attempt to internalize at least some of the relevant environmental costs. The federal clean air legislation of 1970 and 1978 each internalized some costs; the 1990 Amendments to the Clean Air Act did even more. For example, the federal Clean Air Act amendments of 1990 established a market for emission permits, each of which gives the bearer the right to emit one ton of SO_2 into the air. A utility that adopts a cleaner generation technology will generate excess SO_2 permits that it can sell to the highest bidder. Assuming that the Congress correctly reflected the preferences of the American polity in its decision, then the emissions market should--at least in principle--solve the SO_2 externality problem. In addition, a growing number of states are considering the use of price "adders" that attempt to increase the price of electricity generated from various technologies to reflect its full environmental impacts. Whether state regulators are the proper formulators of environmental policy, whether the "adder" approach is a desirable one, and whether the states pursuing this path are implementing it effectively, are highly controversial issues.[1]

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[1] Joskow, for example, vigorously condemns the entire approach. See Paul L. Joskow, "Weighing Environmental Externalities: Let's Do It Right!" *The Electricity Journal* (May 1992),

In general, economic theory suggests that internalizing externalities directly, rather than subsidizing particular technologies, is the preferred route to solving the environmental problems associated with electricity production.[2] Any single technology will produce a bundle of different environmental effects, which must be aggregated and compared to those produced by other technologies in order to choose which technology to subsidize. Furthermore, this process must be repeated whenever a new technology is invented. Pricing out external effects directly (through taxes or emissions markets) leaves the actual choice of technology to firms rather than government officials, with attendant flexibility, informational decentralization and incentives for further technological improvement. Thus, on basic principles, it is probably not economically efficient for state or federal bodies to implement environmental policy by providing specific incentives for preferred technologies. If, however, pricing and other direct incentives for internalizing externalities do not exist or are inadequate, then targeted regulatory incentives become more defensible.

Informational Externalities

A second relevant externality arises because the first commercial adoptions of new technology constitute an "experiment" that provides valuable information about how to operate the technology successfully. The first few firms to adopt the technology may have costly technical problems, later solve those problems, and then find it difficult to withhold information about the technology's success from other potential adopters. Thus, potential adopters have incentives to delay adoption and "free ride" on the information-generating experiments of others. Furthermore, state regulators often have little incentive to induce their utilities to be the first to undertake the risks of adopting a new technology. This problem provides a rationale for federal

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53-67.

[2] One needs to distinguish between a permanent subsidy and a temporary subsidy. While the former is difficult to justify under almost any condition, a temporary subsidy may be warranted to bolster the development and precommercialization of new technologies in the absence of "first-best" policies and practices.

government support of adoption by a small number of utilities or for state government incentives (for example, in the form of regulatory incentives) to compensate utilities for technological and other first-mover difficulties that are likely to arise. The U.S. Department of Energy's (DOE) Clean Coal Technology (CCT) program addresses this problem directly,[3] and has funded the demonstration of various coal-burning generation technologies since 1986;[4] this program was reaffirmed in the Energy Policy Act of 1992 (EPAct).

Implications for State Regulators

Both the above spillover problems may justify policies to support the adoption of IGTs. Because these spillovers have important effects that go beyond state lines, state regulatory commissions are often not the appropriate bodies to implement such policies. There are some cases, however, where states will find it in their self interest to help commercialize certain IGTs by partially offsetting spillover effects. Some states, however, may find it in their self-interest to promote particular technologies. A state with significant potential geothermal resources might be more inclined to help commercialize geothermal power since this could lead to the development of a market for economic sales in the future. Similarly, the major coal mining states would have more of an interest in commercializing CCTs than other states, because successful commercialization of IGCCs, for instance, could mean expanded future coal markets. In the remainder of this report, economic distortions created by existing regulatory policies will be the target of policy proposals.

Public Utility Regulation and Innovation

It is often argued that firms subject to regulation have inadequate incentives to innovate.

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[3] Another rationale articulated by DOE for such support revolves around the potential benefits of CCTs to create new jobs, increase exports, and improve environmental conditions.

[4] DOE also has funded programs to promote noncoal generation technologies.

For example, Rose and Mor[5] assert that even after the successful demonstration of CCTs, utilities are unlikely to adopt the new technologies because they still represent incompletely tested technology, involve large capital investments, may be deemed "imprudent" by regulators if costs turn out to be higher than expected, and face considerable uncertainty regarding future environmental regulations. Some of these concerns are also discussed earlier in this report. In particular, that analysis argued that up through the 1970s utilities often adopted innovative capital-intensive technologies, but that since the early 1980s the threat of prudence review has had a chilling effect on the adoption of risky new technologies.

The limited evidence on innovation by utilities in the "post-prudence review" era supports the notion that utilities are no longer ardent adopters of new technology. As of 1992, NUGs had an installed capacity of 2,325 megawatts (MW) using fluidized bed combustion, a clean coal technology. The corresponding value for utilities is 300 MW. Both of these figures represent clean coal generation without government funding. Also, as of 1992, NUG installations of hydro, geothermal, wind, and solar power had installed capacities of 3,033, 1,008, 2,067, and 389 MW, respectively.[6] For the 1992 to 2001 period, utilities planned to add 644 MW of new capacity using four innovative technologies: atmospheric fluidized bed combustion, fuel cells, photovoltaics, and wind turbines; this represented 0.82 percent of total planned generating additions by utilities. For the same period, nonutility generators planned to add 680 MW of new capacity using atmospheric fluidized bed combustion, wind turbines, and solar-powered steam; this represented 3.56 percent of total planned generating additions by nonutility generators.[7] This evidence points to the fact that regulated utilities have recently been, and continue to be, less aggressive users than nonutility generators of IGTs. These figures are consistent with the concerns voiced by the DOE regarding the reluctance of utilities to adopt innovative new technologies in the post-prudence era.

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[5] Adam Rose and Amit Mor, "Economic Incentives for Clean Coal Technology Deployment," mimeo, Pennsylvania State University (June 1992).

[6] Edison Electric Institute, personal communication.

[7] See North American Electric Reliability Council, *Electricity Supply and Demand 1992-2001* (Princeton, NJ: North American Electric Reliability Council, June 1992).

Even assuming that regulators perfectly represent the interests of consumers, there are two major potential sources of slippage between the socially desired rate of innovation and the innovative activities of the regulated firm. First, the incentives presented by the regulatory environment may distort the firm's choices, so that it fails to take actions that are in *consumers'* best interests. For example, the firm may have incentives to pursue or avoid risks to a greater or lesser extent than desired by the firm's customers.[8] Relatedly, the firm may not choose the optimal degree of vertical integration.[9] Second, given the incentive structure facing the firm, managers within the firm may lack incentives to take actions that are in the *firm's* best interests. One problem is that the firm's managers may not work hard enough to reduce costs. Another is that managers may avoid risky projects with positive expected value, perhaps because they lack incentives to gather information about alternative technologies and thus make poor adoption decisions.[10]

As discussed in Chapter 4, there are three key aspects of regulation that distort the firm's propensity to innovate. First, the limited regulatory lag between rate reviews encourages utilities to pursue projects with short payback periods. Second, regulation limits both the upside and the downside profitability of the firm, curbing the firm's earnings as well as the risk it faces. Historical experience suggests that until the mid-1970s, limits on risk were the more important of the two constraints, and may well have *encouraged* innovation by electric utilities. Third, in the 1980s

[8] See the earlier discussion in Chapter 5 on this possible problem.

[9] See Lyon and Hackett for more on the regulated firm's incentives to provide vertically integrated service. (Thomas P. Lyon and Steven C. Hackett, "Bottlenecks and Governance Structures: Open Access and long-Term Contracting in Natural Gas," *Journal of Law, Economics, and Organization,* forthcoming.) Baron and Besanko and Gilbert and Riordan offer formal models that address the optimal degree of vertical integration under regulation. In all of these papers, the regulator faces a tradeoff between the increased upstream competition that results when power generation is separated from transmission, and the reduced informational costs possible under vertical integration. (See David Baron and David Besanko, "Information, Control and Organizational Structure, *Journal of Economics and Management Strategy* (1992), 237-276; and Richard Gilbert and Michael Riordan, "Industry Organization and Regulatory Performance," mimeo, University of California at Berkeley (1992).)

[10] For further discussion, see Richard A. Lambert, "Executive Effort and Selection of Risky Projects," *The RAND Journal of Economics* 17, no. 1 (Spring 1986), 77-88.

regulators disallowed the recovery of costs of new generating units that looked bad in hindsight, even if the decisions to build the plants were prudent at the time they were made. This new element in the regulatory equation may give the firm incentives to reduce the odds of a bad outcome by avoiding risky new technologies.[11]

In proposing regulatory reform, then, the overriding concerns would appear to be *symmetry* and *commitment*. Symmetric regulatory treatment of gains and losses make the firm's profits a linear function of costs, thereby preserving the ranking of different projects based on minimum expected cost. Commitment to the regulatory proposal assures the firm of enough time to recoup its innovation expenses and means the regulator will not renege when it comes time to allow the firm to reap the rewards of good performance.

In contrast to its powerful effects on the firm's profits, regulation has only a limited effect on the transmission of the firm's objectives to its own managers. This transmission is accomplished through the firm's compensation system, which is typically not micromanaged by public utility commissions.[12] Incentive problems may arise because the individual manager tends to be risk-averse, even though stockholders reward the firm as a whole for risk-neutral behavior. Placing some risk on the manager encourages him to work hard to cut costs and to thoroughly study innovative possibilities. Too much risk, however, may be counterproductive, causing the manager to strictly prefer low-risk/low-payoff activities and therefore to fail to gather enough information about new technologies.[13] One way to ameliorate these adverse incentives is to insure the manager against bad outcomes while offering incentives for good outcomes (for example, by

[11] Risk-aversion at the firm level, however, does not appear to be a significant concern to investors: investor-owned utilities (IOUs) are typically held as part of a portfolio of investments; since investors can diversify their holdings to conform with their own risk preferences, they do not demand risk-averse behavior by the firms in which they invest; instead, investors want managers to maximize the expected value of the firm.

[12] For a good discussion of the design of compensation systems, see Paul Milgrom and John Roberts, *Economics, Organization, and Management* (Englewood Cliffs, NJ: Prentice Hall, 1992).

[13] A model of this problem is presented in Lambert, "Executive Effort and Selection of Risky Projects."

giving him stock options). Another possibility is to reward the manager for having his proposals accepted by upper-level management, rather than rewarding him based on the *outcomes* of his proposals.[14] Because regulation plays only a modest role in executive compensation, this report concentrates on the incentives regulation creates at the level of the firm, though acknowledging that in some cases incentive problems at the level of the individual manager may be important as well.[15]

[14] These and other ideas are discussed by Milgrom and Roberts, *Economics, Organization, and Management*.

[15] It should be noted that a career-motivated manager will not always eschew risky projects, because project risk and the individual manager's reputational risk are not the same thing. Hermalin argues that risk-averse managers may wish to avoid undertaking projects that reveal information about their true managerial abilities. (Benjamin E. Hermalin, "Managerial Preferences Concerning Risky Projects," *Journal of Law, Economics, and Organization* 9, no. 1 (April 1993): 127-35.) Then, if the riskiness of projects is observable by others, the manager may prefer risky projects because they make it more difficult to infer the manager's true abilities.

Alternatives to Traditional Regulation

There is growing interest among regulators in policy reforms that provide stronger incentives for efficient operation than does traditional rate-of-return regulation. Though the term "incentive regulation" is commonly used, it remains vague enough to be confusing. As used, it encompasses such seemingly diverse regulatory approaches as:

- **Price caps**: The average price on a basket of services can rise no faster than a bench mark level of inflation, for example, CPI - X (the consumer price index less a measure of expected technical productivity, X).
- **Sliding-scale (or profit-sharing) regulation**: Profits outside a "deadband" are shared between the firm and its customers.
- **Yardstick regulation**: Prices are based on the costs of comparable firms, rather than the firm's own costs.
- **Cost sharing**: The regulator sets a cost target, and divergences from the target are shared between the firm and its customers.

Basic Principles of Incentive Regulation

While these various approaches seem at first glance to have little in common, they can in fact be ordered in a simple fashion based on the "power" of the incentive system involved. High-powered and low-powered incentives may be distinguished by the extent to which the firm's revenues track its own costs.[16] Suppose the regulator sets Revenues = a + b * Costs. A low-powered incentive system sets b = 1. Under this sort of cost-plus regulation, the firm has no incentives to hold down its costs, since they are passed through directly to consumers. At the other extreme is a high-powered incentive system with b = 0. Under this sort of fixed-price regulation, the firm's revenues are outside its control and profits can only be raised by cutting costs. This situation parallels that of perfect

[16] The following discussion is based on Jean-Jacques Laffont and Jean Tirole, *A Theory of Incentives in Procurement and Regulation* (Cambridge, MA: The MIT Press, 1993).

competition, under which the firm is a price-taker. Price caps and yardstick competition are two different ways of separating the firm's revenues from its costs. Price caps index (completely or partially) to an economy-wide base, while yardstick regulation indexes to the performance of comparable firms in the same industry; neither sets price based on the firm's own current-period costs. Between the extremes of cost-plus and fixed-price regulation are systems with $0 < b < 1$, such as cost-sharing and profit-sharing (sliding-scale) plans. The above possibilities are illustrated in Figure 7-1.

As regulatory systems, high-powered incentives do not necessarily dominate low-powered ones in terms of improving consumer welfare or societal welfare. They typically rely heavily on the regulator's imperfect knowledge of cost and demand conditions. The firm, for example, may earn large profits if the revenue requirement is set too high, and the firm's viability may be threatened if revenues are set too low. Neither of these outcomes is viewed with favor by regulators, in part because strong political pressures may follow. As a result, potentially high-powered systems such as price caps are often tempered with profit sharing or cost sharing to reduce the impact of the regulator's incomplete and imperfect information. In addition, high-powered systems must be carefully designed to adapt to a changing environment. For example, price caps generally are indexed to exogenous indices that track costs outside the firm's control. In this regard, yardstick competition is probably preferable to price caps, since it automatically incorporates any cost changes that affect all the yardstick firms in common.

While the academic literature has not identified policy implications so straightforward as "always split deviations from the cost target 50-50 between the firm and its consumers," some general guidelines are beginning to emerge. (As shown later, however, a theoretical basis exists for a symmetric sharing rule.) Consider, for instance, sliding-scale regulation. Suppose the regulator worries about the firm slacking off in its pursuit of cost-reducing activities, but has a reasonably good feel for the firm's underlying productivity level, perhaps as a result of historical experience. Lyon shows

Fig. 7-1. Revenues for three bench-mark cases.

that profit-sharing regulation should begin with a price level close to that which would be optimal for pure price caps.[17] Because this is a challenging target, profit sharing is desirable, and it may be optimal for consumers to bear a greater share of the firm's losses than of its gains. In an analysis of cost-sharing regulation, Schmalensee shows that as uncertainty about the firm's underlying cost structure increases or as technological opportunities expand, the share of costs borne by consumers should increase as well.[18] Thus, uncertainty should push regulators toward cost-plus regulation.

Many of the incentive systems that have been implemented in the electric utility industry have been targeted narrowly toward such performance measures as the capacity factor, the heat rate, or the construction cost for particular generating units, or fuel and purchased power costs. On theoretical grounds, these "partial" incentive systems might be expected to perform less effectively than incentives targeted toward the firm's overall performance: the firm has incentives to concentrate its efforts on the particular measures being rewarded, while ignoring others. For example, Joskow and Schmalensee argue 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."[19] The problem is similar to Averch and Johnson's well-known result that a firm rewarded only for the level of capital it installs will have incentives to overcapitalize, absent *ex post* reviews and assuming, as did Averch and Johnson, that the returns on capital exceeded

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[17] Thomas P. Lyon, "A Model of Sliding-Scale Regulation," mimeo, Indiana University, 1993.

[18] Richard Schmalensee, "Good Regulatory Regimes," *The RAND Journal of Economics* 20, no. 3 (Autumn 1989), 417-36.

[19] Paul L. Joskow and Richard Schmalensee, "Incentive Regulation for Electric Utilities," *Yale Journal on Regulation* 4, No. 1 (Fall 1986), 44.

the costs of capital.[20] While empirical evidence is limited, Berg and Jeong[21] find that incentives for high generating plant utilization and low heat rate did not improve *overall* operating cost performance.[22] A recent report by The National Regulatory Research Institute,[23] however, suggests that they did. In fairness, however, it must be noted that part of the reason regulators use partial systems is that more comprehensive systems--be they based on the firm's costs or its earnings--run into problems with the measurement of capital costs. Estimating the cost of capital is generally a contentious issue in rate hearings, in part because accounting data require considerable interpretation and the firm has private information not available to the regulator.

Although partial incentive systems can create perverse incentives, some are less distortionary than others. Fixed-proportion production processes,[24] in which the firm has no leeway to substitute one input for another, are the best targets for partial incentive plans: the firm is unable to inflate the use of certain inputs such as labor and materials to improve its performance

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[20] Harvey Averch and Leland L. Johnson, "Behavior of the Firm under Regulatory Constraint," *American Economic Review* 52 (December 1962), 1053-69.

[21] Sanford Berg and Jinook Jeong, "An Evaluation of Incentive Regulation for Electric Utilities," *Journal of Regulatory Economics* 3, no. 1 (1991), 45-55.

[22] Berg and Jeong's finding of the disappointing performance of partial incentive schemes for electric utilities is consistent with the results obtained by implementing the Prospective Payment System (PPS) within the Medicare system. This plan set fixed levels of reimbursement that Medicare would give hospitals for each of over 400 illness categories. The introduction of PPS brought a sharp reduction in hospital costs in its first year of implementation, but costs then resumed their previous rate of growth. The problem, at least in part, is that Medicare covers only a fraction of a hospital's total business, and is thus a partial incentive scheme. The hospital is given incentives to shift costs to other customers not regulated under the Medicare system. For more discussion, see S. Guterman et al., "The First Three Years of Medicare Prospective Payment: An Overview," *Health Care Financing Review* 9, no. 3 (Spring 1988), 67-77.

[23] Robert Graniere, Daniel Duann, and Youssef Hegazy, *The Effects of Fuel-Related Incentives on the Costs of Electric Utilities* (Columbus, OH: The National Regulatory Research Institute, 1993).

[24] Fixed proportion means that the ratios of different inputs such as labor, fuels, and capital remain relatively constant over varying levels of electricity generation because of technological constraints.

in the targeted area of operation. Averch-Johnson overcapitalization, for example, cannot occur in this setting. Partial incentive systems also may be promising if quality standards on other dimensions of performance are well-developed and quality is observable. Joskow and Schmalensee suggest that "more systematic prudence reviews of construction costs should be developed. These might involve statistical yardstick comparisons with costs elsewhere."[25] The workability of such an incentive system presumably hinges on the existence of construction standards exacting enough to eliminate most instances of quality-reducing cost-cutting.

Applicability to Innovation

To what extent can the incentive mechanisms identified in the literature be applied to the firm's innovative activities? Most of the analysis in the literature does not consider the possibility that the firm may be choosing between discrete options with different levels of risk. Thus, a system designed to induce efficient innovation needs some additional constraints imposed upon it, relative to the more traditional incentive problem where the goal is simply to induce the firm to work harder. The most important addition is that the firm's rewards should be a linear function of cost, to avoid imposing artificial risk-preferences.[26]

Consider a simple profit-sharing plan with an initial price p_0, where the firm is allowed to keep a fraction α^U of earnings when costs are below p_0 and a fraction α^L
when costs are above p_0. Thus profits are:

[25] Joskow and Schmalensee, "Incentive Regulation for Electric Utilities," 46.

[26] Burness, Montgomery, and Quirk present a simple model showing how regulation can induce risk-seeking behavior. (See H. Stuart Burness, W. David Montgomery, and James Quirk, "Capital Contracting and the Regulated Firm," *American Economic Review* 70 (1980), 342-54.)

$$\pi(c) = \begin{cases} \alpha^U (p_0 - c)q(p_0) & \text{if } c < p_0 \\ \alpha^L (p_0 - c)q(p_0) & \text{if } c > p_0 \end{cases} \tag{7-1}$$

Now suppose that $\alpha^U < \alpha^L$, so that profit as a function of c is concave, as shown in Figure 7-2. As a result, the firm would be better off to stick with a technology that had a cost of $c = p_0$ for certain, rather than to experiment with a technology that had a 50 percent chance of $c = .5p_0$ and a 50 percent chance of $c = 1.5p_0$. (The average of the profits at these two cost levels is strictly less than the profit at the average of the two costs.) The shape of the profit-sharing function has induced the firm to act as if it were risk-averse. On the other hand, setting $\alpha^U > \alpha^L$ would induce the firm to act as if it were risk-seeking. In order to avoid either of these biases, the regulator should use a symmetric sharing rule, where $\alpha^U = \alpha^L$.

Recent Studies of Incentives for CCTs

The DOE has sponsored a number of reports on incentives for the development of CCTs. Because they are closely related to the preceding discussion, two of these reports are reviewed briefly below.[27] The focus here is on their implications for regulatory reform.

Lawrence Berkeley Laboratory

In September 1989, Lawrence Berkeley Laboratory (LBL) issued a report done for the DOE that presented a "performance based cost-sharing system for the Clean Coal

[27] Rose and Mor also examine various incentives for the adoption of clean coal technology, but their approach focuses on fiscal incentives, such as tax breaks, which are generally beyond the purview of state regulators. (See Rose and Mor, "Economic Incentives for Clean Coal.")

Fig. 7-2. An example where profit is concave in costs.

Technology program." In the report, Kahn and Stoft provide a thorough analysis of a bidding system proposed for use by the DOE in awarding contracts to develop new CCTs. The authors propose that, in any given solicitation, the DOE specify in advance a lump-sum subsidy[28] to be awarded to winning contractors, and then require each bidder to state the minimum operating subsidy it would require to undertake its proposed project. The operating subsidy would be some dollar amount per megawatthour produced, so it would implicitly reward high capacity factors. As a result, it can be viewed as a system for cost-sharing between the government and the contractor. DOE would select the project(s) that bid the lowest operating subsidy. While the study does not claim to identify the *optimal* auction format, it argues that "we would have to investigate whether any efficiency gains obtained [from the optimal policy] would be worth the additional complexity."[29]

The LBL approach is attractive because it symmetrically rewards high reliability (and thus low costs) and penalizes low reliability (and the associated high costs). The auction format also enables DOE to make an informed choice between a variety of projects. Despite these desirable attributes, the report's applicability to technology adoption by utilities is somewhat limited. The LBL auction is designed for the allocation of government subsidy funds to commercialization projects. Such projects are intended to generate better knowledge of the performance and cost of CCTs, so as to pave the way for adoption of CCTs by utilities. The auction process cannot be directly transferred to the regulation of electric utilities, however. For example, unlike the bidders in the LBL study, utilities generally do not finance their new generation using highly leveraged financing; thus a lump-sum subsidy may not be necessary. In addition, even in principle regulators in the United States cannot tax or subsidize the firms they regulate, so the

[28] The lump-sum subsidy is required because the projects are assumed to be 100 percent debt-financed and face credit rationing by lenders.

[29] Ed Kahn and S. Stoft, "Designing a Performance Based Cost-Sharing System for the Clean Coal Technology Program," Report LBL-280057 (Berkeley, CA: Lawrence Berkeley Laboratory, Applied Science Division, University of California, September 1989), 14.

lump-sum subsidy proposed by LBL cannot be implemented by state regulators. Thus, although the fundamental ideas of basing rewards on performance and using a cost-sharing mechanism are transferable to the utility setting, the mechanics of the LBL auction are not. The attractive features of the LBL incentive system, however, should be given serious consideration by state commissions for the development of regulatory incentives to promote IGTs.

Argonne National Laboratory

The Argonne National Laboratory (ANL) has also studied regulatory barriers and incentives for the adoption of innovative technologies. ANL proposes two regulatory reforms which, because they do not involve direct subsidy payments, can be implemented by state regulators:

- A sliding-scale mechanism to reward the utility for operating a new plant with a high capacity factor.
- Cost sharing to spread the risks of construction cost overruns, with 50 percent of the overrun absorbed by the utility and 50 percent passed through to consumers.

As discussed above, such sharing systems have been examined in the economic literature, and can have good incentive properties. The ANL proposals also have the virtue that they are symmetric, rewarding good performance while penalizing poor performance. Both of these proposals are partial incentives systems that focus on specific performance measures. Such systems may bias the firm toward focusing cost-reducing efforts on these measures, to the possible neglect of other dimensions of corporate performance.[30] In addition, there is no particular economic efficiency

[30] This problem would seemingly not apply to incentives provided by a utility to nonutility generators (NUGs). This is because NUGs operate in competitive markets whereby increased costs in nontargeted areas could not be passed through to utilities or other purchasers in the form of higher prices.

rationale for a 50-50 sharing rule on cost overruns, though it is attractive from a "fairness" perspective. (Schmalensee[31] finds that the optimal sharing rule can range from 100-0 to 0-100, depending on the firm's environment, the regulator's objectives and the degree of uncertainty about future cost savings.)

Summary

The LBL and ANL studies offer promising ideas for regulatory reform. Both propose a sharing of the risks and benefits of adopting new technologies. Furthermore, the proposed sharing rules are symmetric, allowing the adopter to profit from exceptional performance as well as to suffer from poor performance.[32] Both, however, would reward high capacity factors directly, rather than rewarding more comprehensive measures of operating cost; in addition, the LBL auction could not be implemented by regulators and its lump-sum subsidy may be inappropriate for utilities not financed primarily with debt.

A Selected Broad-Based Incentive System

Description

This section builds upon the preceding discussion and a suggests a package of regulatory reforms aimed at ensuring that regulated firms are not biased against innovative technologies. Two factors are stressed: (1) symmetric treatment of gains and losses, and (2) the use of comprehensive rather than partial incentive systems to the extent possible.

[31] Schmalensee, "Good Regulatory Regimes."

[32] As discussed in Chapter 6, however, comprehensive incentive systems may be more appropriate in a competitive environment.

Several authors have recently proposed comprehensive, symmetric, regulatory systems built on the principles of incentive regulation discussed above. These proposals combine elements of price caps and profit sharing (and, in some cases, yardstick competition as well) in a dynamic framework with a lengthened regulatory lag. While these systems have not been developed specifically for the electric power industry, their basic principles apply here as well.[33] This section adapts these ideas to create a proposal for use in the electric power setting. The proposal overcomes the three key problems identified earlier in this report: too short a period of regulatory lag, distortionary upper and lower bounds on earnings, and the use of hindsight review.

Figure 7-3 shows the timing of the various components of the plan. The regulator initiates the system by aggregating the utility's various service offerings into a small number of groups (often called "baskets") of services, and setting a total revenue cap R_0 for each basket; the regulator also sets a fixed regulatory lag period, which will typically be considerably longer than under rate-of- return regulation. During each of the next periods until a full rate review is held, the total revenue cap is adjusted simply by applying an index formula that is outside the firm's control; for example, the caps might
be allowed to rise with the consumer price index (CPI) less some adjustment for expected technological progress (X). Finally, at the next full rate review, the firm's new set of prices p_t+1 is constrained so that total revenues (using the new prices and the previous period's quantities) are less than the previous period's revenues by an amount reflecting consumers' share of the firm's previous period above-normal profits.[34]

[33] See, for example, Lorenzo Brown, Michael Einhorn, and Ingo Vogelsang, "Toward Improved and Practical Incentive Regulation," *Journal of Regulatory Economics*, 3 (1991), 323-38; and Thomas Lyon and Michael A. Toman, "Designing Price Caps for Natural Gas Distribution Companies," *Journal of Regulatory Economics* 3, no. 2 (June 1991), 175-92.

[34] In effect, the mechanism takes away a portion of the firm's excess profits earned in a particular period and gives it to consumers in a later period. Symmetrically, the mechanism holds consumers responsible for a portion of the insufficient profits (that is, profits below normal levels) earned in a previous period.

Fig. 7-3. Sequence of events in proposed regulatory process.

The proposed system features several key elements:

- Rates would be set for each of a few "baskets" of the utility's services, rather than for each service individually. A utility's tariff schedule typically contains a large number of different prices reflecting different services (connection charges, capacity charges, energy charges--possibly differentiated on a time-of-day basis) and different customer classes (for example, residential, commercial, and industrial). Rather than setting a separate price cap for each possible item, a number of service offering/customer class combinations would be grouped together, and a cap on the total revenue for the group of services would be set.[35]
- Full review of the revenue caps on each basket would occur at relatively infrequent intervals (for example, every three to five years). A five-year review, for example, may be warranted if a major goal is to elicit capital-intensive productive improvements.
- Between rate reviews, the revenue cap for each basket would be indexed to reflect changing cost conditions and expectations of technological progress. The index would be similar to the CPI - X (consumer price index - expected rate of technological progress) formula pioneered in the United Kingdom, so that the revenue cap for each basket in period t + 1 would be $R_{t+1} = R_t(1 + CPI - X)$.[36]

[35] Placing a separate price cap for each customer would mitigate against politically intolerable price discrimination. The potential pricing-efficiency gains, however, would not be as great.

[36] After further study of alternative index measures, it might be preferable to replace CPI with a measure tailored to cost conditions in the electric utility sector (for example, a measure based on a regional electric industry cost index). Such an index should better track cost changes for an individual utility. This would likely cause the utility's profits to fluctuate less from normal profits, and prices would deviate less from the utility's actual costs.

- At each full rate review, say every five years, the revenue caps would be updated using the constraint that $p_{t+1}q_t \leq p_t q_t - (1 - \alpha)\prod_t$, where $\prod_t$ equals $\sum_s^t\ [p_s q_s - C_s](1 + r)^{t-s}$, where p_t and q_t are vectors of the firm's prices and quantities in period t, C_t is the firm's total cost in period t, r is the discount rate, and $(1 - \alpha)$ is the customers' share of last period's earnings. Thus, if consumers were to purchase the same bundle of services as in the previous period, they would receive a rebate of at least "their share," $(1 - \alpha)$, of the firm's (properly discounted) total net earnings since the last rate review.[37] Note that if $\alpha = 0$, then the adjustment procedure is similar to rate-of-return regulation, but with the firm given greater pricing flexibility with respect to the prices of individual services; if $\alpha = 1$, then the procedure is a pure revenue cap. In practice, state implementation of profit-sharing plans has often included the provision that if the firm's earnings are within a "deadband" of specified width then the firm retains all earnings; sharing is only triggered if earnings are outside the deadband. The simulation analysis of the next section includes a deadband.

These elements combine to produce a number of desirable effects. Because the plan is a comprehensive,[38] rather than a partial, incentive system, there is no built-in bias toward excessive use of any particular inputs. Furthermore, symmetric sharing of gains and losses avoids biasing the firm's attitude toward risk. Individual components of the plan also have their own specific effects:

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[37] This "ratcheting" procedure is suggested in both Lyon and Toman, "Designing Price Caps"; and Brown, Einhorn, and Vogelsang, "Toward Improved and Practical Incentive Regulation."

[38] It is assumed up to this point in the discussion that all utility costs would be incorporated into the incentive plan. Treatment of new plant costs, fuel costs, and purchased power in practice may, however, be done outside the comprehensive incentive plan presented here (see later discussion in this chapter).

1. the use of caps on baskets of services (rather than on individual services) gives utilities greater pricing flexibility than under traditional regulation while still constraining total revenues; this flexibility improves the firm's ability to respond to changes in the economic environment without triggering a costly rate review;
2. increased regulatory lag between full reviews gives the firm greater incentive to invest in cost-reducing innovations;
3. indexing rates between rate reviews stabilizes the mechanism by reducing the chance that excessive gains or losses will accrue during the lag period; and
4. over time, the procedure applied at full rate reviews "ratchets" the firm toward Ramsey pricing, the well-known pricing formula for maximizing welfare subject to ensuring that the firm breaks even.[39]

Finally, profit sharing (that is, $\alpha < 1$) tempers the incentive features of pure revenue caps, speeding the convergence of prices toward costs. (This reduces the risk of a cap that is set too high or too low, and enhances the perceived fairness of the plan.)[40] Regulators face a tradeoff in dealing with input costs. On the one hand, passing input costs directly through to customers alleviates financial pressures on the firm, reduces the need for full-scale rate reviews, and helps reduce the administrative costs of regulation. On the other hand, the use of pass throughs such as fuel adjustment clauses blunts any incentive the utility may have to hold down its input costs. The key question in deciding whether to use a pass through is the extent to which the utility can control the cost of the input in question.

Three inputs of great concern to utilities are fuel, purchased power, and new plant. All of these, to some degree, are within the control of the firm, so a pure passthrough may have poor incentive effects. One alternative that is consistent with the proposal presented here is to tie the utility's compensation on these dimensions to an index that is beyond the firm's control, as in the

[39] For a discussion of convergence to Ramsey pricing, see Ingo Vogelsang, "Price Cap Regulation for Telecommunications Services: A Long-Run Approach," in Michael Crew, ed., *Deregulation and Diversification of Utilities* (Boston: Kluwer Academic Publishers, 1989).

[40] This issue is discussed further below.

use of yardstick regulation. For example, this can be done by replacing the CPI - X index with one that is specifically tailored to the cost structure of electric utilities.[41] A second approach is to replace the traditional automatic adjustment clause (AAC) with a "fixed-weight" AAC, as proposed in Burns, Eifert, and Nagler.[42] This approach involves the use of a price adjustment mechanism similar to that proposed above, but applied to inputs instead of outputs. Price adjustment mechanisms for inputs and outputs can readily be combined, as in shown in Vogelsang.[43] In order to ensure the utility has incentives to hold down the cost of fuel and purchased power (other than abolishing the AAC), either the index or the fixed-weight AAC for these inputs should be incorporated as part of the present proposal, rather than a pure passthrough.

The treatment of new capital investment in large generating plants is particularly difficult, given the huge sums involved and the difficulties in measuring a firm's cost of capital. Hindsight reviews based on *ex post* notions of prudence (as discussed in Chapter 4) clearly need to be replaced with a more comprehensive and symmetric mechanism. The proposed plan would supersede hindsight review, although egregious instances of fraud or mismanagement (as under traditional review of prudent management) could be punished without undermining the firm's incentives to invest. The difficulty for regulators is that if replacement costs are above current average costs, then the firm's

[41] This approach has been applied to some New York electric utilities. Yardstick regulation has the advantage of replicating competitive markets by allowing a utility to earn above-normal profits if it is able to outperform other firms in the same industry.

[42] Burns, Eifert, and Nagler, *Current PGA and FAC Practices*.

[43] Vogelsang, "Price Cap Regulation for Telecommunications Services."

revenues must increase when new plants are built.[44] While this can in theory be accomplished through indexing or some variant of an AAC, the most direct approach is to hold a special rate hearing when a plant comes on line to increase the total revenues the firm is allowed to collect. The regulator must either evaluate the prudence of the costs incurred or employ some sort of indexation or partial incentive plan for construction costs. Given the historical problems with *ex post* review of construction costs, one promising index involves the application of yardstick competition using the construction costs of comparable projects. (This, of course, presumes that the regulator can employ on-site inspection to ensure that cost savings do not come at the expense of quality of construction.)[45] A successful yardstick system requires developing a database of construction costs for plants from other jurisdictions, and, in the interests of fairness, using econometric techniques to compensate for the effects of cost "drivers" that are outside the utility's control, such as regional wage rates and taxes. The estimated cost, rather than the actual cost of the comparison firms, would be used in developing the utility's new revenue requirement.

As another alternative to controlling the cost of new capacity, a commission may sanction a straight competitive bidding mechanism. This would allow a third party to judge the bids, pay the utility its bid price if it is the winner, and perhaps include some sweeteners for IGTs regardless of who builds.

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[44] This condition would not hold if a utility expects to be a decreasing-cost firm in the future. It is likely that for some electric utilities their average costs will decline with the acquisition of additional resources over the next several years. If so, new capital expenditures could become part of the "CPI-X" formula without jeopardizing the financial position of the utility.

[45] The yardstick approach is discussed in Joskow and Schmalensee, "Incentive Regulation for Electric Utilities." An alternative, but more complex, approach is for the regulator to allow the firm to choose from a menu of cost targets and cost-sharing rules. If the firm were confident of its ability to control costs, it could select a lower cost target and take full responsibility for cost overruns, keeping any savings itself; if not, the firm could select a higher cost target but keep a lesser share of any savings below the target. This approach is presented in Laffont and Tirole, *A Theory of Incentives*.

The reforms described above remove the regulatory disincentives to innovation identified earlier in this report. Because they create a comprehensive, rather than a partial, incentive system, there is no built-in bias toward excessive use of any particular inputs. Symmetric sharing of gains and losses avoids biasing the firm's attitude toward risk. Finally, the proposal does not require government to undertake the difficult task of picking technological winners; instead it leaves this decision to the firm, with its superior information about the prospects for successful adoption of individual technologies.

Numerical Simulation

One of the key components of the proposal outlined above is the use of profit sharing at full rate reviews. This sharing feature of the plan is consistent both with the general principles of incentive regulation outlined above and the partial incentive systems proposed by LBL and ANL. An earlier chapter presented the results of a simulation analysis that showed how regulatory hindsight reviews reduce a firm's incentives to adopt IGTs. This section extends that analysis to study how profit sharing affects the firm's incentives to innovate.

It should be recognized that the simulation represents a simplification of the full proposal described above. The firm is assumed to produce a single product, so there is no need to define service baskets. The analysis is conducted in terms of real prices and costs, so there is no need to consider inflation adjustments. The focus is thus directly on the firm's choice between an IGT and a conventional generation technology (CGT). The riskiness of the IGT is represented solely by the uncertainty of its construction costs; in practice, of course, a variety of other performance features such as plant reliability are important as well.

In this analysis, the regulator sets an initial price cap p_0, and the firm then chooses a technology (either a conventional one with fixed construction costs c_f per MW, or an innovative one with expected construction costs c_s) and a level of capital investment K. The plant is constructed, construction costs are realized, and a new rate review is held. If the firm's return on capital is within a specified "deadband," then the firm is allowed to keep all of its net earnings; any earnings outside the deadband are shared between the firm and customers, with the firm retaining a fraction α of any excess earnings. Let $R(p_0)$ be the firm's revenue when the price is p_0, w be the price of variable inputs, and $L(p_0,K)$ be the firm's variable input requirements when it chooses a capital stock K. In addition, let c be the firm's cost of physical capital (this is fixed at c_f for the conventional plant, or stochastic with realization c_s for the innovative technology). The cost of financial capital is r, and the upper end of the deadband is denoted by rate-of-return s. Thus, with profit sharing, the firm's effective rate-of-return constraint is

$$R(p_0) - wL(p_0,K) \leq scK + \alpha[R(p_0) - wL(p_0,K) - scK]. \tag{7-2}$$

Equivalently, the firm's realized profits can be expressed as

$$\pi(c) = [1 - \alpha](s - r)cK + \alpha[R(p_0) - wL(p_0,K) - rcK]. \tag{7-3}$$

Thus, when $\alpha = 1$ the firm keeps all earnings at the given price level, while if $\alpha = 0$ all earnings outside the deadband are returned to consumers. When the firm chooses an innovative technology, there is the possibility that construction costs come in so high that earnings fall below the deadband. In this case, profit sharing leaves the firm with profits of $\alpha[R(p_0) - wL(p_0,K) - rcK]$.

For simulation purposes, the key variables of interest are α, the degree of profit sharing; p_0, the initial price cap; and c_f and c_s, the respective expected costs of the conventional and innovative technologies. The results reported below assume that the IGT has lower expected costs ($1 billion per MW) than the conventional technology ($1.2 billion per MW), but higher variance. Two different initial price levels are examined, and a range of values of α is considered in each case. The key result in these calculations is the extent of profit sharing required to level the playing field between the two technologies. Representative results are presented in Table 7-1, and exhibited graphically in Figures 7-4 through 7-7.

TABLE 7-1

Profit Sharing and Innovation

Expected Cost of Innovative Technology = 1

	P0 = 7 Cf = 1.2				P0 = 5, Cf = 1.2			
	Conventional		Innovative		Conventional		Innovative	
Alpha	K*	Profits	K*	Profits	K*	Profits	K*	Profits
0	1138.9	$68.3	933.2	$32.6	1034.8	$21.9	1185.5	$18.0
0.1	1138.9	$68.3	933.2	$39.2	1034.8	$21.9	1169.7	$20.4
0.2	1138.9	$68.3	933.2	$45.7	1034.8	$21.9	1126.3	$22.8
0.3	1138.9	$68.3	933.2	$52.2	1034.8	$21.9	1113.3	$25.3
0.4	1138.9	$68.3	932.4	$58.7	1034.8	$21.9	1104.6	$27.9
0.5	1056.1	$74.0	932.4	$65.3	1034.8	$21.9	1099.2	$30.4
0.6	982.8	$77.7	932.4	$71.8	1034.8	$21.9	1095.1	$32.9
0.7	943.3	$79.0	931.5	$78.3	1034.8	$21.9	1091	$35.5
0.8	918.2	$79.5	931.5	$84.9	1034.8	$21.9	1087.1	$38.0
0.9	900.8	$79.7	930.7	$91.4	1034.8	$21.9	1084.9	$40.5
1	888.1	$79.8	929.3	$97.9	1034.8	$21.9	1083.4	$43.1

Figures 7-4 and 7-5 represent a case with a relatively high initial price of $0.07 per kilowatthour (kWh). Figure 7-4 shows that even though the IGT has lower expected costs, the bias toward the CGT is not overcome in this example until the firm's share of excess earnings reaches 70 percent. To understand this result, consider Figure 7-5 and the firm's choice of capacity for a CGT. When $\alpha = 0$, the firm choosing a CGT will size it so as to earn the maximum allowable return s on its capital. Because the rate-of-return constraint s is binding, the firm overcapitalizes. By reducing its capital stock, the firm can increase its earnings, but unless it captures a substantial share of this increase, the firm has no incentive to cut back its capital stock. Figure 7-5 shows that the critical level of α is 0.4; for $\alpha > .4$, the firm has reduced incentives to overcapitalize. As the firm's share of earnings rises beyond this point, its profits increase as it chooses a more efficient and less capital-intensive plant; this can be seen in Figure 7-4. Consider now the firm's capacity choice with an IGT. The level of capacity for the IGT is very insensitive to changes in α in this case; profits from the innovative technology, however, rise smoothly with the firm's share of excess earnings. For $\alpha > 0.7$, the firm selects the IGT because of its greater profitability.

Figures 7-6 and 7-7 present a case with a lower initial price of $0.05 per kWh. Figure 7-6 shows that the profits from the IGT again increase smoothly with increases in α, and that for $\alpha \geq 0.2$, the bias against the IGT is eliminated. When the initial price is $0.05 per kWh, profits from the CGT are completely unaffected by increase in α, in contrast with the results in Figure 7-4. The reason is that at the lower price cap, and with the high cost of the CGT, the firm never hits the rate-of-return constraint, so it does not benefit from being entitled to a higher share of earnings outside the deadband. Relatedly, it has no incentive to overcapitalize on the CGT, even when $\alpha = 0$. On the other hand, Figure 7-7 shows that the capacity of the IGT, if it is selected, declines as α rises. Even with the low price cap, the earnings constraint may become binding if IGT costs turn out low enough; thus, the firm has some incentive to overcapitalize the IGT, but this incentive is weakened as α rises.

These two different sets of simulation results indicate that profit sharing can indeed be a useful means of leveling the playing field between innovative and

Fig. 7-4. Firm's total profits: case 1.

Fig. 7-5. Firm's capacity choice: case 1.

Fig. 7-6. Firm's total profits: case 2.

Fig. 7-7. Firm's capacity choice: case 2.

conventional technologies. There is always some level of profit sharing beyond which the bias against the IGT is overcome, and for which the firm selects the cost-minimizing technology. For example, a pure price cap corresponds to $\alpha = 1$, and induces the firm to minimize costs and choose the cheaper technology. As discussed earlier, however, pure price caps are rarely optimal. The simulation shows that the minimum α required to level the playing field may vary substantially with the initial price cap chosen by the regulator. A tight price cap reduces the attractiveness of the conventional technology, which means a relatively small α will be enough to induce the firm to select the IGT. When the initial cap is higher, building an oversized conventional plant is very profitable, and a large α is required to overcome the bias against the IGT.

In linking the above results to the incentive-mechanism proposal, it is important to remember that regulators always face a tradeoff between extracting the firm's rents and ensuring the firm's viability. A low price cap poses a greater risk of negative earnings for the firm, and may create pressures to undo regulatory reform unless some of that risk is shared with customers via a relatively low α. Fortunately, the simulation results suggest that in this situation, a low α may be sufficient to level the playing field
between IGTs and CGTs. If a high price cap is set instead, a level playing field may require something close to a pure price cap (very large α), leaving substantial rents to the firm. This suggests that a fairly tight price cap combined with a sharing rule weighted toward consumers (low α) may be the best policy.

To recapitulate up to this point in Chapter 7, the disincentives to innovation created by traditional rate-of-return regulation and retrospective hindsight reviews can be overcome through reform of state regulatory practices. The reforms proposed here include capping total revenues on one or more "baskets" of services provided by the utility, increasing the regulatory lag between full rate reviews, indexing the revenue caps between rate reviews, and using a profit-sharing rule at full rate reviews. These changes enhance the firm's incentives to invest in cost-reducing innovations, and because they feature symmetric sharing of gains and losses they avoid biasing the firm's attitude toward risk. In addition, the proposed changes give utilities greater pricing flexibility, continue to constrain total revenue requirements, and guide the firm toward Ramsey pricing over time.

The proposal presented here is not based on compensating for environmental or informational externalities. As argued above, environmental externalities offer at best a weak justification for selective subsidy of particular technologies. Basic economic principles suggest that direct internalization of environmental costs--through emissions markets or through Pigouvian taxes--is a preferable way to correct environmental problems. Informational externalities, on the other hand, offer a rationale for federal and perhaps state government subsidy of a small number of innovative technology applications by utilities. The federal government recently reaffirmed this role for itself in the Energy Policy Act of 1992. This, of course, is still a separate program from the reform of state public utility regulation.

Can regulators credibly commit to the proposals laid out above or, for that matter, to *any* new proposals? At the most general level, the answer seems to be "Not really." A given utility regulatory commission simply cannot prevent future commissions from undoing its handiwork. Nevertheless, in practice there is usually considerable continuity in regulatory practice. The increased use of integrated resource planning, which involves regulators more closely in the utility planning process, may reduce the likelihood that regulators will engage in retrospective review of plants that were prudent at the time they were built.[46]

If such regulatory commitments cannot be made, the likely effect will be to push the electric power industry toward a world where most of the new generation is done by unregulated NUGs and utilities provide transmission, distribution and system coordination. This outcome is not unlikely, in any event, especially in light of the amendments to the Public Utility Holding Company Act (PUHCA) that were included in the Energy Policy Act of 1992.[47] And the enhanced generating unit competition that would result might make for an industry structure that

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[46] A commission could rightly accept both the proposed incentive system and integrated resource planning (IRP) at the same time. In a competitive environment, where the incentive system would be most potentially beneficial, however, IRP would likely have to take on a different form than what exists currently. For example, utilities would need to have more flexibility, and subsidies for demand-side management activities may be difficult to fund.

[47] For a summary of the Energy Policy Act, see Kenneth W. Costello et al., *A Synopsis of the Energy Policy Act of 1992: New Tasks for State Public Utility Commissions* (Columbus, OH: The National Regulatory Research Institute, 1993).

is preferable to one with more vertical integration. Nevertheless, it seems desirable to implement regulations that give utilities incentives to adopt IGTs when this is the least-cost means of producing power.

Selected Partial Incentive System:
Cost Sharing of Life Cycle Costs

The following sections present and illustrate a partial incentive system based on the life-cycle costs of a technology with targeted attributes. The system is partial in the sense that it is designed to meet performance and cost objectives for a single facility or group of facilities rather than the whole utility system. The system, however, is more comprehensive than most partial systems in that it does not target a single performance attribute, such as construction costs or operating availability of a facility. Rather, it uses a composite target of maximizing both construction and operating performance over the life of a facility.

Concept

The selected incentive system is applicable when a utility needs new capacity and is considering the choice between a CGT and an IGT to meet this capacity.

It has four basic objectives. First, it seeks to reduce the financial and performance risks during the construction period and the initial years of operation of an IGT. Second, the system also seeks to allow the utility to gain, and thereby make profits in excess of the allowed rate of return, from any potential savings over the life-cycle costs of the facility. Third, the system allows the ratepayers to enjoy a share of the savings. Finally, the system seeks to achieve the three listed objectives at the least cost. The four objectives outlined above presumes that although an IGT would likely be more risky and more expensive than a conventional alternative during the construction and the initial operating period, it would likely be a better performer and cheaper over its life cycle. This presumption is inherent to the rationale for promoting the commercial adoption of an IGT.

The conceptual design of the incentive system consists of a number of steps. First, a conventional technology with relatively well-known and predictable cost and performance attributes is chosen as a bench mark. For example, if a utility's forecasts indicate the need for building a large base-load plant, a conventional pulverized coal plant (equipped with a conventional scrubber for pollution control) of the intended capacity can be chosen as a bench mark. Second, the life cycle costs of the bench-mark plant are either estimated or an indexing method is established to estimate the costs on a current basis. These costs are to be discounted to a base year to determine their total present worth. Third, a technology with the desired performance and cost attributes is chosen. Performance attributes may include expected heat rates or energy conversion efficiencies, emission of pollutants such as SO_2, NO_x, CO_2 and solid and liquid wastes. Cost attributes may include the expected construction cost, operating costs during earlier years and expected mature operating costs during later years. While the choice of the candidate plant is a decision to be made by the utility, screening by performance and cost attributes provides the public utility commission a means to ensure that the most promising IGT is chosen for the incentive. The final step in the incentive system consists of establishing the sharing rule between utility shareholders and ratepayers to allocate cost savings or cost overruns based on a comparison of the life cycle costs of the candidate IGT and the conventional bench-mark technology.

The incentive is intended to be voluntary: the choice of technology and the choice of parameters are to be proposed by the utility and to be approved by the commission after regulatory review and opportunity for intervention by other parties. The incentive system can be combined with other incentive concepts such as prudent abandonment rules, preapproved construction cap, and capacity utilization bonuses. Therefore, the proposed incentive system is generic and inclusive of several partial incentive concepts. An examination of the proposed system can provide insights into the efficacy of the partial incentive concepts.

Mathematical Development

Basic Model

Assume that the bench-mark technology (BT) has a construction period of P_b and an operating life of L_b; the expected construction period for the candidate IGT is P_i and the expected operating life is L_i; also assume that the total present value of life cycle costs (PVRR) of the bench-mark technology is T_b, of which the capital cost (construction cost plus carrying charges) is K_b and the operating cost is O_b. The corresponding cost parameters for the IGT are T_i, K_i and O_i. The relationships between various quantities are indicated in the following equations.

$$T_b = K_b + O_b \tag{7-4}$$

where T_b: present value of the life-cycle costs of the BT

K_b: present value of the capital costs of the BT

O_b: present value of the operating costs of the BT

$$T_i = K_i + O_i \tag{7-5}$$

where T_i: present value of the life-cycle costs of the IGT

K_i: present value of the capital costs of the IGT

O_i: present value of the operating costs of the IGT

Assume that the revenue to be collected from ratepayers is T_r. Then, T_r is given by,

$$T_r = T_b + x_t(T_i - T_b) \tag{7-6}$$

where x_t equals ratepayers' share of cost savings or cost overruns.

Determining Annual Sharing Rule

Given the sharing rule specified in equation (7-6) for the present value of life cycle costs, one then needs to develop a sharing rule that would apply to the recovery of costs for each year of the facility. The sharing rule would be intended to drive the cumulative sharing fraction closer to the target sharing fraction x_t. The cumulative sharing fraction x_{tc} is related to the annual sharing fraction, x_{tk} by

$$\sum_{k=1}^{n} T_{bk} + x_{tc} \sum_{k=1}^{n} (T_{ik} - T_{bk}) = \sum_{k=1}^{n} T_{bk} + \sum_{k=1}^{n} x_{tk}(T_{ik} - T_{bk})$$

which leads to x_{tc} =

$$x_{tc} = \sum_{k=1}^{n} x_{tk} (T_{ik} - T_{bk}) / \sum_{k=1}^{n} (T_{ik} - T_{bk}) \tag{7-7}$$

where x_{tk}: sharing fraction for year k

T_{ik}: cost of IGT for year k

T_{bk}: cost of BT for year k

n: current year

If the commission so chooses, the utility may be allowed to specify relatively high sharing fractions during the first few years of operation, when the risk of operating performance is at its greatest. In fact, the utility may choose a sharing fraction of 1, which makes the recovery principle similar to a cost-plus arrangement. Once this initial period is over, however, the updating rule discussed in preceding sections governs the recovery of costs.

The above specification of sharing fraction forces the utility to choose a technology, and manage its construction, financing and operation in a manner such that the related revenues to be borne by ratepayers are either close or less than those for a conventional substitute. If the utility is successful in achieving the purpose of this incentive system, the utility may earn higher profits than under traditional regulatory treatments.

Choosing the Bench-Mark Technology

One of the most difficult tasks of developing the currently discussed incentive system, and any other such system for that matter, is choosing a method and the appropriate data for establishing the cost and other parameters for the bench-mark technology. The choice is particularly complicated by the problem of defining the bench-mark technology. The bench-mark technology, by implication, must be one with known performance attributes and history. Therefore, it would be reasonable to choose as a bench mark any generation technology with a well-known performance record. For base load plants, conventional pulverized coal-fired plants and light water reactor (LWR) plants suggest themselves as bench-mark technologies. The performance record of both of these technologies, however, may vary by design, size and utility. Therefore, the specification of bench-mark parameters requires a specification of design and size, and a decision on whether a utility-specific or a broader domain should be used to establish such specifications.

The decision about design and size specifications may not be too difficult. It is reasonable to use those sizes and designs that have been historically applied by the utility. For example, for a utility using coal-based generation with high sulphur coal, a pulverized coal with a scrubber (PC/FGD) would be an appropriate choice for a bench-mark technology. Once a specified design and size are chosen, the cost and performance parameters need to be chosen next. Here, the choice between utility-specific and more broad-based parameters is more difficult: each choice has its own merits and drawbacks.

The performance of a technology may depend on utility-specific factors in two different ways. It certainly depends on the quality of technical and administrative management. It also depends on other factors, such as transportation access to fuel markets and fuel transportation costs, that are not entirely within a utility's control and yet are still utility specific. To the extent the performance of a technology depends on the utility's own quality of management, it makes more sense to use a bench mark based on a broader universe of performance history than the utility's own. For example, the performance record of the bench-mark technology for all utility's in a state or the country may be used to derive bench-mark parameters. At the same time, care must be taken to make sure that "oranges" are not being compared to "apples," especially when doing so may unduly penalize or reward the utility. For example, if the technology has done better with other utilities than the target utility not because of any differences in managerial efficiency but because of differences in such factors as transportation access to fuel supplies, using a broad-based yardstick may unduly penalize the utility. The reverse may be true if the technology has done better under the target utility's management because of special advantages available to the utility. On the other hand, no reason exists to choose a bench mark based on the performance of a technology owned by a poorly managed utility.

The choice of a domain for deriving the bench-mark parameters, therefore, may require a careful examination of all factors that contribute to a technology's performance with special distinction being made between endogenous and exogenous factors. Clearly, the choice will likely be different for individual utilities and will depend on the needs and policy preferences of individual commissions. Also, it is possible to make adjustments for the appropriate factors once the domain has been chosen to derive bench-mark parameters. For example, if no significant differences among utilities in a given jurisdiction exist except for transportation access to fuel supplies, the commission may choose a yardstick bench mark based on all utilities (except the target utility) and make an specific adjustment for the transportation costs.

Choosing Bench-Mark Parameters

Once the domain has been chosen for deriving bench-mark parameters, the next step is to chose a method to derive the bench-mark parameters. The goal is to come up with an "average" set of parameters based on some "average" standard. One of several methods is available for determining average parameters. One can either choose the parameter associated with the "average" performer or the weighted average value of the parameter for all plants.

For example, if the sample population of, say, ten plants has heat rates varying between 8,500 Btu per kWh and 9,500 Btu per kWh, and the average performer is the plant with the median value, say, 8,950 Btu per kWh, then the bench-mark heat rate becomes 8,950 Btu per kWh. On the other hand, one could use the average heat rate of the plants in the sample, weighted by total generation in a specified period as the bench mark. This bench mark incorporates the effect of forced and scheduled outages (and therefore the capacity factor) and may be more objective than the first bench mark. Similar derivations of bench-mark values can be performed for such parameters as forced outage rates, capacity factors, construction time and costs, and operating costs.

Projecting Future Values of Bench-Mark Parameters

The set of bench-mark values discussed above constitutes baseline values, or values for a chosen base year. Next, one needs a method to determine values of these parameters in a future year. Two possible methods come to mind. The first method would attempt to forecast parameter values and the second would index them. It is to be noted that some parameter values, particularly those related to performance, may not change significantly for mature, bench-mark technologies. For example, one expects very little change in the forced outage rate or heat rate for a conventional pulverized coal-fired plant.

The parameters most likely to change are cost parameters that are subject to changes in inflation and interest rates, changes in the market prices of fuel, labor, equipment and other inputs. To determine future values of cost parameters, one can use forecasting tools such as time series or trending analysis or choose a set of indices that adjust values on a current basis. Among the two, indexing is a more objective method, as it would yield values that are closer to the actual costs of the bench-mark technology.

Determining the Sharing Fraction

The sharing fraction, x_t, may be difficult to determine. As one alternative, the commission and the utility may mutually agree on a value. If x_t is 0, then the incentive becomes a fixed cost contract and the utility recovers no more (or less) than the bench-mark cost. If x_t is 1, then the utility recovers all the actual costs and the incentive becomes a cost-plus contract. At any other value, the risks and gains are shared between the utility and the ratepayers. Choosing a high value (closer to 1) for x would shift more of the risks and a higher share of the gains to the ratepayers. If the utility is risk averse or if it lacks confidence in the economic performance of the technology, it may prefer a high sharing fraction. If a commission agrees to a high sharing fraction, however, it defeats one of the purposes of the incentive, namely, to reduce risks to ratepayers and increase opportunities for augmenting a utility's earnings through adoption of a economically promising IGT. If the utility itself does not have much faith in the promise of the IGT, little reason exists in the first place for introducing special incentives to facilitate its adoption.

The above observation leads to a potentially effective approach in determining the sharing fraction. The commission can use the utility's choice of the sharing fraction as a confidence revelation mechanism. The commission may ask the utility to propose sharing fractions for different candidate IGTs. The lower the sharing fraction chosen, the higher the confidence level of the utility in controlling the costs of the proposed IGT. The commission then may choose one or more IGTs for incentive treatment that have the lowest sharing fractions. If all the proposed sharing fractions are higher than a prespecified value (say, 80 percent), the commission may conclude that none of the proposed IGTs have reached precommercial readiness: further development through demonstrations is required (perhaps to be supported by appropriate federal and state incentives) and consequently additional rate-making incentives are not warranted. This approach to setting the sharing fraction is consistent with the basic rationale that regulatory incentives are intended to remove uneconomical or inefficient barriers to adoption of IGTs, rather than intended to support adoption of IGTs that do not meet the appropriate economic tests. One such test is that the adopter has a reasonable expectation that in the long run the chosen IGT will perform better economically than the conventional alternative.

Difficulties and Possible Solutions

The above rationale and analysis may not account for some difficulties, especially with regard to precommercial plants. It can be argued that the first commercial application of an IGT may perform worse than a conventional alternative even in the long run (over its life cycle). What needs to be evaluated, this argument would say, is the mature technology costs of the IGT after its third or fourth commercial application. The appropriate comparison, therefore, should be between mature technology costs of the IGT and the corresponding costs of the conventional technology. If society is likely to benefit in the long run by commercially deploying four or five applications of an IGT rather than continuing to use a conventional technology, it can be argued that it certainly should do so by providing appropriate incentives.

A first approach would be to limit the commission incentive to a certain level and encourage the utility to obtain any needed additional support from other public agencies or institutions. Currently, for example, the Ohio Commission allows an automatic passthrough of the utility portion of the demonstration costs of a PFBC plant, which is cofunded by the U.S. Department of Energy and the Ohio Coal Development Office. An analogous treatment can be extended to commercialization of IGTs, with risks and costs being shared between ratepayers, the utility and a federal agency such as the DOE. A second approach that can be used in conjunction with the incentive is the pooling of investments for commercializing an IGT. If several utilities agree to share the investment in an IGT plant, the risks of cost overruns and the utility share of such risks can be spread over several utilities.[48] The gains, achieved through the incentive system are similarly shared. Although this arrangement may weaken the potential gains

[48] There would still be the problem of assigning to the various utilities the control of plant construction and operation.

from a successful project, it considerably reduces risk consequences of a failed project to an individual utility. This kind of incentive can work particularly well for utilities within the same commission jurisdiction, so that sharing of gains or losses face uniform treatment through the same incentive system.

A third approach is to apply the incentive to multiple generations of plants using the same innovative technologies. The plants can be built on a staggered schedule so that: (1) information gained and lessons learned from the construction and operation of each plant can be applied to the next plant; and (2) a successively improved performance record can achieved. To be effective, the incentive system should not be changed for successive generation of plants. The reason for this is that losses suffered or gains (relatively small) achieved by the utility in earlier versions of the plant can be offset by successively larger gains to be made from later, more mature versions of the plant. This particular arrangement would only be appropriate if a significant on-going need exists for new capacity to justify building several plants in quick succession. Such a justification may not be needed, however, if several utilities agree to pool investments in each of the plants, although each utility may only require one such plant. In this case, the lessons learned from building and operating one plant in one utility's service area can be used to improve the construction and operation of another plant in another utility's service area. If the utilities fall under more than one commission's jurisdiction, the same approach may still be used if the affected commissions can devise a collaborative arrangement or if the commissions individually agree to the proposed incentive system or a variant of the system.

Numerical Illustration

To illustrate the proposed incentive system, the following sections present and analyze a simple example.

Choosing A Viable Candidate IGT

Assume that a hypothetical utility is considering building a 300 MW coal-fired plant and has the choice between a pulverized coal plant with an FGD (PC/FGD) and several CCTs. The utility is presented with the proposed incentive system with an average performing PC/FGD as the bench-mark technology.

As a first step, the utility attempts to establish a set of parameter values that will make a CCT a viable candidate according to some criteria. For example, assume that the utility decides that for the CCT to be viable, and for the utility to have a reasonable financial advantage in accepting the incentive, the cumulative present value of costs associated with the CCT must match the corresponding value for the BT in twenty years or less. The next step is to perform a break-even analysis for twenty years using projected data for the BT and hypothetical data for the CCT.

Break-Even Analysis

Data Assumptions

Table 7-2 gives the data assumed for the BT and the hypothetical CCT. It is assumed that the CCT will achieve a 15 percent improvement in heat rate over the BT. Although the mature capital cost of the CCT is projected to be comparable to that
of the BT, a certain risk exists that a first generation CCT is likely to incur a higher capital cost than the BT. The goal is to find an upper limit for the capital cost such that the higher capital cost is offset by the cost advantage of the lower heat rate and a break-even cost performance is achieved in twenty years or less.

TABLE 7-2
BASELINE DATA FOR BT AND CCT*

Data	BT	CCT
Capacity	300 MW	300 MW
Capacity Factor	0.65	0.65
Energy Generation	(300,000 kW)(8,760 h/yr.)(0.65 yr.) = 1.708 x 10^9 kWh	1.708 x 10^9 kWh
Heat Rate	10,044 Btu/kWh	(10,044 Btu/kWh)(0.85) = 8,537 Btu/kWh
Unit Fuel Cost	$1.51/million Btu	$1.51/million Btu
Fixed O&M	$30/kW-yr.	$30/kW-yr.
Capital Cost	$1,434/kW	To be determined
Construction Time	4 years	4 years
Construction Start Date	1996	1996
Service Date	2000	2000
Book Life	30 years	30 years
Tax Recovery period	20 years	20 years

* All dollar figures are in 1988 dollars.

There are, however, other risks associated with the CCT, besides the higher capital cost. For example, it is quite likely that the CCT will not achieve the expected 15 percent improvement in heat rate during the first few years of operation. Also, because of higher than expected forced outages, the capacity factor of the CCT is likely to be less than that assumed for the BT during the first few years of operation. Finally, the fixed operating and maintenance costs are also likely to be higher for the CCT than the BT during the first few years of operation. The higher fixed O&M expenses are needed to overcome the capacity-factor problem and to solve other operating problems during the initial operating period.

Therefore, as reflected in Table 7-3, some additional data assumptions are made. The table shows that the CCT reaches expected stable operating conditions in its fourth year of operation. Table 7-4 shows the financial data assumed for this analysis.

Cost Calculations

The cost analysis follows the standard engineering economics methods contained in EPRI's *Technology Assessment Guide* (*TAG*).[49] The total cost associated with each technology is broken into two parts: operating costs and carrying charges for capital costs. Operating costs include the fuel cost, the fixed O & M costs and the variable O & M costs. Carrying charges include a return on investment, depreciation, taxes and insurance. All the carrying charges can be expressed as a fraction to be applied to the total capital investment during each year of plant operation. The annual carrying charge fraction can be derived as a function of the book life, the tax recovery period, return on equity, interest rate on debt, the tax rate, and the after-tax discount rate. Tables of carrying charges for different combinations of the above financial parameters are available in EPRI's *TAG*[50] and can also be calculated with the software ECONLCC available from EPRI.

[49] Electric Power Research Institute, *Technology Assessment Guide* (Palo Alto, CA: Electric Power Research Institute, 1989).

[50] Ibid.

TABLE 7-3

CCT DATA INCLUDING INITIAL OPERATING RISKS

Year of Operation	Heat Rate (Btu/kWh)	Capacity Factor	Fixed O&M ($/kW-yr.)	Energy Generation (kWh)
1	9,391	0.50	34.5	1.314×10^9
2	9,100	0.55	33.0	1.445×10^9
3	8,819	0.60	31.5	1.577×10^9
4-30	8,537	0.65	30.0	1.708×10^9

TABLE 7-4

FINANCIAL PARAMETERS

Security Type	Cost (%)	Share of Total (%)	Weighted Return (%)
Debt	10.0	45.0	4.5
Preferred Stock	10.0	10.0	1.0
Common Stock	13.4	13.4	6.0
			11.5

Return on Capital

Inflation Rate	5.0%
Real Escalation Rate	1.5%
Federal & State Tax Rate	38.0%
After-Tax Discount Rate	9.8%

All calculated cost values are escalated and discounted using standard methods to obtain present values.

Table 7-5 shows the costs for the BT in the first year of operation (year 2000) in year-2000 dollars. These costs can be escalated and discounted over the operating life of the plant to obtain year-by-year costs over the book life of the plant. For the CCT, similar calculations (except for the capital cost) are performed for the first four years of operation (compared to first year calculations for the BT); they are shown in Table 7-6. Four years of calculations are needed for the CCT, as related costs vary over the first four years. The costs also include replacement power costs for the first three years at

TABLE 7-5

COSTS OF BT IN 2000 DOLLARS

	BT
Total Plant Cost	$(300{,}000\ kW)(\$1{,}434/kW)(1.05)^{12}$ $= \$772.6$ million
Total Fuel Cost	$(\$1.51/mmBtu)[(1.05)(1.015]^{12}$ $\times (10{,}044\ Btu/kWh)(1.708 \times 10^9\ kWh)$ $= \$55.6$ million
Fixed O&M	$(\$30/kW)(1.05)^{12}\ (300{,}000\ kW)$ $= \$16.2$ million
Variable O&M	$(6.0\ mills/kW)(1.708 \times 10^9\ kWh)(1.05)^{12}$ $= \$18.4$ million

TABLE 7-6

COSTS OF CCT IN 2000 DOLLARS

Year of Operation	Total Fuel Cost (million $)	Fixed O&M (million $)	Variable O&M (million $)	Replacement Power Cost (million $)
1	40.0	18.6	14.2	11.8
2	42.6	18.6	15.6	7.9
3	45.1	18.6	17.0	3.9

4-30	47.2	16.2	18.4	0

3 cents per kWh. As for the BT, the costs are escalated and discounted over the book life of the CCT.

Table 7-7 shows the present value of costs (in 2000 dollars) for the BT. For the CCT, the calculations are repeated, on a trial-and-error basis, to derive a total plant cost such that the cumulative value of costs closely matches the same for the BT in twenty years or less. The trial-and-error calculations yield a total plant cost value of $849.9 million. Therefore, the break-even capital cost is ($\$849.9 \times 10^6$)/[(300,000 kW)$(1.05)^{12}$] = $1,577 per kW (in 1988 dollars).

The above calculations show that the CCT can tolerate up to 10 percent higher capital costs with a stable heat rate improvement of 15 percent. If the projected heat rate improvement is less than 15 percent, then the corresponding capital cost increase for CCT needs to be less than 10 percent to reach the break-even point with the BT in twenty years or less. For simplicity, the above calculations ignore the lower pollution-control or environmental costs likely to be incurred by the CCT. If pollution control costs are included, the CCT may be able to tolerate a higher capital cost. The above calculations, however, are intended to illustrate, rather than exactly replicate, the analysis that would be needed in applying the incentive system in a real world situation.

The calculations demonstrate: (1) how various parameters should be set, and (2) the expected cost performance of a hypothetical CCT in terms of being considered a viable candidate for the proposed incentive system. Table 7-8 shows the present value of costs (in 2000 dollars) under an assumed capital cost of $1,577 per kW (in 1988 dollars).[51]

Revenue Requirements Analysis

After a viable technology is chosen and proper set of cost and performance parameters established, the next step is to examine the effect on revenue requirements upon initial application of the incentive system.

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[51] This forms the basis for calculating capital-related carrying charges.

TABLE 7-7

PRESENT VALUE OF COSTS (IN 2000 DOLLARS) FOR THE BT

Year of Operation	Capital Cost Carrying Charge (million $)	Fuel Cost (million $)	Fixed O&M (million $)	Variable O&M (million $)	Total Annual Cost (million $)	Cumulative Total Cost (million $)
1	155.5	55.6	16.2	18.4	245.7	245.7
2	137.1	54.0	15.5	17.6	224.2	469.9
3	120.2	52.4	14.8	16.8	204.3	674.2
4	105.8	50.9	14.2	16.1	186.9	861.1
5	92.9	49.4	13.5	15.4	171.2	1,032.3
6	81.6	47.9	13.0	14.7	157.2	1,189.4
7	71.5	46.5	12.4	14.1	144.4	1,333.9
8	62.9	45.1	11.8	13.5	133.4	1,467.2
9	55.3	43.8	11.3	12.9	123.3	1,590.6
10	48.5	42.5	10.8	12.3	114.2	1,704.8
11	42.5	41.3	10.4	11.8	106.0	1,810.7
12	37.2	40.1	9.9	11.3	98.5	1,909.2
13	32.5	38.9	9.5	10.8	91.7	2,000.9
14	28.4	37.8	9.1	10.3	85.5	2,086.4
15	24.7	36.7	8.7	9.9	79.9	2,166.3

TABLE 7-7--Continued

Year of Operation	Capital Cost Carrying Charge (million $)	Fuel Cost (million $)	Fixed O&M (million $)	Variable O&M (million $)	Total Annual Cost (million $)	Cumulative Total Cost (million $)
16	21.5	35.6	8.3	9.4	74.7	2,241.1
17	18.4	34.5	7.9	9.0	69.9	2,311.0
18	15.9	33.5	7.6	8.6	65.6	2,376.6
19	13.7	32.5	7.2	8.2	61.8	2,438.4
20	11.8	31.6	6.9	7.9	58.2	2,496.5
21	10.1	30.7	6.6	7.5	54.9	2,551.4
22	8.8	29.8	6.3	7.2	52.1	2,603.5
23	7.7	28.9	6.1	6.9	49.6	2,653.1
24	6.8	28.0	5.8	6.6	47.2	2,700.3
25	5.9	27.2	5.5	6.3	45.0	2,745.3
26	5.2	26.4	5.3	6.0	42.9	2,788.2
27	4.5	25.6	5.1	5.8	40.9	2,829.1
28	3.9	24.9	4.8	5.5	39.1	2,868.3
29	3.4	24.2	4.6	5.3	37.5	2,905.7
30	2.9	23.5	4.4	5.0	35.8	2,941.5

TABLE 7-8

PRESENT VALUE OF COSTS (IN 2000 DOLLARS) FOR THE CCT

Year of Operation	Capital Cost Carrying Charge (million $)	Fuel Cost (million $)	Fixed O&M (million $)	Variable O&M (million $)	Replacement Power Cost (million $)	Total Annual Cost (million $)	Cumulative Total Cost (million $)
1	171.1	40.0	18.6	14.2	11.8	255.7	255.7
2	150.9	41.4	17.8	14.9	7.6	232.5	488.1
3	132.3	42.5	17.0	15.5	3.6	210.9	699.0
4	116.4	43.2	14.2	16.1	0	189.8	888.8
5	102.2	41.9	13.5	15.4	0	173.1	1,061.9
6	89.7	40.7	13.0	14.7	0	158.1	1,220.0
7	78.6	39.5	12.4	14.1	0	144.6	1,364.5
8	69.2	38.3	11.8	13.5	0	132.8	1,497.4
9	60.8	37.2	11.3	12.9	0	122.2	1,619.6
10	53.4	36.1	10.8	12.3	0	112.6	1,732.2
11	46.8	35.1	10.4	11.8	0	104.0	1,836.2
12	41.0	34.0	9.9	11.3	0	96.1	1,932.3
13	35.8	33.0	9.5	10.8	0	89.1	2,021.4
14	31.2	32.1	9.1	10.3	0	82.6	2,104.0
15	27.2	31.1	8.7	9.9	0	76.9	2,180.9
16	23.6	30.2	8.3	9.4	0	71.5	2,252.4
17	20.3	29.3	7.9	9.0	0	66.5	2,319.0
18	17.5	28.5	7.6	8.6	0	62.2	2,381.1
19	15.1	27.6	7.2	8.2	0	58.2	2,439.3
20	13.0	26.8	6.9	7.9	0	54.6	2,493.9
21	11.1	26.0	6.6	7.5	0	51.3	2,545.2
22	9.7	25.3	6.3	7.2	0	48.5	2,593.7
23	8.5	24.5	6.1	6.9	0	46.0	2,639.7
24	7.5	23.8	5.8	6.6	0	43.7	2,683.3
25	6.5	23.1	5.5	6.3	0	41.4	2,724.8
26	5.7	22.4	5.3	6.0	0	39.4	2,764.2
27	4.9	21.8	5.1	5.8	0	37.5	2,801.7
28	4.3	21.1	4.8	5.5	0	35.8	2,837.5
29	3.7	20.5	4.6	5.3	0	34.1	2,871.6

30	3.2	19.9	4.4	5.0	0	32.6	2,904.2

In applying the incentive system, it is assumed that the utility is allowed to choose its annual sharing fraction in a way that drives the cumulative sharing fraction to as value close to the target sharing fraction. A sharing fraction of 1 is allowed in the first year of operation (making the revenue requirements the same as they would be under a cost plus contract). For the remaining years, the sharing fraction is limited to a range of values, 0.65 to 0.95. Also, the cumulative sharing fraction must, match the target sharing fraction by the twenty-fifth year of operation.

Assume that the target life cycle sharing fraction, X_t is 0.80. Table 7-9 shows the results of applying the incentive system. The utility chooses a sharing fraction of 1 during the first year of operation, followed by sharing fractions of 0.95, 0.95, 0.9, and 0.9 in the following four years. After the fifth year, the sharing fractions are successively adjusted downward and upward to drive the cumulative sharing fraction close to 0.80, the target life cycle sharing fraction. As the utility chooses relatively high sharing fractions during the initial operating period to minimize potential revenue shortfalls, it also shares a relatively higher fraction of revenue surpluses in later years with ratepayers. The target life cycle sharing fraction is reached in the twenty-second year of operation.

Table 7-9 contains some other important observations. The utility experiences annual revenue shortfalls in the first six years of operation after which it achieves revenue surpluses. The revenue surpluses offset the earlier revenue shortfalls in the twenty-first year after which the utility enjoys a net revenue surplus. As a result of the incentive system and assumed superior performance of the CCT, the ratepayers gain $29.9 million in revenue requirements over the life cycle of the CCT compared with the case of a conventional technology and traditional ratemaking treatment. The utility gains an additional $7.5 million over its total cost for the CCT.

The numerical example presented demonstrates that the incentive system is feasible if the assumed performance levels can be achieved for the hypothetical CCT, and for that matter, any IGT. The success of the incentive system, also depends on the risk perceptions and risk attitude of the utility. While the assumed data may appear to be optimistic in favor of the CCT, the data does not include additional cost advantages from superior environmental performance of the CCT and improvements in capacity

TABLE 7-9

PRESENT VALUE OF REVENUE REQUIREMENTS UNDER INCENTIVE SYSTEM

Target Life Cycle Sharing Fraction = 0.8

Year of Operation	Annual Sharing Fraction	BT Annual Cost (million $)	BT Cumulative Cost (million $)	CCT Annual Cost (million $)	CCT Cumulative Requirements (million $)	Annual Revenue Requirements (million $)	Cumulative Revenue Requirements	Cumulative Sharing Fraction
1	1.00	245.7	245.7	255.7	255.7	255.7	255.7	1.00
2	0.95	224.2	469.9	232.5	488.1	232.1	487.7	0.98
3	0.95	204.3	674.2	210.9	699.0	210.5	698.3	0.97
4	0.90	186.9	861.1	189.8	888.8	189.5	887.8	0.96
5	0.90	171.2	1,032.3	173.1	1,061.9	172.9	1,060.7	0.96
6	0.85	157.2	1,189.4	158.1	1,210.0	157.9	1,218.6	0.96
7	0.85	144.4	1,333.9	144.5	1,364.5	144.6	1,363.2	0.96
8	0.85	133.4	1,467.2	132.8	1,497.4	132.9	1,496.1	0.96
9	0.85	123.3	1,590.6	122.2	1,619.6	122.4	1,618.4	0.96
10	0.85	114.2	1,704.8	112.6	1,732.2	112.9	1,731.3	0.97
11	0.90	106.0	1,810.7	104.0	1,836.2	104.2	1,835.5	0.97
12	0.90	98.5	1,909.2	96.1	1,932.3	96.4	1,931.9	0.98
13	0.90	91.7	2,000.9	89.1	2,021.4	89.3	2,021.2	0.99
14	0.90	85.5	2,086.4	82.6	2,104.1	82.9	2,104.1	1.00
15	0.90	79.9	2,166.3	76.9	2,180.9	77.2	2,181.3	1.03
16	0.95	74.7	2,241.1	71.5	2,252.4	71.7	2,253.0	1.05
17	0.95	69.9	2,311.0	66.5	2,319.0	66.7	2,319.7	1.09
18	0.95	65.6	2,376.6	62.2	2,381.1	62.3	2,382.0	1.20
19	0.95	61.8	2,438.4	58.2	2,439.3	58.4	2,440.4	2.09
20	0.90	58.2	2,496.6	54.6	2,493.9	54.8	2,495.2	0.52
21	0.90	54.9	2,551.4	51.3	2,545.2	51.6	2,546.8	0.74
22	0.80	52.1	2,603.5	48.5	2,593.7	48.8	2,595.7	0.80
23	0.80	49.6	2,653.1	46.0	2,639.7	46.7	2,642.4	0.80
24	0.80	47.2	2,700.3	43.7	2,683.3	44.4	2,686.7	0.80
25	0.80	45.0	2,745.3	41.4	2,724.8	42.1	2,728.9	0.80
26	0.80	42.9	2,788.2	39.4	2,764.2	40.1	2,769.0	0.80
27	0.80	40.9	2,729.1	37.5	2,801.7	38.2	2,807.2	0.80
28	0.80	39.1	2,868.3	35.8	2,837.5	36.4	2,843.6	0.80
29	0.80	37.5	2,905.7	34.1	2,871.6	34.8	2,878.4	0.80
30	0.80	35.8	2,941.5	32.6	2,904.2	33.2	2,911.6	0.80

factors that can be gained by relatively small expenditures on operation and maintenance activities. The assumed data also establish combinations of parameters that need to be achieved by a CCT before it can gain from, and perhaps be entitled to, a ratemaking incentive.

Implementing the Incentive

Underlying Assumptions and Potential Concerns

Both the conceptual design and the numerical demonstration of the proposed partial incentive system are based on a set of explicit or implicit assumptions that may be open to question and therefore need to be addressed in implementing the system. It should be observed that the incentive is intended to be voluntary and flexible: utilities are offered but not required to accept the incentive, and the incentive can be tailored for the specific needs and characteristics of individual state commissions and utilities. Therefore, both the conceptual design and the numerical illustration of the incentive include only the generic ratemaking features; they leave out many details that would have to be included in an actual implementation. In particular, the numerical illustration is not intended to convey, in complete detail, either the analytical complexity or all the ramifications of an actual implementation of the system. The numerical illustration uses a minimal set of input data to allow a simple and uncluttered demonstration of its basic features. The exclusion of any relevant variable in the illustration should not be interpreted as a restriction on the variable in an actual implementation.

To summarize, the proposed incentive system is sufficiently generic, broad and flexible to allow incorporation of all costs and benefits that merit consideration on clear economic efficiency or public-interest grounds but that were not explicitly included in the numerical example. The only requirements for developing specific applications of the incentive are that two of its main features, namely a symmetric risk/reward structure and cost minimization, are preserved.

It is, however, important to reexamine the underlying assumptions of the conceptual design and the numerical illustration of the incentive system to better address potential concerns that may arise in application.

Retrospective Disallowances and Utility Performance

The incentive system presupposes restricted use of *ex post* reviews to disallow utility investments and expenses. The system presumes that its adoption by agreement between the state commission and the utility constitutes a determination of need for a generation technology with a number of desired characteristics. This implies a firm commission commitment to the investment decision with very little need for later review.

There needs to be a mechanism, however, to ensure a minimal acceptable level of utility performance. Therefore, setting up intermediate cost and performance targets, and periodic reviews may be required to ensure that these targets are met. Such reviews may be limited to evaluating management performance outside of the initial technology choice decision.

Expected Costs and Risks

The incentive system assumes that an IGT is likely to cost less than a CGT over a typical life cycle; it is also assumed that there are higher performance risks associated with the IGT, and that these risks may be realized mostly during construction and initial operating years of the IGT. It should be emphasized that the assumption of lower expected life-cycle costs for the IGT may not necessarily hold for a first generation, precommercial plant. In other words, the performance risks, either in magnitude or in duration, may be high enough to more than offset any cost advantages for a precommercial IGT over a CGT during one life cycle. It is expected, however, that subsequent generations of the IGT may progressively overcome these risks and realize significant cost savings over the CGT (see Figure 7-8). One may argue that such savings can be realized only after the IGT has been fully commercialized and that an incentive

Fig. 7-8. Capital cost learning curve (Source: Electric Power Research Institute, *Technical Assessment Guide*, EPRI P-46587-L (Palo Alto, CA: Electric Power Research Institute, September 1989).

system applicable to one life cycle of a precommercial IGT is unlikely to encourage adoption. Also, one may observe that even if the life-cycle costs of the IGT were comparable or less than the CGT, the risk/return ratio[52] associated with the IGT may still be unfavorable relative to the CGT.[53] Therefore, even with potential cost advantages over a life cycle, the IGT may not be adopted by a utility.

Pollution Control and Environmental Benefits

The incentive system does not make any explicit assumptions about either the pollution control costs or the value of pollution reduction benefits of either the IGT or the CGT. It is implicitly assumed that the CGT would require add-on pollution control devices to achieve the same level of pollution reduction as the IGT, which is inherently less polluting. The numerical illustration includes the capital and the operating costs of an add-on pollution control device (namely an FGD or scrubber)[54] required for the CGT in cost comparisons performed between the CGT and the IGT. As long as total emissions of any pollutant are comparable for both the CGT (with add-on pollution control) and the IGT, any separate comparison of pollution control costs or pollution reduction benefits would be unnecessary. If the IGT has lower emissions of any specific pollutant than the CGT, however, imputing a value on the additional pollution reduction achieved by the IGT may be warranted. Therefore, the incentive system may incorporate any residual or incremental environmental benefits that could be realized by adopting the IGT.

[52] The incentive eliminates or significantly reduces the regulatory risk but leaves the performance risks unchanged.

[53] See the discussion in Chapter 3 on how investment choices are influenced by the relationship between risks and returns.

[54] The add-on pollution control devices need not be limited to conventional scrubbers. Controls for pollutants other than SO_2, such as low NO_x burners, as well as other technologies, including retrofit CCTs, and their costs can be included in the cost analysis to be performed under the incentive system.

Besides environmental benefits, other social benefits of adopting the IGT that are not explicitly incorporated in the numerical illustration of the proposed incentive system may be present.[55] Such benefits include preservation of local jobs that depend on a local resource or fuel such as coal, expansion of export markets for local resources and technologies that use such resources, and technology spinoffs that may have a beneficial effect on other parts of the economy. One can argue that although the proposed incentive removes some of the existing regulatory barriers (most important, the asymmetric risk/reward structure) and attempts to level the "playing field" between IGTs and CGTs, it may need to do more in recognition of potential social benefits.

Use of Fuel Adjustment Clauses (FACs)

The incentive system does not explicitly favor or discourage the use of FACs, either in conjunction with the incentive, or as continuation of a current regulatory practice. The numerical illustration, which involves an IGT and a CGT each using the same fuel, assumes that there is no FAC in operation. In fact, the inclusion or exclusion of a FAC is not expected to make any difference in cost comparisons between the CGT and the IGT that use the same fuel because the same adjustments are to be made for both to account for fuel price fluctuations. If the two technologies use different fuels, use of a FAC as a separate adjustment outside of the incentive may favor the more fuel-intensive technology or the technology with higher or more volatile fuel prices. Continuation of the FAC as a general regulatory practice also may favor fuel-intensive technologies over capital-intensive ones (which most IGTs are) and therefore may discourage utilities from accepting the proposed incentive. What a commission should do about this potential problem would need to be addressed in implementing the incentive system.

[55] See Chapter 2 for a discussion of potential social benefits of adopting a IGT.

Recommendations for Addressing Potential Concerns

Ensuring Acceptable Performance

A number of concerns need to be addressed to ensure the minimum acceptable level of utility performance with the IGT. They are: construction cost overruns, lower than expected capacity utilization, and higher than expected pollutant emissions.

To ensure that construction cost overruns are not excessively high, a set of two construction cost bands can be set. If the construction cost is below or within the lower band, no adjustments are made to revenues and all capital related charges are recoverable. If the construction cost is within the upper band, the utility and ratepayers share the cost. This sharing fraction can differ from the sharing fraction used for the life-cycle cost. In both cases (construction costs in the upper or the lower band or below the lower band), however, construction costs and capital-related charges would have to be reconciled with the recovery of the life-cycle cost. Finally, if the construction cost rises beyond the upper band, the utility absorbs the entire excess cost. This would represent an unrecoverable penalty to the utility, with no subsequent adjustment to revenues.

Similar mechanisms can be developed for capacity utilization and pollutant emissions Unlike construction costs, it is sufficient to have one performance band. Within this performance band (an acceptable capacity factor or acceptable levels of pollutant emissions), all costs within the framework of the incentive (with appropriate sharing) are recoverable. Below the performance band (a low capacity factor or high levels of pollutant emissions) cost penalties may be assessed against the utility; these adjustments would be unrecoverable through later adjustments.

Overcoming Cost and Risk Barriers

Two major concerns of the proposed incentive system arise. First, life cycle costs of the IGT may be higher than the CGT; and second, even if the expected costs are comparable or lower for the IGT, the higher riskiness of the IGT may offset any cost advantage it would have over the CGT.

Several approaches exist to address the possibility that the expected life-cycle costs may be higher for a precommercial IGT than for a CGT. Two such approaches, which have been discussed in an earlier part of this chapter, are: pooling of investments by several utilities into an IGT, and extending the incentive over several generations of IGT plants without making offsetting cost adjustments for improvements in technical and economic performance. Another approach would be to provide a credit to the IGT that matches some fraction of the total expected cost savings that would be achieved after full commercialization of the IGT.

To the extent that the capital markets respond to various investments with different risk/return possibilities, the higher riskiness will be reflected by the cost of capital associated with the financing of an IGT project. This provides an index that can be used to equalize the financial risks for the two technologies under consideration. Under traditional ROR regulation, the allowed ROR could be adjusted upward to accurately reflect the true cost of capital for the IGT. Under the proposed incentive system, however, a different adjustment is in order. A state commission might consider using the cost of capital for the IGT to derive the capital-related carrying charges for the CGT. In other words, the same cost of capital would be used to calculate the capital-related charges for the IGT and the CGT. This puts the capital component of the bench-mark cost of the CGT on the same footing as the IGT.

Incorporating Environmental and Social Benefits

To address the issue of incremental or residual environmental benefits of the IGT, it is important to distinguish between three categories of pollutants: criteria pollutants that are tradeable, criteria pollutants that are subject to mandatory emission control standards, and noncriteria pollutants.

For tradeable criteria pollutants (which currently is SO_2 under the Clean Air Act Amendments of 1990), the residual emission reduction achieved by the IGT becomes a tradeable commodity. The utility will have to buy fewer allowances to meet environmental compliance requirements for the IGT than for the CGT. To incorporate this effect in the incentive system, the cost comparison between the CGT and IGT should include the cost of purchasing allowances needed for each technology. It is assumed that the market price of an allowance represents the appropriate value that the state commission attaches to one fewer unit of the tradeable pollutant. If a commission prefers to assign a different value to a unit of the pollutant, then an additional adjustment may be needed in applying the incentive system. Given the difficulty of quantifying environmental benefits, the commission may choose to provide a credit to the IGT or impute a cost to the CGT based on its best subjective evaluation.

For criteria pollutants (such as NO_x) subject mandated control standards, and for noncriteria pollutants (such as CO_2), the commission may wish to assign a credit based on its subjective preference.[56] Following the example of regulation of SO_2 under the Clean Air Act Amendments of 1990, several states have taken the view that no externality exists if incremental emissions are offset, resulting in no net changes in emissions. For such regulators, the value of reducing a unit of pollution might be the savings associated with not having to offset the pollution.

To incorporate social benefits other than environmental, the commission could conduct a cost-benefit analysis of alternative technology choices to derive the appropriate credit to be imputed to the IGT. If the resource constraints of the commission make such a study burdensome, then, as in case of environmental benefits, the commission can impute a credit to the IGT based on subjective preference.

Overcoming the FAC Disincentive

For the two technologies under consideration, no FAC mechanism is needed if the operating costs of a bench-mark CGT are automatically indexed for fuel price fluctuations. It is important to note that the utility could not adjust its rates based on the fuel price fluctuations for the IGT. Therefore, the utility has an automatic incentive to use fuels with low, stable prices.

Whether FACs should be allowed outside of the incentive system is a separate issue that may affect the willingness of a utility to accept the proposed incentive. Since the incentive itself does not allow automatic passthrough of fuel costs, the existence of the FAC mechanism may cause the utility to opt for other technologies with high or volatile fuel prices or high fuel consumption but with lower capital costs. This may cause the utility unwilling to accept the incentive (which is voluntary). A commission therefore, may wish to reexamine its FAC policy

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[56] Many state commissions currently use "externality adders" for various pollutants, often using the surrogate of control costs. The rationale for this approach is the difficulty of estimating the actual environmental damage, which would have been the ideal index, caused by a pollutant. This proxy quantification of environmental costs, however, may be viewed as faulty, and no more appropriate than a purely a subjective and qualitative valuation.

and consider appropriate reforms.[57]

Summary Recommendations for Implementing the Incentive

The foregoing discussion indicates that in implementing the partial incentive, a commission would have to establish a mechanism that ensures minimum acceptable utility performance, consider assigning credits to the precommercial IGT to account for potential future benefits, and reexamine its FAC policy.

To ensure acceptable performance, the setting up of cost and performance bands with penalties for not meeting the corresponding criteria is suggested. For assigning credits, a commission should at the minimum consider four factors: higher first generation commercialization costs, higher risks, environmental benefits and social benefits. Finally, in reexamining its FAC policy, the commission should consider the effect on the technology choice and whether a bias exists toward choosing fuel-intensive technologies with high or volatile prices over capital-intensive technologies with low or stable fuel prices. Either elimination or reform of FAC policies should be examined.[58]

Among the three policy issues, the issue of assigning credit to the IGT requires further discussion. It is suggested here that all the applicable credits be combined into a single credit for the IGT. The appropriate economic rationale for providing such a credit can found in the notion of opportunity costs. Such a credit captures the cost of foregone private (to the ratepayers) and social (spillover) benefits of not adopting the IGT: lower rates in the long run (after commercialization), more efficient utilization of a local resource, a better environment, and support to local economic interests.

There are several ways of incorporating the credit to the IGT. The credit can be used to offset IGT costs or adjust BT costs or can be offered as a bonus to the IGT outside of the incentive. Among the first two options, assigning an additional cost to the estimated costs of the

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[57] See the discussion on FACs in Chapter 4 and in an earlier part of this chapter.

[58] One suggested reform is using a fixed weight automatic adjustment clause (AAC) as proposed in Robert E. Burns, Mark Eifert, and Peter A. Nagler, *Current PGA and FAC Practices: Implications for Ratemaking in Competitive Markets* (Columbus, OH: The National Regulatory Research Institute, 1991).

BT, seems preferable. This is because it would require no other adjustment to incentive calculations and also because it adjusts an estimate (for the BT) rather than actual costs (for the IGT). The third option, providing a separate bonus for the IGT outside of the incentive system, may not be preferred because by essentially offering a risk-free subsidy, the intended cost-minimizing feature of the incentive may be compromised.[59]

Choosing the level of credit presents a formidable challenge for the commission and requires a balance of two conflicting considerations. On the one hand, the credit must be sufficiently high to make the utility indifferent between a CGT and the IGT. On the other hand, the credit must match and not exceed the commission's assessment of the benefits to ratepayers and the state as a whole. To address the first issue, a recent study by Argonne National Laboratory[60] suggests an estimate of the credit, termed "the incremental cost of risk," based on a decision tree analysis of various economic and technical performance risks. The biases of the party (the commission or the utility) performing the estimation, whether using the Argonne method or any other method, however, is likely to affect the estimated value of the credit. Also, the informational asymmetry between the utility and the commission puts the commission at a disadvantage in establishing a mutually acceptable value for the credit. Ultimately, the credit will be a negotiated value, something that both parties "can live with" and also acceptable to public interveners if subsequent court challenges are to be avoided. For example, a credit of approximately 10 percent to 20 percent may be acceptable to some state commissions.

Tailoring the Incentive for NUGs

State commissions may also wish to explore whether some variant of the proposed incentive can be applied to induce NUGs to adopt an IGT that meets the appropriate economic efficiency and public interest tests. One suggested approach would be to offer the incentive to a

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[59] Another alternative is to consider a performance-based bonus such as a capacity utilization bonus, which would not exceed the value of the credit over the life of the plant. This incentive allows a utility to earn an additional amount (for example, of a few mills per kWh) for meeting a capacity factor target. For more discussion of this alternative, see Ibid.

[60] K. A. McDermott, K. A. Bailey, and D. W. South, *Examination of Incentive Mechanisms for Innovative Technologies Applicable to Utility and Nonutility Generators,* ANL/EAIS/TM-102 (Argonne IL: Argonne National Laboratory, August 1993), 41-56.

utility regardless of whether the utility chooses to build or purchase the needed capacity. If the utility chooses to purchase the capacity, the bench-mark costs (with appropriate opportunity cost adjustments for future ratepayer and social benefits of the IGT) would assume the role of avoided costs. Assuming that the contracting process in place between the utility and its NUG suppliers is properly designed, the above incentive will lead to an efficient sharing of the utility portion of the potential gains between the utility and NUGs. Given the fact that a typical IGT project may be financially onerous for a typical NUG, pooling of investments by several NUGs and allowing joint bids for a single project should also be considered. The entry of large (utility and nonutility) exempt wholesale generators into the bulk power market allowed by the EPAct also offers a utility the possibility of entering into a single-supplier, IGT-project contract. Finally, to put IGTs at an equal footing with other supply side and demand-side options that have potential environmental and social benefits, a commission may want to consider redesigning the scoring system for power procurement bids to include the beneficial features of IGTs.

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CHAPTER 8

SUMMARY AND CONCLUSIONS

The electric power industry is poised for a period of rapid evolution. Three basic forces--energy efficiency, environmental control, and greater competition--shaping the industry's course over the last two decades are also likely to drive its evolution in the next decade.

As state regulatory commissions and environmental regulators demand greater energy efficiency and environmental performance, and markets for wholesale power and tradeable emissions develop more fully, utilities and other power producers are faced with a complex array of generation technology choices and energy management options to meet their power demand and environmental compliance requirements. The decisionmaking process on these complex choices will be shaped by the policies and practices of regulators.

Most of the energy needs of the power industry are currently met by conventional generation technologies. The current generation mix is dominated by coal, nuclear, hydro, and natural gas plants. As the implementation of recent federal legislation, namely, the Clean Air Act Amendments of 1990 and the Energy Policy Act of 1992, leads to more stringent environmental controls and greater competition in the wholesale power markets, utilities and other power producers will increasingly look to more cost-effective and environmentally cleaner technologies as their generation choices. A number of innovative generation technologies (IGTs) are under development and are currently at the precommercial stage where they could potentially meet the needs of power producers before the turn of the century. They include clean coal technologies (CCTs), advanced nuclear designs, and advanced renewable technologies. A number of promising technologies exist to utilize electricity more efficiently--that is, to provide the same services with less electricity.

The IGTs offer more energy efficient and environmentally superior alternatives to conventional technologies; they also affect many national and local interests such as energy security, environmental quality, economic growth, employment, and competitiveness in foreign energy markets. As many of these technologies complete precommercial scientific development and commercial readiness, they may become contenders to conventional technologies.

In spite of the many potential benefits of IGT commercialization, the study finds that market and institutional barriers may inhibit the adoption of IGTs at a socially desired rate. The study observes that the two major categories of potential IGT adopters, namely investor-owned electric utilities (IOUs) and nonutility generators (NUGs), encounter different kinds of barriers.

The study makes some general observations about the risk/reward structure inherent in the regulatory arrangement. The study finds that the asymmetry of the risk/reward structure in the regulatory arrangement is a major impediment to risk-taking and innovation by utilities. Simply, the nature of regulation does not adequately compensate a firm for the risk-taking associated with IGTs: the asymmetric risk/reward structure penalizes failure while only moderately rewarding success from risky innovations. This feature of regulation tends to bias the technology choices of IOUs in favor of low-risk, conventional alternatives. The study observes that while the risk/reward structure in an unregulated market is generally more symmetric and therefore more attractive for innovation than under regulation, project financing tends to hinder investment in IGTs.

Next, the study discusses the capital market perspective of a utility's investments. Using a simple example, it shows that the riskiness of an individual investment is unimportant to the investor with a portfolio of investments. What is important, instead, is the diversifiability of the risk determined by the interaction of this risk with the rest of the investor's portfolio. The expected return plays a more critical role in determining an investor's choices. Bounds on earnings imposed by regulators may depress the expected rate of return below the cost of capital, leading to the rejection of an investment, including economical ones. For risky projects, this means that the capital market may demand a higher return in general. Riskiness of projects also may have a higher adverse effect on the utility management than on its investors, since investors are better able to diversify their risks. This implies that management would sometimes reject risky projects when investors would not.

The study carries out a detailed review of various features of stylized rate-of-return regulation (ROR), focusing on its effect on the adoption of IGTs. It examines such basic features of regulation as monopoly status of the regulated firm, regulatory lag, bounds on earnings, bounds on risks, fuel adjustment clauses (FACs), and retrospective disallowances.

It is observed that monopoly status has conflicting incentives for innovation. On the one hand, an unregulated monopolist can appropriate all the savings of innovation without worrying about competitors imitating its product. On the other hand, a monopolist (unregulated ones and regulated ones whose prices lie above marginal cost) restricts output below the competitive level and reductions in marginal cost will be spread over fewer units. This makes innovation, assuming other things held constant, less attractive to the monopolist than the competitive firm.

Regulatory lag also has mixed incentives for innovation, depending on both size of the investment and whether input prices are declining or increasing. In general, regulatory lag provides incentives for inexpensive innovations with short payback periods. Also, in periods of declining costs, such as occurred in the 1950s and 1960s in the electric power industry, utilities may be in a better position to finance new projects if rates are not frequently adjusted downward. The opposite effect occurs when innovations are expensive or costs are increasing.

Bounds on earnings generally discourage innovation. Based on the economics literature, it is concluded that both bounds on earnings and electricity prices have important effects on the choice of factor inputs. Averch and Johnson, for example, held that firms tend to overcapitalize when rates of return are higher than the cost of capital. By the same token, firms are unlikely to engage in risky projects if the upper limit on the ROR is binding and the downside risk is less binding. Joskow held that nominal electricity prices rather than ROR trigger rate reviews and adjustments to a utility's earnings. Overall, bounds on earnings have a negative impact on innovation.

FACs affect a utility's choices of fuel and other inputs and may have important implication for its technology choices. FACs were instituted to keep the utility financially viable under inflationary conditions in the fuels market. FACs may bias a utility toward fuel-intensive technology choices in general and fuels with volatile prices in particular. This suggests that utilities, relative to other choices, will favor fuel-intensive technologies and fuels with relatively volatile prices. Consequently, other things held the same, capital-intensive technologies such as renewables, nuclear, and coal generators may have a relative comparative disadvantage.

Retrospective disallowances are another regulatory practice that has important ramifications for the investment choices of a utility. In the 1980s, the prudence test and the "used and useful" test were invoked to disallow over $15 billion of electric utility costs. The vast majority of the disallowances were capital costs for nuclear plants.

Hindsight reviews may induce firms to reduce investments and avoid risks. It can be argued, however, that hindsight reviews may also protect against an excessive preference for large risky investments. If innovative technologies, for example, merely have the same expected costs and expected environmental emissions as conventional technologies, nothing is lost if utilities eschew them. In fact, society may be better off if unnecessary risk are avoided. If innovative technologies, on the other hand, have lower expected costs and other benefits or equal expected costs but lower environmental emissions, then regulation that biases utilities toward conventional technologies may be contrary to the public interest.

The historical experience with such innovations as nuclear power, supercritical coal, hot-side precipitators, and forced draft boilers suggest that regulated utilities were willing to experiment with new technologies prior to the era of retrospective disallowances when macroeconomic conditions (for example, declining nominal electricity costs) were more favorable. Regulation itself has changed its character over the last two decades, however, during which there has been an escalation of oversight and scrutiny. There is now a combination of extensive regulatory and judicial precedent and state laws, which would make it difficult for regulators not to consider disallowances under a broad variety of circumstances. This undoubtedly has contributed toward changing the risk posture of utilities to where they are now less willing to invest in risky innovative technologies.

Examining the effects of regulation on utilities provides several important insights. The effects of hindsight review (retrospective disallowances) and FACs tend to reinforce each other and outweigh the offsetting effects of bounds on risks. This combination appears to favor such technologies as gas combined-cycle (small, fuel-intensive, consuming a fuel with volatile prices) as opposed to coal-fired plants (larger, more capital-intensive, with more stable fuel prices) or nuclear plants (large and capital-intensive) and renewables (extremely capital-intensive).

Prospective prudence can mitigate the risk-avoidance effects of retrospective prudence and, consequently, stimulate investments in new technologies. On the negative side, it can create inefficiencies owing to the informational asymmetry between the regulator and the utility. This may motivate the utility not to exercise sufficient prudence and diligence in its decisions and operations without the possibility of detection by the regulator. Outcome-based regulation, as in retrospective prudence reviews, guards against this possibility. It is suggested that some combination of prospective and retrospective prudence may be desirable. Designing such an incentive mechanism would, however, be difficult.

Price caps is discussed as another possible approach for designing stronger incentives for risk-taking and efficient management. Price caps, by allowing an individual firm's costs to be detached from its earnings, would provide strong incentives for efficient decisionmaking. Difficulties arise, however, in specifying parameters such as inflation and productivity indices, the length of the regulatory lag, and the sharing fraction. It is observed that experience with price caps in telecommunications should provide a useful guide to examine and develop such regulatory systems for the electric sector.

Finally, the study examines the issue of IGT adoption by NUGs. The study finds that NUGs, whose profits are less constrained by regulation, confront different barriers to IGT adoption. Most NUGs are small and use highly leveraged debt-financing to fund construction projects. Small asset bases of NUGs, relative to the size of the investment in a typical IGT project, make it difficult to obtain financing on other than a project-financed basis. Debt financing, especially when backed by a project instead of by a large company, requires higher performance guarantees and rarely can be used to finance high-risk projects.

The adoption of IGTs, or any technology for that matter, by NUGs depends primarily on the willingness and ability of regulated utilities to purchase power in the wholesale power market. Current regulatory practices give utilities weak incentives to purchase power: most states allow utilities to recover on a dollar-for-dollar basis the prudent costs associated with power purchases. It can be argued that since purchased power is not risk free, utilities are being undercompensated for the power they purchase. Further, state commissions have increasingly allowed utilities to profit from demand-side management (DSM) activities. Consequently, it makes economic sense that if purchased power is to be on a "level playing field" with DSM and the less risky kinds of internal generation, a utility should be permitted to profit from least-cost purchases. The comprehensive incentive system proposed in this report would appear to achieve this objective.

An obstacle to the adoption of IGTs by nonutilities may be the highly risk averseness of utility managers and the risk-averse character of state regulation. For both utility managers and regulators the expected gains from use of IGTs may be insufficient, given the possibility of negative outcomes. Some regulators, for example, may discourage utilities from purchasing power produced by IGTs because of their belief that such technologies are less reliable and more prone to unanticipated problems than conventional technologies. Utilities may simply believe that nonutility generation from IGTs imposes uncompensated risk. Common features of purchased power contracts between NUGs and utilities reflect this perception, notwithstanding the risk burden imposed on generators.

The last part of this study examines different incentive systems that regulators can consider to offset the current asymmetric risk/reward relationship facing regulated electric utilities. Given the expected rise of competition in the electric power industry, the report strongly supports consideration by state commissions of comprehensive incentive systems. These include price caps, profit sharing, and hybrid systems. Although comprehensive systems provide potentially strong incentives for promoting IGTs, they may not be readily accepted by state regulators. In the short term, state regulators may want to consider specific incentives targeted at promoting IGTs. To the extent that IGTs have public benefits that are not internalized by a utility or not adequately addressed by the federal government, state regulators may want to sanction incentives that would exceed those justified only by the asymmetric risk/reward environment facing utilities.

This report examines in detail two incentive systems. The first, a comprehensive system, combines the features of price caps and profit sharing. The incentive system should enhance a utility's incentive (relative to ROR regulation) to innovate for three reasons. First, it would eliminate or at least lessen the need for retrospective prudence reviews. Second, by lengthening regulatory lag, it increases the utility's share of economic gains from innovation. Third, the utility would achieve higher long-term profits from successful innovations.

The second incentive mechanism closely examined, the "Cost Sharing of Life Cycle Costs" system, attempts to achieve construction and operation targets for individual generation facilities. Although the system is partial in nature, it is more broad-based than most partial systems in that it applies a composite target of maximizing both construction and operating performance over the life of a facility.

The authors of this report recommend that these two incentive systems be given serious consideration by state public utility commissions. Some commissions, however, may find other incentive systems such as those identified in Chapter 6 more appropriate for utilities under their jurisdiction.

Finally, the study finds that the public benefits of IGTs may warrant state regulatory commissions to offer special incentives. Such incentives, as much as possible, should preserve traditional regulatory goals of protecting ratepayer interest in addition to ensuring cost-efficient and prudent management.

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APPENDIX A

EMERGING INNOVATIVE GENERATION TECHNOLOGIES AND THEIR FEATURES

Over the last two decades, growing concern for energy independence, energy efficiency and environmental protection, and consequent public regulation has created an interest in generation technologies that better utilize domestic resources, are more energy efficient and environmentally more benign than conventional alternatives. In response, federal and state agencies, in cooperation with utilities and equipment vendors, have made a sustained effort to develop technologies with the intended features.[1] The following sections describe various promising innovative generation technologies (IGTs) currently under development. The description highlights cost, performance and potential for commercial deployment for various IGTs.

Types of Innovative Generation Technologies

The IGTs can be divided broadly into three main categories based on fuel or primary energy source. They are fossil-based, nuclear, and renewable. Innovative fossil-based technologies primarily consist of clean coal technologies (CCTs) that can potentially achieve significant reduction of such environmental pollutants as sulfur dioxide (SO_2), nitrogen oxides (NO_x), other atmospheric pollutants, and liquid and solid wastes that are common to the conventional pulverized coal-fired plant. Innovative nuclear technologies comprise new designs that feature advanced designs with enhanced safety features for conventional units (evolutionary)

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[1] Several development and demonstration programs initiated and cofunded by federal agencies are currently in place to expedite the commercialization of innovative generation technologies (IGTs). They include the Clean Coal Technology Demonstration Program initiated in 1986. See U.S. Department of Energy, *Clean Coal Technology Demonstration Program, Program Update 1992* (Washington, D.C.: U.S. Department of Energy, February 1993). Large research and development programs exist for nuclear and renewable technologies.

as well as other designs that feature smaller units with passive safety systems. Innovative renewable technologies attempt to achieve improved conversion to either heat or electricity from solar, geothermal and wind energy resources, and better integration with the electric supply grid for central station and utility applications.

Clean Coal Technologies

To understand the features of CCTs, it is helpful to review the basic design of the conventional pulverized coal-fired plant and then underscore the improvements in energy efficiency and pollution reduction that can potentially be achieved by the new technologies.

The Conventional Coal-Fired Plant

The conventional pulverized coal-fired (PC) plant design is shown in Figure A-1. Coal is pulverized (ground into small particles) in coal handling facilities and fed into a burner. Combustion of coal in the burner chamber is supported by injection of air. The hot gases produced by the burner is used to generate steam in water carrying tubes in a boiler. The steam is then used to drive a turbine and produce electricity.

The conventional coal plant produces three different types of wastes and pollutants. Ash is produced at the burner and is rejected through an outlet for disposal. Fly ash and other solid particulates that escape the boiler are trapped in dust collectors.[2] Finally, flue gases are rejected through the smoke stack in the atmosphere. Two of the flue gases are known to be significant pollutants: sulfur dioxide (SO_2), which is produced by the combustion of sulfur impurities in the coal, is a primary cause of acid rain; and nitrogen oxides (NO_x), which are produced by the combustion of atmospheric

[2] Dust collectors may include cyclones, baghouses, electrostatic precipitators (ESP), and ceramic filters.

Fig. A-1. Conventional coal-fired electric plant (Source: Ohio Department of Development, Ohio Coal Development Office, *Ohio Coal Development Agenda* (Columbus, OH: State of Ohio, 1992), 66.

nitrogen as well as nitrogen impurities in the coal, are also known to be a acid rain precursor.[3]

Several possible ways exist to reduce the levels of various pollutants emitted by a conventional coal-fired plant. At the precombustion stage, the coal can be processed to reduce impurities such as sulfur that are responsible for producing pollutants or to generally improve the combustion properties of coal. At the combustion stage, the chemical processes in the boiler can be modified to achieve reductions in pollutant emissions. Finally, at the postcombustion stage, the flue gases can be processed or "scrubbed" to remove pollutants. The three basic pollution control alternatives are known, respectively, as precombustion cleaning, clean combustion and postcombustion cleaning. Other options include coal conversion, in which the coal is converted to another form (such as gas) prior to combustion and processes that do not use combustion at all.

Conventional Pollution Control Technologies

Conventional coal-based technologies already use some forms of precombustion and postcombustion cleaning. Clean combustion is beginning to be used in coal plants in commercial operation.

Conventional precombustion cleaning uses physical separation techniques that rely on differences in physical characteristics such as density and surface properties. Two widely used techniques are froth floatation and gravity separation. Such physical cleaning technologies currently achieve about 30 to 50 percent reduction of *pyretic sulfur*, which is not chemically bound to the coal and has no impact on *organic sulfur* which is. This amounts to a reduction of about 10 to 30 percent reduction in the total sulfur. Conventional physical cleaning also cannot remove nitrogen impurities in the coal.

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[3] U.S. Environmental Protection Agency, *Renewable Electric Generation, An Assessment of Air Pollution Prevention Potential*, EPA/400/R-92005, March 1992, I-6, I-8.

Conventional postcombustion cleaning technology consists of the well known flue gas desulfurizers (FGDs) or "scrubbers." The basic technology consists of injecting limestone or other sulfur absorbing chemicals in a chamber to react with flue gases (Figure A-2). Two types of FGDs are currently in use. In wet limestone FGDs, a liquid slurry of water and limestone is injected into the reaction chamber. The SO_2 in the flue gases reacts chemically with the limestone reagent to form a wet sludge of calcium sulfite and calcium sulfate. Wet limestone scrubbers can achieve up to 95 percent SO_2 removal. Dry scrubbers use a slurry of finely atomized limestone or other sorbent. The droplets evaporate as they come into contact and react with hot gases and leave a solid waste. Dry scrubbers can achieve up to 90 percent SO_2 removal. Wet limestone FGDs are more effective on high sulfur coal typically found in the midwest, while dry FGDs work better on western low sulfur coal.

Conventional pollution control technologies usually fall short of achieving emission reductions required by the growing body of environmental regulations. As mentioned, conventional physical cleaning achieves only insignificant reduction of SO_2 emissions. Wet limestone FGDs introduce the problem of wet sludges that must be disposed of in large landfills.[4] While dry FGDs do not produce wet sludges, they are not as effective as the wet limestone designs in reducing SO_2 emissions from plants that use high sulfur coal.

The goals of the collaborative efforts to develop CCTs are to improve the effectiveness of precombustion and postcombustion cleaning and, also, to introduce new technologies based on the clean combustion concept.[5]

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[4] Over its lifetime, a 500 MW coal plant will produce enough sludge to fill a 500 acre disposal pond to a depth of forty feet, according to U.S. Department of Energy, *Clean Coal Technology, The New Era*, DOE/FE-0217P (Washington D.C.: U.S. Department of Energy, March 1992), 10.

[5] U.S. Department of Energy, *Clean Coal Technology Demonstration Program, Program Update 1991* (Washington D.C.: U.S. Department of Energy, February 1992).

Fig. A-2. Conventional coal-fired power plant with conventional flue gas desulfurizer (Source: Ohio Department of Development, *Ohio Coal Development Agenda*), 80.

Advanced Precombustion Cleaning Technologies

These technologies include improvements to physical separation techniques as well as chemical and biological cleaning. Physical separation can be significantly improved by crushing coal to much finer sizes than is usually done in conventional technologies and by employing new separation techniques. One such technique is electrostatic cleaning which exploits charges of opposite polarities on coal and mineral impurities to achieve separation. New physical separation techniques can remove more than 90 percent of the pyretic sulfur and other undesirable minerals from the coal.[6]

Physical separation techniques cannot remove organic sulfur that is chemically bound to the coal. Yet, organic sulfur comprises approximately 50 percent of the sulfur present in coal. Chemical and biological techniques that utilize chemical reactions and biological processes are currently being developed to achieve separation of organic sulfur from coal.

Molten caustic leaching is one of the chemical separation techniques that appears promising. The process consists of exposing the coal to a hot sodium- or potassium-based chemical. The chemical reacts with sulfur to form a sulfur compound which is then leached out. Other chemical techniques modify the chemical properties of coal in such a way that makes it more receptive to cleaning.

Biological techniques require less severe operating environments than chemical techniques. Researchers have identified naturally occurring bacteria that can digest the organic sulfur in coal. Other approaches involve using fungi, rather than bacteria, and injecting sulfur-digesting enzymes directly into the coal.

Chemical and biological techniques are potentially capable of removing as much as 90 percent of the total sulfur (both pyretic and organic) in coal.

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[6] Ibid., I-7.

Advanced Clean Combustion Technologies

This category of technologies include fluidized bed combustion and advanced or slagging combustion. Within each of these broad groups of technologies, various designs exist that achieve differing levels of SO_2 and NO_x reduction.

Fluidized Bed Combustion

Fluidized bed combustion reduces emissions by controlling combustion parameters (such as temperature) and introducing a sorbent in the combustion chamber. In a fluidized bed combustor (FBC), rather than blowing a cloud of small coal particles into the furnace (as in a pulverized coal plant), crushed coal mixed with limestone is suspended in a stream of up-flowing air (Figure A-3). The suspended particles form a fluid "bed," tumbling in a manner that resembles a boiling liquid. The limestone acts like a chemical "sponge," combining with the sulfur before it can escape the boiler and forming a solid waste of calcium sulfate and calcium sulfite. As in a conventional coal plant, heat is transferred in the boiler to water-carrying tubes to run a turbine.

Some of the solid waste is removed with the bed ash through the bottom of the boiler. Small ash particles, or fly ash that escapes the boiler, as well as unburned fuel and unreacted sorbent particles are entrained in the gases that escape the boiler. The fly ash and other particulates are captured with dust collectors. Depending on the design, the entrained solids may be recycled through the combustor from the dust collectors.

A coal plant equipped with FBCs has several advantages over the conventional plant. The waste generated is a reusable solid that presents fewer disposal problems. Also, the tumbling motion along with more intimate mixing of the coal with the air enhances combustion, and allows temperatures to be held at 1,400^{o}F to 1,600^{o}F, much below 3,000^{o}F, typically needed in a conventional plant. The lower temperature inhibits oxidation of nitrogen and formation of NO_x. Thus FBCs can meet both SO_2 and NO_x emission standards without additional pollution control equipment.

Fig. A-3. Atmospheric fluidized bed combustor (Source: Ohio Department of Development, *Ohio Coal Development Agenda*), 72.

Fluidized bed combustors also have other significant advantages over conventional combustors. Fluidized bed combustors are nonsensitive to coal feedstocks and work equally well with both high and low sulfur coal. They are also adaptable to coal plants of any size, making them attractive for repowering existing plants. While incremental capital costs of repowering may be higher than those of adding a conventional FGD, incremental operating costs are much lower. For example, an FGD is run by power drawn from the plant which reduces the plant's output and efficiency. An FBC contains no such parasitic energy loss. In some cases, the capacity of an aging boiler (whose capacity may have fallen below its rated value) can be enhanced by repowering it with an FBC.[7]

Fluidized bed designs can be classified according how the bed is maintained and operated (depending on the velocity of combustion gases and recycling of entrained solids) and also according to at what pressure it is designed to operate. Based on bed design, FBCs are generally classified as bubbling bed combustors or circulating bed combustors. Based on the operating pressure of the combustion gases, they are classified as the atmospheric fluidized bed combustor (AFBC) and the pressurized fluidized bed combustor (PFBC).[8]

Atmospheric Fluidized Bed Combustion

The AFBC operates at or near-atmospheric pressure (Figure A-3). Atmospheric fluidized bed combustors can achieve about 85 to 90 percent SO_2 reduction and moderate NO_x reduction. Plant efficiency remains the same. Power output can

[7] Ibid.

[8] More refined classifications are available based on latest advances in FBC technology. In this report, the description is limited to AFBC and PFBC.

increase by 10 to 15 percent owing to repowering of the steam cycle.[9] Plant life is also extended at moderate costs.

Pressurized Fluidized Bed Combustion

The difference between the PFBC and the AFBC is that the mixture of coal and limestone is suspended in flowing air and combustion gases at pressures six to sixteen times above the atmospheric pressure (Figure A-4). This allows the additional energy available in the high pressure gases to be used in a gas turbine. The dual operation of a steam and a gas turbine within the same plant is known as *combined cycle* operation. Such systems can boost power generating efficiencies to well above 40 percent, compared to about 30 to 35 percent typical achieved in a conventional coal plant. High pressure operation also allows smaller boiler units to be used to achieve the same power output. Slightly higher SO_2 reduction and a comparable NO_x reduction are achieved relative to the AFBC.[10] Other advantages include increase in plant efficiency, power output, and lower incremental costs.

Slagging Combustors

This combustion method is based on the *cyclone* concept. In a cyclone combustor, coal is burned in a separate chamber outside the boiler. The hot combustion gases then pass into the boiler (Figure A-5) and transfer heat to the water carrying tubes. This method keeps the ash out of the boiler chamber where it could collect on the tubes and degrade heat transfer efficiency. To keep ash from being blown into the boiler, the combustion temperature is kept so high that mineral impurities melt and form a *slag*,

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9 Ohio Coal Development Office, Ohio Department of Development, *Ohio Coal Development Agenda*.

10 Ibid.

Fig. A-4. Pressurized fluidized bed combustor (Source: Ohio Department of Development, *Ohio Coal Development Agenda*), 74.

Fig. A-5. Slagging combustor (Source: Ohio Department of Development, *Ohio Coal Development Agenda*), 76.

hence the name "slagging combustor." A vortex of air (the "cyclone") forces the slag to the outer walls of the combustor where the waste can be removed.

By improving heat transfer efficiency at the boiler, the emission of SO_2 per unit of energy output is reduced. To further reduce SO_2 emissions, limestone is injected into the combustor and/or the boiler. Because of high combustion temperatures, the older slagging combustors produced high levels of NO_x. To overcome this problem, advanced slagging combustors burn the coal in stages. Reductions of NO_x up to 80 percent can be achieved by these advanced processes.

Postcombustion Cleaning

Advanced postcombustion cleaning attempts to remove pollutants such as SO_2, NO_x and particulates more effectively than conventional scrubbers and at the same time overcome problems of plugging, corrosion and wet sludge production that plague the conventional technology. The advanced technologies pursue two basic approaches: *in-duct sorbent injection* and *advanced flu gas desulfurization*.

In-Duct Sorbent Injection

The clean up process in this system takes place inside the ductwork leading from the boiler to the smokestack (Figure A-6). Sulfur absorbers are sprayed into the center of the duct. The humidity and the spray pattern of the sorbent are carefully controlled to achieve SO_2 reduction between 50 and 70 percent. The reaction produces dry particles that can be collected downstream. To improve NO_x reduction, a small amount of natural gas is introduced above the normal heat release zone to form an oxygen deficient zone. The NO_x produced in the primary heat release zone is "reburned" in the oxygen deficient zone and partially reduced to molecular nitrogen.[11]

[11] Ibid.

Fig. A-6. Conventional coal-fired plant with in-duct sorbent injection (IDSI) and gas reburning (GRB) (Source: Ohio Department of Development, *Ohio Coal Development Agenda*), 78.

The system can be installed on the existing ductwork of a plant and does not require extensive new construction. This makes in-duct sorbent injection an attractive and low cost retrofit pollution control option, particularly for older and smaller plants that may not have enough space for installing new equipment.

Advanced Flue Gas Desulfurization (AFGD)

Advanced scrubbers, like their predecessors, place the flue gas processing facilities outside the main power plant (Figure A-7). Changes to the conventional system include modification of the scrubbing process, introduction of other chemical and electrochemical processes and use of additional reactor vessels. The new processes are designed to enhance sulfur removal, reduce other pollutants such as NO_x, produce reusable byproducts and eliminate the need for ancillary equipment such as reheating and backup modules.

In one application, the flue gas is bubbled through a lime slurry, thus reversing the conventional scrubbing process. This technique achieves higher levels of SO_2 reduction without the corrosion, plugging and scaling that occur with conventional scrubbers. Also, this process needs less energy to operate and produces reusable gypsum.

Another concept, extensively developed and being used commercially in Japan is *selective catalytic reduction* (SCR). In an SCR system, ammonia is mixed with flue gas and passed through a reaction chamber separate from the scrubber vessel. In presence of a catalyst, ammonia converts NO_x into molecular nitrogen and water. SCR systems are expected to reduce NO_x emissions by 50 to 80 percent and are currently being tested in the United States.[12]

Other advanced concepts may include new chemical absorbers. One such technique uses copper oxide, which converts SO_2 into copper sulphate that in turn converts NO_x into nitrogen when combined with ammonia.

[12] Department of Energy, *Clean Coal Technology*.

Fig. A-7. Integrated gasification combined cycle plant (Source: Ohio Department of Development, *Ohio Coal Development Agenda*), 84.

Coal Conversion

Coal can be converted to a fuel of another form prior to the combustion process. One commonly known technique is to convert coal to gaseous fuel. The cleaner burning gaseous fuel can then be used in an integrated gasification combined cycle (IGCC) plant to produce electricity. Other concepts under development include coal liquefaction and conversion of coal into a mixture of gases, liquids, and solids.

Integrated Gasification Combined Cycle

A particularly effective way to reduce emissions is to convert coal into a clean burning gas before injection into the boiler. This can be achieved by allowing coal to react with air and steam at a high temperature in a reactor vessel (Figure A-8). The coal converted to a gas composed predominantly of hydrogen, carbon monoxide, and hydrogen sulfide. The ash, which is not gasified, can then be easily separated. The sulfur in the coal is converted into hydrogen sulfide, which eventually can be converted to elemental sulfur or some solid waste material. The cleaned gas stream is combusted in the gas turbine. The combustion gases that exit the gas turbine can still be used to generate steam to run a steam turbine. The combined cycle operation can achieve up to 99 percent removal of sulfur and 40 percent or higher reduction of nitrogen emissions, moderate increase in efficiency (about 5 percent) and plant life.[13] Large increases in power output (50 to 150 percent) can also be achieved.

[13] One integrated gasification combined-cycle facility under construction (the Wabash River repowering project) under the auspices of the DOE's Clean Coal Technology Demonstration Project expects to have a heat rate of 8,740 Btu per kWh and to remove 98 percent of the sulfur in the coal to be consumed at the facility (*Electrical World* August 1993, 35).

Fig. A-8. Conventional coal-fired plant with advanced flue gas desulfurization (Source: Ohio Department of Development, *Ohio Coal Development Agenda*), 82.

Advanced Noncombustion Technologies

Two advanced concepts that have emerged recently and do not require coal combustion are *fuel cells* and *magnetohydrodynamics* (MHD).

Fuel Cells

Fuel cells use electrochemical reactions, rather than combustion, to generate electricity (and useable heat). The process is similar to that used in an ordinary electric battery. Fuel cells require electrochemical "fuels" in the form of hydrogen and oxygen, and an "electrolyte" that separates the electrodes (Figure A-8).

The most mature fuel cell concept is the *phosphoric acid* (the electrolyte) fuel cell. These cells have been used in hospitals, apartment buildings, and shopping centers and are now being developed for utility use. Another concept is the *molten carbonate* fuel cell, which uses a hot mixture of lithium and potassium carbonate as the electrolyte.

Magnetohydrodynamics

With MHD, a *plasma* of charged particles is created by burning coal at high temperatures (~5,000^{o}C). The electrical conductivity of the plasma is enhanced by seeding it with special salts, and the plasma is directed through an intense magnetic field (Figure A-9). The movement of an electrically conductive substance moving through a magnetic field generates electricity.[14]

The electricity generated in the MHD is tapped by electrodes embedded in the wall of the plasma channel. Additional electricity is produced by using the hot exhaust gases to run a conventional steam turbine achieving efficiencies up to 50 percent. The salts added to increase electrical conductivity also chemically react with sulfur released from coal, removing more than 99 percent of the sulfur. Nitrogen oxide is minimized by burning coal in stages in oxygen-deficient gas fuel mixtures.

[14] Ibid.

Fig. A-9. Fuel cell (Source: U.S. Department of Energy, *Clean Coal Technology, The New Coal Era* (Washington, D.C: U.S. Department of Energy, March 1992), 29.

Fig. A-10. Magnetohydrodynamics (Source: U.S. Department of Energy, *Clean Coal Technology*, 29.

Advanced Nuclear Technologies

Despite a promising start in the 1960s, nuclear power has since been confronted with rapidly rising operating costs, construction delays and cost overruns, and growing public concern over its perceived safety and environmental impact. Since the early 1970s, plans for building more than one hundred nuclear plants have ben either cancelled or deferred indefinitely. Negative public perception associated with nuclear technologies in general, unanticipated changes in the U.S. and world economies, and poor management may have all contributed to this development.

To restore nuclear power as a viable generating option, a movement has begun toward developing nuclear designs with better fuel economy, improved operation, and enhanced safety features. These advanced nuclear designs can be divided into three broad groups. The first two are improvements over the conventional light water reactors (LWRs) and also are called advanced light water reactors (ALWR). The two ALWR designs are categorized as "evolutionary" and "passive."[15] The evolutionary nuclear designs retain the basic configuration of the conventional LWR while enhancing its safety features. The passive designs, on the other hand, significantly modify the basic configuration so that there is less reliance on active components such as pumps and switches to ensure safety of the plant. Rather, there is more utilization of physical processes, such as gravity convection and evaporation to limit the development of a malfunction or accident. A third group of advanced designs uses a liquid metal or a high temperature gas as the coolant. To outline the features of the advanced nuclear designs, the conventional design is described first. The following section then presents three kinds of advanced design concepts.

[15] For a description of various evolutionary and passive designs, see various issues of *Nuclear News.*

The Conventional Nuclear Power Plant

The two most mature nuclear designs used in the United States, both of which are LWRs, are the pressurized water reactor (PWR) and the boiling water reactor (BWR). In a PWR, nuclear fission of uranium produces heat which is carried by pipes to a heat exchanger to boil water and produce steam. The steam is used to drive a turbine and produce electricity (Figure A-10). In a BWR, instead of boiling water in a heat exchanger, water is boiled in the reactor core itself where nuclear fission takes place (Figure A-11). In both designs, an emergency core cooling system consisting of pumps, valves, switches, and relays is used to detect malfunction-initiating events, activate safety equipment that shuts down the reactor, and flood the core with water to achieve further cooling.

The new designs attempt to improve several aspects of reactor operation including fuel economy, the heat transfer processes, and the safety system. Also, the new designs generally incorporate enhanced human factors engineering such as user-friendly control equipment and video displays.

Evolutionary Light Water Reactors

These designs achieve better fuel economy by modifying the fuel assembly configuration and the fuel composition. The modified fuel assembly also allows better access to the reactor core for refueling and maintenance work. Both the operation and the safety are enhanced by using state-of-the-art electronics in the control system, adding redundancy to safety equipment, eliminating certain equipment, and improving the ease and effectiveness of operator intervention.

Passive Light Water Reactors

These designs generally share many of the features of the evolutionary designs. In addition, passive designs attempt to minimize the reliance on active components (such as pumps) and operator intervention for both power production and safety functions. Instead, they rely on physical processes such as gravity, convection, and evaporation to make all malfunctions and accidents self-limiting. Also, passive designs are typically smaller (about 600 megawatts (MW) compared to about 1,200 MW typical of conventional and evolutionary LWR designs), allowing more modular capacity addition.

Other Advanced Designs

Other advanced designs do not use water as the coolant. They are improvements of conventional non-LWR designs such as liquid metal reactors (LMR) and high-temperature gas-cooled reactors (HTGR). The advanced liquid metal reactor (ALMR) and the advanced high-temperature gas-cooled reactors have the potential of producing much less radioactive waste than the ALWRs. They lack the operating history of LWRs available to ALWRs to draw upon, however.

Advanced Renewable Technologies

Renewable energy technologies are designed to convert natural processes into useful forms of energy (including electricity) without depleting natural resources. These technologies use the solar energy reaching the earth in its primary forms of heat and light or its transformed forms of wind, falling water, and organic matter. Other sources of renewable energy include gravity and the heat in the earth's interior.

Among the more mature renewable technologies are hydropower (use of falling water), hydrothermal (use of naturally occurring water or steam), and wind. Most of these technologies, except hydropower, are not yet economically competitive with more conventional fossil-based technologies for centrally dispatched large-scale utility-type applications. Current efforts are dedicated to improving the economy of renewable technologies.

Solar Thermal Electric Technology

Solar thermal electric power systems convert solar energy into electricity by first concentrating the incoming sunlight on a reflective surface and then converting it to heat and finally converting the heat into electricity. This process distinguishes this technology from photovoltaics (PV), which produces electricity from sunlight directly, without intermediate thermal conversion. There are three basic designs of solar thermal electricity: the central receiver, the parabolic dish, and the parabolic trough.

In a *central receiver* system, a field of computer-guided *heliostats* (mirrors) focuses sunlight onto a tower mounted receiver. The concentrated heat energy absorbed by the receiver is transferred to a circulating heat transfer fluid to power an electric generator. *Parabolic dish* systems use point-focusing collectors at the focal point of the parabolical concentrator. The collectors track sun in two axes and focus radiant energy onto a receiver at the focal point of the concentrator. Energy from a heat transfer fluid circulating through the receiver can be converted directly into electrical energy by using a heat engine/generator coupled to the receiver, or the thermal energy can be transported to a central location for conversion to electrical energy.

Parabolic troughs are U-shaped collectors lined with reflective material that concentrate sunlight onto a linear receiver tube positioned along the focal line of the trough. A fluid in the receiver is heated by the absorbed radiant energy and then transported to a central point for conversion to electric power.

The only commercial demonstration of solar thermal electric generation technology built in the United States was the 10 MW Solar One plant in Barstow, California. As a result of experience with Solar One, improved heliostats, receivers, and computerized controls are being developed. Current research and development efforts in solar thermal electric research are devoted toward developing improved reflectors, concentrators, receivers, storage systems, and conversion processes. For example, advanced receivers using molten salt or sodium as heat transfer fluids can potentially reduce receiver sizes by as much as 80 percent.

Solar Photovoltaic Electric Technology

Solar PV electric technologies (also called "photovoltaics") convert sunlight directly into electricity using thin layers of semiconducting material. The smallest unit of a PV system is a PV cell. Many different semiconducting materials can be used in cells; and two different approaches can be used for putting cells together into a module--flat plates and concentrators. A PV system is configured as a collection of modules. Modules can be designed to be fixed or tracking the sunlight to efficiently utilize variations of solar energy input. Current PV systems are used for dispersed (as opposed to central station) applications only. Current PV systems have efficiencies of 5 to 15 percent. Current research and development efforts are dedicated to improving the conversion efficiency and development of viable grid-connected (central station) applications.

Geothermal Electric Technology

The source of geothermal energy is the natural heat of the earth. The basic elements of a geothermal energy conversion system are: (1) the production well, through which the geothermal energy is conveyed to the surface; (2) the conversion system, which converts the geothermal energy to useful energy; and (3) the injection through which spent geothermal fluids are recycled back into the reservoir.

There are four kinds of geothermal resources: *hydrothermal*, *geopressured*, *hot dry rock*, and *magna*. Among these, hydrothermal technologies are the most developed and have been commercially used since 1960 in the United States. The other three technologies are in the initial stages of development.

Wind Energy Electric Technology

In the basic wind turbine, the energy contained in moving air masses is transferred to a rotating shaft. The shaft is connected to an induction motor to generate electricity. Over the last decade, there was a proliferation of wind turbine construction spurred by federal and state tax incentives that expired in 1985. These early installations experienced problems including low availability, equipment failures, and poor overall performance.

In spite of these early failures and the expiration of tax incentives, wind turbine construction generally expanded with concurrent improvements in technology that overcame many of the problems of first generation designs. First generation designs were rated at about 50 kilowatt and had a capital cost of $2,200 per kilowatt installed. Current designs, mostly developed in Europe, are about 300 kilowatt and cost between $1,000 per kilowatt and $2,000 per kilowatt. New wind technologies, known as the third generation, are being developed to achieve larger sizes, and at lower costs making it more competitive with other generation technologies.

Evaluating Generation Alternatives

Given the array of conventional and emerging generation technologies and the growing body of performance and environmental criteria to be met, utilities and other electric power producers are faced with complex choices in planning their systems. No study is currently known that evaluates and compares the various options on a comprehensive and standardized basis. Given the recent proliferation of decision variables and quantification problems associated with many of these variables, a standardized evaluation may not even be feasible.

In Tables A-1 through A-4, values of some of the more important decision variables/criteria are listed for a number of selected generation technologies. Since the information used in these tables was derived from sources a few years old, they may be somewhat outdated for certain innovative technologies. Consequently, the tables are presented for reference purposes only. The technologies listed include both conventional and emerging technologies. The data values have been compiled from different studies, which may vary with respect to underlying assumptions and methods. As such, the tables

TABLE A-1

COSTS OF SELECTED CONVENTIONAL AND INNOVATIVE TECHNOLOGIES*

Technology	Type ($/kW)	Capital Cost† ($/kW)	Levelized Life Cycle Cost† (¢/kWh)	Accuracy Range (percent)
Conv. Coal w Conv. FGD	Conv. Fossil	1,280-1,740	7.4-9.5	±10
GCC	Conv. Fossil	520-560	8.9-9.9	±15
Conv. Coal w Adv. FGD	CCT	1,480-1,590	7.9-8.2	±20
AFBC	CCT	1,600-1,720	8.7-9.4	±15
PFBC	CCT	1,460-1,570	~8.5	±30
IGCC	CCT	1,260-1,890	7.2-9.4	±15
Fuel Cells	CCT	1,110-1,480	8.2-16.8	±25
Evolutionary Nuclear Nuclear	Advanced ~1,520	~9.0	-30, +80	
Passive Advanced Nuclear Nuclear	~1,730	~9.1	-30, +80	
Solar Thermal/ Gas Hybrid	Renewable	~2,780	~19.3	0
Solar Photovoltaic	Renewable	2,420-2,640**	~18.7	-30, +100
Wind	Renewable	~1,010	~9.1	±15
Geothermal	Renewable	1,010-1,820	3.9-7.7	±10

Sources: Electric Power Research Institute, *Technical Assessment Guide*, Vol. 1, Rev. G, EPRI P-6587-L (Palo Alto, CA: Electric Power Research Institute, September 1989); and authors' calculations.

* The ranges reported represent the spread of average values among different designs of the same technology and do not represent the degree of statistical confidence. Accuracy ranges based on the degree of confidence are shown in the fifth column of the table. Some of the values shown for precommercial nuclear and renewable technologies reflect future targets set for advanced innovative designs. The current costs of renewables are much higher. **For example, the current capital costs of solar photovoltaic plants range between $6,500 to $9,000 per kilowatt**.

** See note under *.

† In December 1988 dollars. Capital costs have been rounded to nearest ten.

TABLE A-2

OPERATING CHARACTERISTICS AND PERFORMANCE OF SELECTED CONVENTIONAL AND INNOVATIVE GENERATION TECHNOLOGIES*

Generating Technology	Technology Type	Heat Rate** (BTU/kWh)	Conversion Efficiency (Percent)	Accuracy Range (Percent)	Load Duty Cycle
Conv. Coal w Conv. FGD	Conv. Fossil	9,640-10,044	33-36	±10	Base
Gas CT	Conv. Fossil	11,500-12,640	27-30	±15	Peak
GCC	Conv. Intermediate	Fossil	7,514-7,990	43-45	±15
Conv. Coal w Adv. FGD	CCT	9,080-9,420	37-39	±20	Base
AFBC	CCT	9,960-10,620	33-35	±15	Base
PFBC	CCT	8,980-10,280	34-39	±30	Base
IGCC	CCT	7,200-8,800***	35-38	±15	Base
Phos. Acid Fuel Cells	CCT	~8,550	~41	±25	Intermediate
Evolutionary Nuclear	Advanced Nuclear	10,530	~33	-30, +80	Base
Passive Nuclear	Advanced Nuclear	10,530	~33	-30, +80	Base
Solar Thermal/ Gas Hybrid	Renewable	3,300	N/A	0	Renewable
Solar Photovoltaic	Renewable	N/A	15-20	-30, +100	Renewable
Wind	Renewable	N/A	N/A	±15	Renewable
Geothermal	Renewable	21,870-29,000	10-16	±10	Renewable

Sources: Electric Power Research Institute, *Technical Assessment Guide*, Vol. 1, Rev. G, EPRI P-6587-L (Palo Alto, CA: Electric Power Research Institute, September 1989); and authors' calculations.

* The ranges reported represent the spread of average values among different designs of the same technology and do not represent degree of statistical confidence. Accuracy ranges based on degree of confidence are shown in the fifth column of the table.

** The reported heat rates are estimated annual averages. Values have been rounded to nearest ten.

*** One IGCC facility hosted by Tampa Electric Company and partially funded by DOE has a potential heat rate of around 7,200 Btu per kWh. The facility is applying a pressurized, air-blown, fixed-bed gasifier (*Electric World*, August 1993, 36).

N/A: Not applicable or not available.

TABLE A-3

ENVIRONMENTAL CHARACTERISTICS AND PERFORMANCE OF SELECTED CONVENTIONAL AND INNOVATIVE GENERATION TECHNOLOGIES

Generating Technology	Technology Type	SO_2 Emissions	NO_x Emissions	Greenhouse Gas Emissions	Waste Disposal
Conv. Coal w Conv. FGD	Conv. Fossil	Low; 90% reduction	High*	High	Ash, wet sludge
Gas CT	Conv. Fossil	Negligible	Moderate	Moderate	Negligible
GCC	Conv. Fossil	Negligible	Moderate	Moderate	Negligible
Conv. Coal w Adv. FGD	CCT	Low; 90% reduction	High*	High	Ash; nontoxic solid wastes
AFBC	CCT	Low; 90% reduction	Moderate; 70% reduction	High	Ash; nontoxic solid wastes
PFBC	CCT	Low; 90% reduction	Moderate	High	Ash; nontoxic solid wastes
IGCC	CCT	Low; 95% reduction	Low; 90% reduction	Moderate	Nontoxic solid wastes
Phos. Acid Fuel Cells	CCT	Low	Low	Low	Negligible
Evolutionary Nuclear	Advanced Nuclear	None	None	None	Radioactive wastes
Passive Nuclear	Advanced Nuclear	None	None	None	Radioactive wastes
Solar Thermal/ Gas Hybrid	Renewable	Low	Low	Low	Heat transfer fluid (HTF) waste
Solar Photovoltaic	Renewable	None	None	None	Heavy metals waste at decommissioning
Wind	Renewable	None	None	None	Negligible
Geothermal	Renewable	None	None	None	Negligible

Sources: Ohio Department of Development, *Ohio Coal Development Agenda, 1992*; U.S. Department of Energy, *Clean Coal Technology Demonstration Program, 1992.*

* Without additional NO_x controls.

TABLE A-4

DEPLOYMENT POTENTIAL OF SELECTED INNOVATIVE GENERATION TECHNOLOGIES

Generating Technology	Technology Type	Unit Size Modularity	Fuel Flexibility	Retrofit/ Repower Potential	Development/ Commercialization Status
Conv. Coal w Adv. FGD	CCT	N/A	Poor	High	Nearly mature
AFBC	CCT	Moderate	High	Moderate	Nearly mature
PFBC	CCT	Moderate	High	Moderate	Immature
IGCC	CCT	N/A	High	Moderate	Immature
Fuel Cell	CCT	High	N/A	N/A	Immature
Evolutionary Nuclear	Advanced Nuclear	Poor	N/A	N/A	Immature
Passive Nuclear	Advanced Nuclear	Moderate	N/A	N/A	Immature
Solar Thermal/ Gas Hybrid	Renewable	High	Low	N/A	Nearly mature
Solar Photovoltaic	Renewable	High	N/A	N/A	Advanced technologies Immature
Wind	Renewable	High	N/A	N/A	Advanced technologies Immature
Geothermal	Renewable	High	N/A	N/A	Advanced technologies Immature

Sources: Authors' review of technical literature.

N/A: Not applicable or not available.

may not represent an objective and accurate basis for comparing the potential merits of the various technologies. The data included in the tables are intended to provide a broad overview, and *approximate* and *qualitative* comparison between various technology options.

The evaluative criteria may be classified into four broad groups. They are cost (Table A-1), operating characteristics (Table A-2), environmental performance (Table A-3), and deployment potential (Table A-4).

Cost

Based on cost data alone, most of the new technologies appear generally competitive to conventional fossil technologies. The only exceptions are the fuel cell and the solar technologies, which have significantly higher costs than other technologies. The data on fuel cell are based on the phosphoric acid design. With new fuel cell technologies, such as the molten carbonate design, drastic cost reductions are expected (to about 8 cents per kWh) to make it competitive with the other options. Solar technologies also need to achieve significant cost reductions to compete with other alternatives.

Operating Characteristics and Performance

The attractiveness of an IGT will depend significantly on its operating performance relative to conventional technologies. Table A-2 summarizes the operating characteristics of selected conventional technologies and IGTs. From the table, it is observed that the CCTs under development generally have superior efficiencies relative to conventional coal plants. One of the conventional fossil technologies, namely the gas combined cycle (GCC), appears to have the best conversion efficiency (~50 percent) because of its dual cycle capability and the fact that it is a well-developed technology. The GCC is likely to be the choice of most utilities for near-term capacity additions.

The conversion efficiencies of renewables are generally inferior compared to fossil-based and nuclear technologies. This comparison is not very useful, however, because of the differences in the resources used by the different groups of technologies. Within the renewable technologies, solar thermal has the best efficiency.

Environmental Performance

Environmental performance is likely to be a very important criteria that will influence the technology choice of utility decisionmakers in the coming years. The Clean Air Act Amendments of 1990 (CAAA) imposed very stringent restrictions on the emission of SO_2, NO_x, and other air pollutants. Although no regulation of CO_2 and other greenhouse gases emissions is included in the CAAA, it is likely that new legislation in the foreseeable future will be enacted to curb these emissions as well. Utility planners, therefore, need to account for the possibility that the emission of greenhouse gases will be regulated in the future. Finally, waste disposal presents a formidable problem for utilities using conventional fossil-based technologies as they must comply with federal and state land-use and water quality regulation.

From Table A-3, it is clear that the CCTs and conventional gas turbines are clearly superior to conventional coal-based technologies. Even when a conventional scrubber is included, conventional coal-based plants do not offer any effective controls for NO_x emissions. While most of the CCTs offer significant reductions of both SO_2 and NO_x, when employed as retrofit technologies, they involve high retrofit costs compared to conventional FGD.

All fossil-based plants emit CO_2 and other greenhouse gases. Technologies that use natural gas in combined cycle operation, however, emit significantly lower levels of greenhouse gases. The renewable technologies are relatively free from air pollutants, as are nuclear options. Both renewable and nuclear options, however, can have other potential environmental impacts.[16]

Deployment Potential

Besides cost, operating characteristics, and environmental performance, other important factors exist that will affect the technology choices of utilities. They include unit size modularity, fuel flexibility, construction time, retrofit/repower potential, and development/commercialization status. Together, these factors contribute to the deployment potential of a technology. Figure A-4 shows a compilation based on estimated data.

Because utility planners are increasingly cognizant of the uncertainty of planning parameters, they are likely to favor options which offer flexibility. Small unit sizes that offer modular additions of capacity are likely to be chosen over options that involve large additions of capacity. Most of the new CCTs under development have this feature. In addition, they offer flexibility of fuel choice unlike their conventional counterparts.

Construction time (not listed in Table A-4) is another parameter that is likely to affect the technology choice. The utility industry's unfavorable experience with construction delays and cost overruns is likely to predispose utilities toward generating technologies with shorter construction times. Technologies that offer size and fuel flexibility also have generally short construction times. Most CCTs and renewables have these features. The only exception may be nuclear, which traditionally has experienced the longest construction delays. With the streamlining of the licensing process under EPAct, construction times are expected to be shortened from the historical ten to fifteen years to five to six years. If this happens, the competitiveness of the nuclear options will also improve.

Finally, development status and commercial readiness is one of the most important

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[16] Renewable power installations can significantly alter the local natural environment and ecosystems because of their generally large sizes. A nuclear plant, which generates almost no pollutants during normal operation, can release hazardous levels of radioactive materials during a malfunction or accident.

parameters that will affect utility technology choices. Generally speaking, most CCTs are in more advanced stages of precommercial development than the renewable options. This is presumably because of the fact that CCTs have a richer body of operating experience than the other options to draw upon.

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APPENDIX B

FIRMS, MARKETS, REGULATION, AND INNOVATION: A BACKGROUND DISCUSSION

To examine the adoption of innovative generation technologies by power producers in a regulated environment, it is useful to review the innovative process in the general context of a profit-driven activity.[1] Innovation, either in a free market or in a regulated setting, is governed by the presence of common factors that may facilitate or impede its adoption and diffusion. They include, among others, risks, profit opportunities, market structure and size, firm size and current state of technological knowledge. Among these, risks and profit opportunities may be considered primary factors that drive innovation. The other factors generally affect innovation through their influence on risks and profit opportunities. Also, these factors are not necessarily exogenous since they are affected by innovation as much as they affect innovation.[2] For example, a competitive market structure may motivate innovation and a successful innovation, in turn, may earn higher market share for the innovator and thereby reduce the level of competition.

Determinants of Innovation in A Competitive Market

Risk

Innovation in any form carries risks. Innovation generally involves invention, development and commercialization of a new product or process. At every stage of the

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[1] In economic literature, two categories of innovation are recognized: the technology push hypothesis emphasizes the role of underlying scientific knowledge; the demand pull hypothesis, on the other hand, holds that innovation is primarily driven by economic opportunity. For a comprehensive review of economic literature on innovation, see Morton L. Kamien and Nancy L. Schwartz, *Market Structure and Innovation* (Cambridge, MA: Cambridge University Press, 1982).

[2] To simplify the discussion, this chapter is limited to a review of effects of various factors on demand-pull or profit-driven innovation.

innovative process, the new product or process may not perform according to expectations. Invention at the laboratory scale may involve many failed experiments before a useable design or concept achieves scientific viability. At the pilot scale, the size and other parameters of the product may have to be changed and may fail to perform under the new configuration, requiring redesign before the product can achieve engineering viability. Prototype testing and demonstrations may reveal even additional flaws that have to be corrected. Finally, commercialization, besides revealing additional technical flaws, exposes the product to a host of market and financial risks. Some of these risks include unanticipated construction delays and cost overruns, inability to obtain the required financing to fund the construction, initial operating failures after successful construction, and failure of the expected demand for the product to materialize. Competition from rivals represent another source of risks. Rivals may be engaged in innovative activities themselves and may be able to successfully commercialize a product superior to the innovator in question. Absent patent protection, rivals may also be successfully able to imitate the product at lower costs and sell it at lower prices than the innovator and thereby gain a market advantage.

The presence of various risks have important motivating influences on the innovator. A product may have to be dropped entirely in any one of the stages of development if it turns out to be not viable. This may represent a large sunk cost to the innovator that cannot be recovered. Even in the case of successful innovations, large uncertainties associated with the costs of development exist. The revenues and profits that could be earned by the new product are also uncertain and may not adequately compensate the innovating firm for its development costs. Therefore, a firm will only innovate if it is willing and able to bear the risks of innovation.

Willingness to bear risks reflect the risk attitude of the firm. Risk-taking firms generally assume higher risks for higher expected returns. Risk-averse firms, on the other hand, by preferring low-risk ventures, are willing to accept lower returns. Regardless of its risk attitude, every firm will devote considerable effort to reduce its risk exposure. Opportunities to shift or diversify risks improve a firm's ability to bear risks.

Both the risk attitude and ability to bear risks are affected by such factors as firm size, market size and structure and the characteristics of the innovative product.

Profit Opportunities

Opportunities for increasing profits are a primary motivator for innovation. Innovation may either create a new product to meet an unmet demand or lower the cost of producing an existing one. Benefits of a successful innovation to an individual firm include increasing market share and driving out competitors. A new firm may be able to gain entry into a market and an existing firm may be able to bar entry by others through innovation. Monopolies threatened by entry may be able to erect barriers to new entrants into the market through innovation. Monopolies, not threatened by competition, may be able to lower prices through cost-reducing innovations and increase sales. In each of these cases, innovation either preserves above-normal profits (involving monopolies) or increases profits (involving competitive firms). Only when a firm expects to be compensated adequately for bearing risks will it engage in innovative activity.

Firm Size

The size of a firm has a significant bearing on whether an innovative activity will be pursued. Larger firms usually have greater resources to finance research and development (R&D) activities than smaller ones. Often the R&D will have scale economies such that innovative efficiency may require either mergers or joint ventures.[3] Also, larger firms are better able to diversify risks than smaller ones. Schumpeter (1943) observed that large firms or those with monopoly power are more likely to innovate.[4] Later refinements in theory and empirical evidence,

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[3] Sanford V. Berg and John Tschirhart, *National Monopoly Regulation: Principles and Practice* (Cambridge, MA: Cambridge University Press, 1988), 390.

[4] J. A. Schumpeter, *Capitalism, Socialism, and Democracy* (New York: Harper and Rose, 1943).

however, did not always agree with this conclusion.[5] One reason for this discrepancy is that it does not distinguish between different kinds of innovations. It is more reasonable to conclude that both large and small firms play essential, complementary and interdependent roles in the innovation process. Larger firms tended to contribute most in innovations requiring large scale R&D, production, or marketing. Smaller firms tend to concentrate on specialized but sophisticated components and equipment that require small investments.

Market Structure

As mentioned, the earliest work on innovation and market structure by Schumpeter claimed that monopolies rather than competition were more conducive to innovation.[6] Some of the later studies supported this claim while others refuted it. One weakness with most of these studies is that they do not distinguish between R&D competition and competition in actual product market. Firms specializing in R&D for grants and loans may have lower risks and investment than those intending to market the ultimate product. Based on an extensive review of studies in this area, Kamien and Schwartz (1982) conclude that a market structure intermediate between monopoly and perfect competition would probably promote the highest rate of innovative activity.[7]

Technology Attributes

Attributes of the firm and the market alone do not determine the level of innovative activity. It is the complex interaction between the attributes of firms, markets,

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[5] F. M. Scherer, "Size of Firm, Oligopoly, and Research: A Comment," *Canadian Journal of Economics and Political Science* 31 (1965), 256-66.

[6] Schumpeter, *Capitalism, Socialism, and Democracy*.

[7] See Kamien and Schwartz, *Market Structure and Innovation*.

and technologies that will determine the development and commercialization of a given technology.

The preceding sentence suggests an important attribute of a technology that may decide whether it will find a developer or adopter: the stage of development. At the conceptual or laboratory stage, the performance of the proposed technology is highly uncertain; but the capital outlays are small. At this stage, research laboratories or universities are the most likely institutions to engage in inventive activity. Once the basic concept has been successfully tested, pilot or demonstration scale test may be made. Developers and equipment vendors have played a key role at this stage. At the commercial deployment stage, where investments and risks significantly increase, firms associated with the ultimate product take over.

As different firms or entities are involved in different stages of innovation, their risks and profit opportunities also vary. It is much easier to abandon a failed concept at the laboratory stage than a fully constructed facility at a utility site. Also, firms specializing in different aspects of product development are subject to different market and regulatory environments. In the example of the electric utility industry, research laboratories, component manufacturers, equipment vendors, developers, and construction companies fall outside the purview of state regulation. In each of these specialized markets, competition will generally influence the innovative process. The electric utility industry, subject to rate-of-return regulation, on the other hand, will have different incentives for innovation than the other industries mentioned. All the input supplies for the electric power industry, however, are indirectly affected by the utilities' posture toward innovation. If there is no demand for innovation at the utility level, this will ripple through and dampen incentives for innovation in other market segments of the industry. So, the incentives for electric utilities under a regulatory environment have important implications for innovative activity throughout the entire electric industry.

Innovation in a Regulated Environment

The determinants of innovation are significantly changed by the introduction of a regulatory process. Firms subject to economic regulation are usually natural monopolies. Unlike firms operating in competitive or contestable markets, they are not threatened by the possibility of new entrants and are less vulnerable to this source of risk.[8] While this has a risk-reducing effect, regulation introduces new risks. Regulation also changes the profit opportunities in important ways.

The Effects of Regulation on Risks

One key feature of firms subject to economic regulation are retrospective disallowances. Investments in capital plant and equipment are subject to *ex post* prudent and "used and useful" reviews. Prudence reviews can disallow earnings from investments by their exclusion from rate base if it is determined that they were made imprudently based on contemporaneous circumstances. Although in principle, *ex post* reviews are not based on hindsight or final outcomes, the influence of hindsight in arriving at final determinations of prudence cannot be entirely denied. In its more stringent form, prudence reviews apply a "used and useful" test that may disallow an investment based on its usefulness *ex post*, regardless of whether initial decisions were prudent or not.

The exercise of *ex post* reviews can exacerbate the risks inherent in innovation. It can be argued that such reviews, especially "used and useful" reviews, are analogous to a market test and that a market also penalizes poor outcomes. Yet, the decision making processes in a market setting and a regulated setting are entirely different. A market, particularly the financial market, responds to a new investment much earlier, based on its evaluation of the investments' potential to earn profits. This allows firms to discontinue or abandon projects at their initial stages if the early market response is not favorable, at relatively low sunk costs. In a regulated setting, a firm has to

[8] While electric distribution and transmission continue to be monopolies, there is growing competition in the electric generation sector.

wait much longer before such a determination can be made. Further, the final fate of a project, which is usually influenced by the adversarial intervention process that reflects the preferences of various interest groups, may not reflect the preferences of the ultimate consumer as it would be the case in a free market. This distorts the character of risk in a regulated setting relative to a free market. Specifically, it may have a negative effect on innovative technologies, which are generally riskier than the conventional alternatives.

Ex post reviews exist, however, because they are needed to ensure efficient management. Without prudence reviews, the management of a utility may not exercise the necessary effort and prudence to ensure efficient decisionmaking and operations. The question remains whether current regulation achieves the right balance, in terms of promoting consumer interests, between ensuring efficient management and promoting optimal risk-taking.

Regulation, Expected Returns, and Profit Opportunities

Regulated utilities are generally subject to limits on the rate of return on investments. This means that the firm is not rewarded with above-normal profits, one of the major motivations for innovation in a free market, for risk-taking.

Two sources of short-term supernormal profits exist in a free market. First, a cost-reducing innovation allows a firm to appropriate the cost savings on a per unit basis from its existing market. Second, innovation, with a slight reduction of price below the existing market price, may expand the sales of the firm and add to its revenue stream. Neither opportunity is generally available for a regulated firm. Cost reductions, achieved as a result of successful innovation would mostly be passed on to ratepayers with little or no gain to the innovating firm. The corresponding decline in rates may attract new customers; but the regulatory commission, not the firm, has the ultimate discretion on setting rates for different classes of customers. If the cost-savings are passed on mostly to the price-inelastic customers, it is unlikely that there will be any significant increases in revenue streams. While utility commissions may allow a utility to offer promotional rates to new businesses to locate in its service territory, it is not usually tied to cost savings achieved through innovation and good management. The only exception to the argument may be the presence of regulatory lag, which allows a utility to retain its cost savings until the next rate hearing. But it is not clear whether this presents a sufficient incentive for cost-reducing innovations, especially for those with a long payback period.

A rationale exists for requiring cost-reductions achieved by a utility management to be passed on to ratepayers: a utility is granted a monopoly franchise in exchange for least cost and reliable service to its customers; in view of this compact between customers and the utility, the utility does not have the same rights as an unregulated firm to appropriate the savings it achieves through innovation and good management. Consequently, the current regulatory arrangement may not provide additional rewards for the extra effort expended on innovative activities. One approach that could benefit ratepayers and at the same time reward the firm for innovation is to allow the sharing of potential savings.

Innovation, Externalities, and Public Goods

One of the reasons that may discourage firms from engaging in innovation is its appropriability. A successful innovation is open to imitation by rivals of the innovator. This can generally be done at costs lower than the development costs incurred by the innovator. This allows the rivals to undercut the innovator in the market by offering lower prices. Thus the innovation has a positive externality for the rivals of the innovator. The presence of this externality or free rider problem may discourage innovation.

Yet, the innovation may have a positive externality for society at large: the product can potentially be available for consumption at lower prices. In other words, the social returns from innovation may be higher than the private returns of the innovator.[9]

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[9] Jean Tirole, *The Theory of Industrial Organization* (Cambridge, MA: MIT Press, 1989), 391.

If this is true, the innovation assumes a public good character. Therefore, it may be appropriate for society to compensate the innovator for this externality.

Possible ways of compensating the innovator are through patent protection, grants, loans, tax subsidies and favorable regulatory treatment. Based on the nature and the scope of the externality, it may be appropriate for various public agencies and government institutions to compensate firms for the efforts expended and risks borne in pursuing innovations. For regulators, incentives may take the form of mechanisms that reward risk-taking and allow a firm to retain cost savings from innovations. It may also involve reforming regulatory practices that may present barriers to innovation.

Adoption of Innovative Generation Technologies and the Role of Economic Regulation

As discussed (see Chapter 1), innovative generation technologies have clear public benefits. They include such national values as energy security and environmental quality as well more local and state level benefits such as a cleaner local environment and job protection. While conflicts may exist among these interests, which may favor one technology over another (coal-based technologies may be favored in coal-rich states), the deployment of innovative technologies, regardless of fuel or resource type, may better serve all interests and may even reduce the level of conflicts. Clean coal technologies, for example, may achieve a better environment (a national and local goal), lower generating costs (a commission goal), and preserve jobs in high sulfur coal states (a local goal) relative to conventional coal-fired and pollution control technologies.

The kind and level of support needed for developing and deploying IGTs depend on the interests affected and the jurisdiction and mandates of public institutions able to offer support. Current support for developing and demonstrating IGTs comes from the Department of Energy, which is jointly funding a large number of projects with participation from the Electric Power Research Institute (EPRI), developers, equipment vendors, and component manufacturers. Support is also available from state governments in the form of tax subsidies for various generation and pollution control technologies for both development and commercialization.

As each of the technologies reaches commercial readiness, its commercial deployment will depend critically on the role of commission regulation. As in the case of other government institutions, it may be appropriate for commissions to offer incentives to utilities for deployment as long as doing so is consistent with the basic mandate and objectives of public utility regulation. The manner in which such incentives are offered also must comport with the commission mandate. One approach would involve removing regulatory barriers to innovation, if it can be shown they exist. As discussed in this report, current features of commission regulation may not favor the deployment of new technologies. To the extent commissions are responsible for ensuring least cost supplies of electricity to ratepayers while promoting other state objectives, a reexamination of current regulatory practices may be in order. The objectives of such an examination would be to investigate the presence of regulatory barriers to the adoption of innovative generation technologies and whether they represent efficient or inefficient barriers. To the extent they represent inefficient barriers, one can explore approaches that mitigate such barriers and promote more efficient technology choices for the generation of electricity.

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APPENDIX C

SELECTION OF SIMULATION PARAMETERS

Data supporting the particular parameterization chosen are as follows. The average generating capacity of a coal plant built between 1980 and 1982 was 511.4 megawatts (MW).[1] On average, coal plants consumed .985 pounds of coal per kilowatthour (kWh) generated in 1988, and in that year coal cost an average of $32 per ton.[2] Thus, the average cost of fuel per kWh of electricity generated by a coal-fired plant was $0.01576.

If operated continuously for 8,760 hours per year, a 1 MW plant would produce 8.76 million kWh per year. Taking into account reserve margins and operating outages, 1 MW of generating capacity produces on average only 3.747 million kWh per year.[3] Thus, an average-sized coal-burning plant of 500 MW capacity generally produces about 1.875 billion kWh per year of electricity, and consumes 0.923 million tons of coal in the process. One homothetic production function that is consistent with the above information is $Q(K,L) = (.01709^{.75}L^{.25})^{1.1} = .01138K^{.825}L^{.275}$.

The demand function can be calibrated to the above data as well. If a typical consumer uses about 20,000 kWh per year, a 500 MW plant could supply electricity for about 93,750 homes. Suppose that the price of electricity is $0.05 per kWh, and that at this price demand is exactly 1.875 billion kWh per year. Suppose that demand is rather inelastic, so that $\epsilon = -0.5$.

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[1] Paul L. Joskow and Richard Schmalensee, "Incentive Regulation for Electric Utilities," *Yale Journal on Regulation* 4, no. 1 (Fall 1986), 50.

[2] Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry 1988*, no. 56 (Washington, D.C.: Edison Electric Institute, November 1989), 33, 35.

[3] Ibid., 22.