SR/OIAF/95-01
Distribution Category UC-950

An Analysis of Nuclear Power Plant Operating Costs: A 1995 Update

April 1995

Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, DC 20585

Service Reports are prepared by EIA upon special request and may be based on assumptions specified by the requester. Information regarding the request for this report is included in the Preface.

Contacts

This report was prepared by the Nuclear and Electricity Analysis Branch, Energy Supply and Conversion Division, Office of Integrated Analysis and Forecasting. General questions regarding this report may be addressed to Mary J. Hutzler, Director, Office of Integrated Analysis and Forecasting (202-586-2222); Scott Sitzer, Director, Energy Supply and Conversion Division (202-586-2308); or Robert T. Eynon, Chief, Nuclear and Electricity Analysis Branch (202-586-2315). Specific questions should be addressed to James G. Hewlett, Project Manager and principal analyst (202-586-9536, E-Mail jhewlett@eia.doe.gov).

Preface

Section 205(a)(2) of the Department of Energy Organization Act of 1977 (Public Law 95-91) requires the Administrator of the Energy Information Administration (EIA) to carry out a central, comprehensive, and unified energy data and information program that will collect, evaluate, assemble, analyze, and disseminate data and information relevant to energy resources, reserves, production, demand, technology, and related economic and statistical information. To assist in meeting these responsibilities in the area of electric power, EIA has prepared this report, *An Analysis of Nuclear Power Plant Operating Costs: A 1995 Update*.

The primary purpose of this report is to provide an updated analysis of nuclear power plant operating costs. This is the third report on this subject published by EIA since 1988. This work was done at the request of the U.S. Nuclear Regulatory Commission, using data and methodologies deemed by EIA to be appropriate.

The legislation that created EIA vested the organization with an element of statutory independence. The EIA does not take positions on policy questions. The EIA's responsibility is to provide timely, high quality information and to perform objective, credible analyses in support of the deliberations by both public and private decisionmakers. Accordingly, this report does not purport to represent the policy positions of the U.S. Department of Energy or the Administration.

Contents

Tables

Figures

1. Introduction

This report is the second update to the 1988 report, *An Analysis of Nuclear Power Plant Operating Costs*.[7] Non-fuel operating costs consist of operating and maintenance (O&M) costs, which are mainly labor to run and maintain the plant, and capital expenditures incurred after the plant entered commercial operation (capital additions). Capital additions are expenditures for major repairs and replacements of equipment, or plant modifications required by the U.S. Nuclear Regulatory Commission (NRC) or implemented by utilities at their discretion. The 1988 report found that real (inflation-adjusted) O&M and capital additions costs escalated at annual rates of 12 percent and 17 percent, respectively, over the 1974-1984 period. The first update, published in 1991, found that the escalation in real O&M costs fell to less than 5 percent from 1984 to 1989, and the level of capital additions actually fell.[8]

The 1988 and 1991 reports also described the results of a statistical analysis that attempted to determine the factors causing the escalation in O&M and capital additions costs. Both analyses found that an increase in NRC regulatory actions was the major factor causing the escalation in O&M costs. However, these regulation-induced cost increases were partially offset by strong learning effects that caused O&M costs to fall. The escalation in capital additions costs was the result of increases in NRC regulatory requirements and plant aging.[9]

According to the conventional wisdom, nuclear power plants are expensive to construct but very inexpensive to operate. Because of this perception of low and predictable operating costs, nuclear power plants were expected to operate until the failure of a life-limiting component (e.g., reactor vessel or containment.) Since these components were designed to last for 50 to 60 years, nuclear power plants were expected to operate for at least 40 years. However, with the escalation in O&M costs, it is not clear whether nuclear power plants will operate as long as was previously thought. Indeed, over the past few years three nuclear power plants with ages between 17 and 31 years were retired because the owners and associated regulatory authorities deemed that capital expenditures to replace (or modify) plants components were uneconomical. According to the Office of Technology Assessment of the U.S. Congress (OTA), at current levels most nuclear power plants are moderately attractive. However, OTA also found that the "long term prospects for the Nation's . . . operating nuclear power plants are increasingly unclear," and additional substantial cost increases could threaten the economic viability of many units.[10]

Consequently, the industry now views the escalation in O&M costs as a major challenge and realizes that O&M cost containment is crucial to the continued economic viability of many operating power plants. As a result, over the past few years, the industry has undertaken a number of steps to reduce O&M costs, including: controlling contractor expenses; upgrading to more efficient technology; controlling the use of overtime; and identifying and stopping unnecessary work.

Additionally, in the 1980s, the NRC also took actions to control the growth in regulations. First, in 1988 the NRC initiated procedures to limit the number of backfits. Backfits are NRC-required changes in the design of the plant, which affect capital additions and perhaps O&M costs as well. Additionally, over roughly the same time period, the NRC attempted to improve the efficiency of the regulatory process. The intent was to achieve the same level of safety at lower cost. For example, the NRC developed a set of indicators that

[7]Energy Information Administration, *An Analysis of Nuclear Power Plant Operating Costs*, DOE/EIA-0511 (Washington, DC, 1988).

[8]Energy Information Administration, *An Analysis of Nuclear Power Plant Operating Costs: A 1991 Update*, DOE/EIA-0547 (Washington, DC, 1991).

[9]These results are also consistent with many industry studies. For a review of these studies see Energy Information Administration, *An Analysis of Nuclear Power Plant Operating Costs: A 1991 Update*, DOE/EIA-0547 (Washington, DC, 1991); Energy Information Administration, *World Nuclear Outlook*, DOE/EIA-0436(94) (Washington, DC, December 1994); and Nuclear Management and Resources Council, *Review of Operations and Maintenance Costs in the Nuclear Industry* (Washington, DC, December 1992).

[10]See Energy Information Administration, *World Nuclear Outlook*, DOE/EIA-0436(94) (Washington, DC, December 1994); U.S. Congress, Office of Technology Assessment, *Aging Nuclear Power Plants: Managing Plant Life and Decommissioning*, OTA-E-575 (Washington, DC, 1993); and James G. Hewlett, "The Economics of Aging U.S. Nuclear Power Plants," in *The Nuclear Industry: Into the 21st Century* (London, United Kingdom: Financial Times of London, 1994).

reflect the overall safety of the plant. These indicators are used by the NRC to focus their regulatory efforts on the poorer performing plants.[11] These actions should affect O&M costs.

As discussed later in this report, over the past few years real (inflation-adjusted) O&M costs have begun to level off. The objective of this report is to determine whether the industry and NRC initiatives to control costs have resulted in this moderation in the growth of O&M costs. Because the industry agrees that the control of O&M costs is crucial to the viability of the technology, an examination of the factors causing the moderation in costs is important.

A related issue deals with projecting nuclear operating costs into the future. Because of the escalation in nuclear operating costs (and the fall in fossil fuel prices) many State and Federal regulatory commissions are examining the economics of the continued operation of nuclear power plants under their jurisdiction.[12] The economics of the continued operation of a nuclear power plant is typically examined by comparing the cost of the plant's continued operation with the cost of obtaining the power from other sources. This assessment requires plant-specific projections of nuclear operating costs.

Analysts preparing these projections look at past industry-wide cost trends and consider whether these trends are likely to continue. To determine whether these changes in trends will continue into the future, information about the causal factors influencing costs and the future trends in these factors are needed. An analysis of the factors explaining the moderation in cost growth will also yield important insights into the question of whether these trends will continue.

The organization of this report is as follows: Chapter 2 discusses the historical trends in O&M costs and tabulations of causal factors. Since operating costs are influenced by more than one causal factor, simple cross-tabulations can give misleading information about the direction and size of these factors. To avoid this problem, a structured statistical analysis was undertaken as described in Chapter 3. Chapter 4 presents the results of an analysis of the factors causing the change in the trends in operating costs and whether the industry and NRC initiatives to reduce O&M costs caused the trends to change.

[11]See U.S. Nuclear Regulatory Commission, *Annual Report to Congress*, NUREG-1145, Vol. 10 (Washington, DC, 1990).

[12]See, for example, U.S. Congress, Office of Technology Assessment, *Aging Nuclear Power Plants: Managing Plant Life and Decommissioning*, OTA-E-575 (Washington, DC, 1993).

2. Description of Operating Cost Data and Trends in the Data

The data on nuclear power plant operating costs used in this analysis were obtained from Schedule 402 of the Federal Energy Regulatory Commission (FERC) Form 1, "Annual Report of Major Utilities, Licensees and Others." These data have been published by the Energy Information Administration (EIA), the Federal Power Commission, and several private firms (e.g., Utility Data Institute) since the 1950s. Although the data are widely used, there are issues concerning the coverage and definition of operating costs. Therefore, this chapter begins with a discussion of the operating cost data used in the analysis and the definitional issues. This chapter then presents some trends in the data and discusses the three principal factors thought to influence operating costs. Some of these trends suggest relationships found in the statistical analyses described in Chapter 3.

Nature and Sources of the Operating Cost Data Used in the Study

The operating cost data used in the study are divided into two categories. Those nonfuel operating costs that are expensed for ratemaking purposes are called O&M costs, while those nonfuel operating costs that are capitalized are called "capital additions." The types of costs that are expensed and capitalized are to some extent specified by law in the Uniform System of Accounts.[13]

A recently completed study has estimated that approximately 67 percent of the total reported O&M costs are labor related, and the remaining 33 percent are for expenditures on maintenance materials and supplies. It has been estimated that for a typical 1,000-megawatt plant, about 47 percent of the staff performs maintenance and support activities. Power plant operators comprise about 16 percent, and security workers about 17 percent of the total on-site staff. Most of the remaining 20 percent perform various administrative and managerial activities. Thus, the reported O&M costs consist mainly of labor expenses, with the largest single component representing maintenance activities.[14]

There are three types of post-operational capital expenditures (i.e., capital additions). First, there are the major plant retrofits that are required by the NRC. An example of such a retrofit would be the NRC-mandated redesign of the control room instrumentation after the 1979 accident at Three Mile Island. A second type of capital addition project consists of major repairs that are needed to keep a plant operational, such as the replacement of the steam generator. A third category of capital additions involves discretionary expenditures needed to improve both plant performance and labor productivity.[15]

The O&M cost data were derived directly from Schedule 402 of the FERC Form 1. However, the capital additions are not directly reported and, therefore, had to be computed by calculating the year-to-year changes

[13]Utilities can recover costs in two ways. Costs that are expensed are recovered on a dollar-for-dollar basis roughly when they are incurred. Costs that are capitalized are recovered over the life of the plant by means of depreciation charges: each year, the utility earns a return on the unrecovered amount of the capitalized costs. The Uniform System of Accounts is found in the Code of Federal Regulations and is the accounting system required by FERC for ratemaking purposes.

[14]See H.l. Bowers, L.C. Fuller, and M.L. Myers, *Cost Estimating Relationships for Nuclear Power Plant Operation and Maintenance*, report submitted to the U.S. Department of Energy by Oak Ridge National Laboratory (Oak Ridge, TN, September 1987); and International Brotherhood of Electrical Workers, *Utility Department Nuclear Guide*, Vol. 87 (Washington, DC, January 1987).

[15]The EIA has undertaken a series of case studies to gain some insight into the actual composition of these capital additions costs, especially those that are required by the NRC. These case studies found that roughly 50 percent of the capital additions were regulatory induced. The other 50 percent were largely due to repairs/replacement of plant components. Only a very small fraction of the capital additions costs was undertaken to improve plant performance. See Sandy Cohen and Associates, *Analysis of the Role of Regulation in the Escalation of Nuclear Power Capital Additions Costs*, ORNL/SYB/88-SC557/1 (Oak Ridge, TN: Oak Ridge National Laboratory, July 1989).

in the "cost-of-plant" account. The data in this account are the cumulative undepreciated book value of the plant. When a major plant component is replaced, its cost, net of any salvage value, is recorded in this account.[16] Since the data in the cost-of-plant account is cumulative, the year-by-year changes should reflect the yearly *net* capital additions.

Because accounting data are being used, there will be some (hopefully random) variations in the yearly capital additions data. The cost of the repair/replacement of a plant component is recorded in the cost-of-plant account when the project is completed, and therefore, the cost of major repairs taking over one calendar year will be recorded in just one year. This causes some distortions in the timing of the costs of major capital expenditures.[17] More important, the cost of these multi-year projects will be in a mixture of dollars of various years. For example, consider a hypothetical $150 million retrofit begun in 1987 and ended in 1990. One part of that $150 million will be in 1987 dollars, another in 1988 dollars, and so on. The Gross Domestic Product (GDP) deflator for the year the costs were recorded was used to deflate the capital additions. That is, in the above example, the entire $150 million was deflated using the GDP deflator for 1990, even though some of the expenditures were in 1987, and so on. Deflating the cost with just a deflator for a single year will also introduce distortions in the yearly real capital additions data.[18]

It must also be noted that some capital additions cost data are negative. In some cases, negative capital additions costs result when the cost of replacing a plant component is less than its salvage value. However, most negative capital additions costs tend to occur in the first few years of a plant's operation, and in most cases they are due to regulatory treatment of the original capital costs. For example, a disallowance of some of a plant's original capital costs can result in a decease in the cost-of-plant account and therefore a negative capital additions for that year. Cost disallowances were identified for plants in the study, and in some cases the data were excluded.[19]

Definitional Issues

There are three data issues that affect the results of this study. These issues deal with the definition of O&M costs. The first, and perhaps the most important, definitional issue is that the reported O&M costs do not include items that are generally considered to be operating expenses. Insurance premiums for property damage, third-party damages, and replacement power in case of an accident are not included in the reported O&M costs. After the accident at Three Mile Island, insurance costs became significant. Additionally, NRC regulatory fees and some payroll taxes and fringe benefits, such as health insurance and pension costs, are reported for the entire utility and are not included in the O&M data. In total, it has been estimated that the reported O&M costs understate the actual costs by up to 30 percent.[20]

In this study, no attempt was made to correct for this understatement of total O&M costs. Since the 30-percent understatement is only an estimate and will vary substantially from utility to utility, nothing would be gained by scaling up all the costs by 30 percent. Thus, the O&M costs used in this report understate the actual costs. The understatement of total O&M costs is particularly important when the reported O&M costs are used to compare the cost of electricity generated from nuclear power plants with the cost of electricity from other generating technologies.[21]

Second, with the exceptions just noted, the O&M and capital additions costs are all nonfuel operating expenses that are expensed and capitalized, respectively, for ratemaking purposes. The Uniform System of Accounts specifies that mundane maintenance expenditures be

[16]Note that the capital additions data used here will understate the gross capital additions by the amount of salvage value of the replaced component.

[17]For example, suppose that a utility undertook a 3 year $150 million capital repair and expended $50 million dollars each year. The $150 million cost of this repair will only be reflected in the data for year 3.

[18]For a detailed discussion of the issue of the deflation of capital expenditures that are in a mixture of dollars of various years, see Energy Information Administration, *An Analysis of Nuclear Power Plant Construction Costs,* DOE/EIA-0485 (Washington, DC, 1986).

[19]An attempt was made to adjust the costs for the disallowances. When this could not be done, the data were excluded.

[20]H.I. Bowers, L.C. Fuller, and M.L. Myers, *Cost Estimating Relationships for Nuclear Power Plant Operation and Maintenance,* report submitted to the U.S. Department of Energy by Oak Ridge National Laboratory (Oak Ridge, TN, September 1987).

[21]For an example of the use of reported O&M costs for economic comparisons, see U.S. Department of Energy, *Update,* DOE/NE-0048/3 (Washington, DC, April-June 1983), p. 34. The reported O&M costs for coal are understated. Because the insurance costs in case of an accident in a coal plant are very small relative to those for nuclear power plants, the understatement of O&M costs are greater for nuclear than for coal plants.

expensed and multi-million-dollar repairs be capitalized.[22] However, there is probably a "gray area" where utilities could use their discretion in determining which costs are capitalized and which are expensed. This, in turn could result in some variations in both O&M and capital additions costs that are due to accounting factors.

Utilities recover all expensed costs on a dollar-for-dollar basis roughly when they are incurred, while the capitalized costs are recovered over a number of years by means of depreciation charges. The utility will also earn a return each year on the undepreciated value of the plant. If this return equals the "cost of capital," the utility should be indifferent to the method used to recover the costs. If, in fact, allowed returns are less than the cost of capital, there would be incentive to expense rather than capitalize costs. Many analysts believe that in the 1970s and 1980s, allowed returns were less than the cost of capital, and that the difference was increasing over time.[23] If this is true, there could be an increasing incentive to expense as many costs as possible. Thus, it is possible that some of the escalation in O&M costs could be due to accounting variations in the types of operating expenditures that are expensed.

State Public Utility Commissions (PUC) also have some control over the types of expenditures that are expensed and capitalized. Very stringent (pro-ratepayer) regulatory commissions would probably tend to capitalize as many costs as possible, because of the belief that ratepayers would prefer to postpone paying these costs.[24] Thus, these accounting variations in O&M costs could also be related to the State regulatory environment. Since this analysis attempts to relate O&M costs to State regulatory actions, this is an important point.

The question of expensing versus capitalizing arises when accounting data are used for economic analysis. Unfortunately, there is no practical way of knowing how much, if any, of the variation in O&M costs is due to differences in accounting practices. However, there could be nonrandom variations in the types of costs that are expensed.

A third definitional problem deals with the differences between the operating and maintenance components of total O&M costs. The analysis described in Chapter 3 deals in part with the relationship between economic and State regulatory factors affecting plant performance and utility maintenance practices. Based on the definitions found in the Uniform System of Accounts, utilities report operating and maintenance expenses separately. Unfortunately, the distinction between maintenance and operating costs, as defined in the Uniform System of Accounts, is not entirely clear. For example, the cost of lubricants and oil and labor expenses associated with the checking of equipment and gauges, which a recent study calls "surveillance maintenance," are considered to be operating expenses.[25] Reactor operator training is considered an operating expense, although such activities are very important for effective plant operation. Since the differentiation between operating and maintenance expenses appears to be artificial, the analysis described in Chapter 3 uses total O&M costs.

Sample Used in the Analysis

The O&M and capital additions data used in this study consisted of annual observations over the period from 1974 through 1993 for 69 commercial nuclear power plants. Several other variables used in the analysis were available only from 1975 to 1992. Thus, the sample used in the statistical analysis found in Chapter 3 and in the tabulations shown in this chapter that included economic variables (e.g., prices) used data through 1992. All the other tabulations used data through 1993. All large-scale (400 megawatts or larger) commercial light-water nuclear power plants that were in commercial operation by the end of 1993 are included. On a capacity-weighted basis, the coverage of the sample is about 95 percent of the universe.[26] The average number of time-series observations per plant is about 14. Thus, the number of observations used in the tabulations presented in this chapter was about 950.

[22]Title 10, Code of Federal Regulations, Part 101.

[23]See, for example, Peter Navarro, *The Dimming of America: The Real Cost of Electric Utility Regulatory Failure* (Boston, MA: Ballinger Publishing Company, 1985).

[24]In many respects, the issue of expensing versus capitalizing operating costs is the same as the Construction Work in Progress (CWIP) versus Allowance for Funds Used During Construction (AFUDC) controversy. Ratepayers generally prefer the AFUDC method of recovering construction costs, which is identical to the capitalization of operating costs, while utilities prefer the CWIP method, which is similar (in spirit) to the expensing of operating costs.

[25]See U.S. Nuclear Regulatory Commission, *Status of Maintenance in the U.S. Nuclear Power Industry 1985*, Vol. 1, "Findings and Conclusions," NUREG-1212 (Washington, DC, June 1986).

[26]The only two plants in operation over the 1975 to 1989 period that were excluded are Big Rock Point and Yankee Rowe, with capacities of 65 and 175 Megawatts, respectively. Additionally, Shippingport was excluded because it was owned and operated by the U.S. Department of Energy.

The O&M and capital additions data are available only at the plant (i.e., site) as opposed to the unit level. In roughly 40 percent of the cases, there is more than one unit located at the same site or plant.[27] Since some of the costs (e.g., security) are common to both units, the use of plant-level data, as opposed to unit-level data, generally presents no problems. The only time when the use of plant-level data presents major problems is when the units at a multi-unit site are of very different vintages. Fortunately, these are uncommon.

The principal way in which plant size can be increased is to add another unit at the same site. In the database used here, there were cases in which an additional unit was added to a site. However, this tended to occur in the first few years of the plant's operation. Thus, there is little variation in plant size over time.

A number of features of the data that influenced both the interpretation of the results and the analysis itself stemmed from the industry's youth and the way it evolved. First, the first power plant that this analysis treated as commercial began operation in 1967. Since the nuclear industry is rather young, average plant age as of the end of 1993 is about 15 years, and the oldest plant in the sample is about 26 years old. However, the useful life of a nuclear power plant is generally assumed to be about 30 to 40 years. Thus, care must be taken in extrapolating the results of any historical analysis of the aging issue into the future.

Second, nuclear power plants were built in two major "waves." The plants in the first wave entered construction in the late 1960s and early 1970s and became operational in the early to mid-1970s. The plants in the second wave entered construction in the early to mid-1970s and became operational in the mid-1980s. Thus, until the mid-1980s, there were 47 plants in the database. However, after 1984, the number of plants increased to 69.

Additionally, as the industry expanded, unit size also increased, because of the perception of scale economies. The size of many units that became operational in the early 1970s was about 500 to 700 megawatts, increasing to over 1,200 megawatts for units that became operational in the mid-1980s. Thus, on average the older plants are also the smaller ones. Moreover, many of the older nuclear power plants were built in regions of the country that were dependent upon expensive fossil fuels. Since the age distribution of nuclear power plants is not constant across regions, plant age will tend to be correlated with factors that vary by region.

Finally, this analysis examined the relationship between real O&M costs and the prices of O&M labor and materials. Although there were substantial regional variations in the levels of labor and materials costs, they tended to increase at roughly the same rate. As a result, there was much less regional variation in the changes in these costs over time. This point is important, because the statistical analysis focused on changes in costs over time.

Trends in Nuclear Power Plant Nonfuel Operating Costs

The remainder of this chapter describes some trends in nonfuel operating costs and in the influencing factors. These factors include plant age, NRC regulatory activity, and economic and State regulatory incentives to improve performance. The tabulations presented in this chapter must be used with great care, since they just consider one factor at a time. Such tabulations can be misleading if costs are influenced by multiple factors that are correlated with each other. Additionally, in this chapter no attempt is made to determine whether the differences in trends in costs were "real" or simply the result of random factors. These considerations are examined in detail in the statistical analysis in Chapter 3.

In total, real (inflation-adjusted) nonfuel operating costs have escalated from about $37 per kilowatt (kW) of capacity (1993 dollars) in 1974 to about $140 per kW in 1984 (Table 1).[28] The relatively high value in 1984 was due to several large capital additions. Since then, costs have fallen from that level. If the 1984 data are excluded because of these large capital additions, then nonfuel operating costs generally have escalated from 1974 to 1987.[29] From 1988 to 1993, real nonfuel operating costs have fallen slightly.

[27]For example, Calvert Cliffs 1 and Calvert Cliffs 2 are located at the same site and are therefore treated as one plant.

[28]The "real" costs presented in this chapter represent costs adjusted for the rate of inflation, as measured by the GDP implicit price deflator. This notion of "real" differs from the one used in economics, which represents changes in quantities only. (See Appendix A for a more detailed discussion of issues related to the deflation of costs.) As is discussed in Appendix A, the use of other deflators yielded results similar to those presented in this chapter. Additionally, the costs reported in this chapter are costs per kilowatt of installed capacity, as opposed to costs per kilowatthour of plant output. This issue is also discussed in Appendix A. For descriptions of the trends and tabulations of O&M costs per kilowatthour of plant output, see Energy Information Administration, *World Nuclear Outlook*, DOE/EIA-0436(94) (Washington, DC, December 1994).

[29]Note that costs fell slightly in 1978 and 1985.

Table 1. Average Annual Nonfuel Operating Costs, 1974-1993, for All Plants in Operation by 1993
(1993 Dollars per Kilowatt of Plant Capacity)

Year	Routine Operating Costs	Routine Maintenance Costs	Total Operating and Maintenance Costs	Postoperational Capital Expenditures	Total Nonfuel Operating Expenditures
1974	9.45	13.04	22.49	12.13	36.76
1975	10.79	14.32	25.11	10.66	39.71
1976	11.91	15.47	27.38	17.62	47.68
1977	13.24	16.72	29.96	26.44	58.65
1978	15.68	18.67	34.36	20.23	54.95
1979	18.25	22.58	40.83	22.77	63.46
1980	23.66	29.26	52.92	34.85	86.99
1981	21.25	33.06	54.31	45.58	101.10
1982	25.06	38.62	63.68	41.02	107.28
1983	27.69	39.74	67.43	46.21	113.98
1984	32.92	46.25	79.17	62.24	140.37
1985	27.47	46.62	74.09	35.44	113.54
1986	32.18	50.88	83.06	42.14	127.26
1987	34.33	54.93	89.27	39.73	132.26
1988	34.11	58.06	92.17	37.79	130.56
1989	35.87	57.78	93.65	34.62	129.32
1990	34.96	59.05	94.01	20.48	116.29
1991	34.63	60.62	95.24	33.63	129.53
1992	36.24	61.06	97.30	20.81	119.98
1993	35.33	61.10	96.43	28.67	125.56

Notes: Data have been deflated with the Gross Domestic Product Implicit Price Deflator. The sample consists of all plants with capacity over 400 megawatts in operation by the end of 1993. Total nonfuel operating expenditures were computed at the plant level. If either the O&M expenditures or postoperational capital expenditures were missing, it was excluded when the average total nonfuel operating cost was computed. Thus, the total nonfuel operating expenditures may not equal the sum of the components in each row.

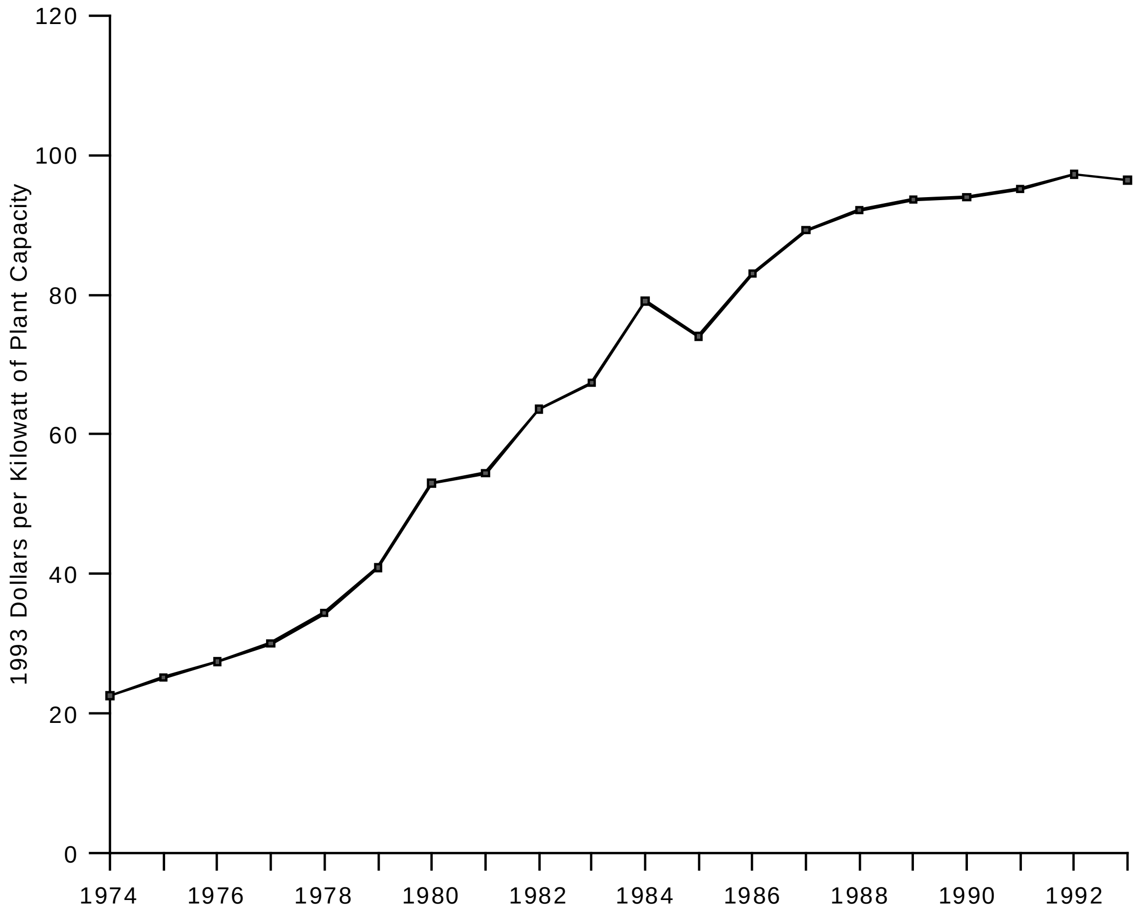
Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute.

The trends in the two components of nonfuel operating costs were slightly different. As Table 1 and Figure 1 show, real O&M costs have been escalating over the 1974-1992 period, increasing from about $22 per kW in 1974 to about $97 in 1992. Real O&M costs fell slightly in 1993. However, the bulk of the escalation occurred prior to 1988 (Figure 1). That is, over the 1974-1987 period, O&M costs were escalating at an annual rate of about 11 percent. Since then, real O&M costs have been escalating at an annual rate of less than 1 percent per year. The second component—capital additions—peaked in 1984 and has fallen to levels roughly comparable with the costs observed in the late 1970s to early 1980s (Figure 2).

In the aggregate, nuclear power plant nonfuel operating costs have been roughly constant over approximately the past 5 years. As was noted above, the second wave of power plants became operational after 1984, and as a result the sample consisted of two distinct vintages of power plants. A major issue is the impact of increased operating costs on the retirement of the older power plants (i.e., the first wave). Thus, it is important to determine whether the trends for the entire population of plants are also observed for this first wave of nuclear power plants.

This issue was examined by restricting the sample to those plants that were operational in 1983. As Table 2 and Figure 3 show, similar trends are observed for the first "wave" of power plants. Interestingly, Figure 3 suggests that the older plants had higher costs. That is, the nonfuel operating costs for the older plants are greater than the costs when both vintages of plants are included. However, the older plants are also smaller, and the statistical analysis suggests that some of the difference is due to scale economies.

Figure 1. Nuclear Power Plant Operating and Maintenance Costs, 1974-1993



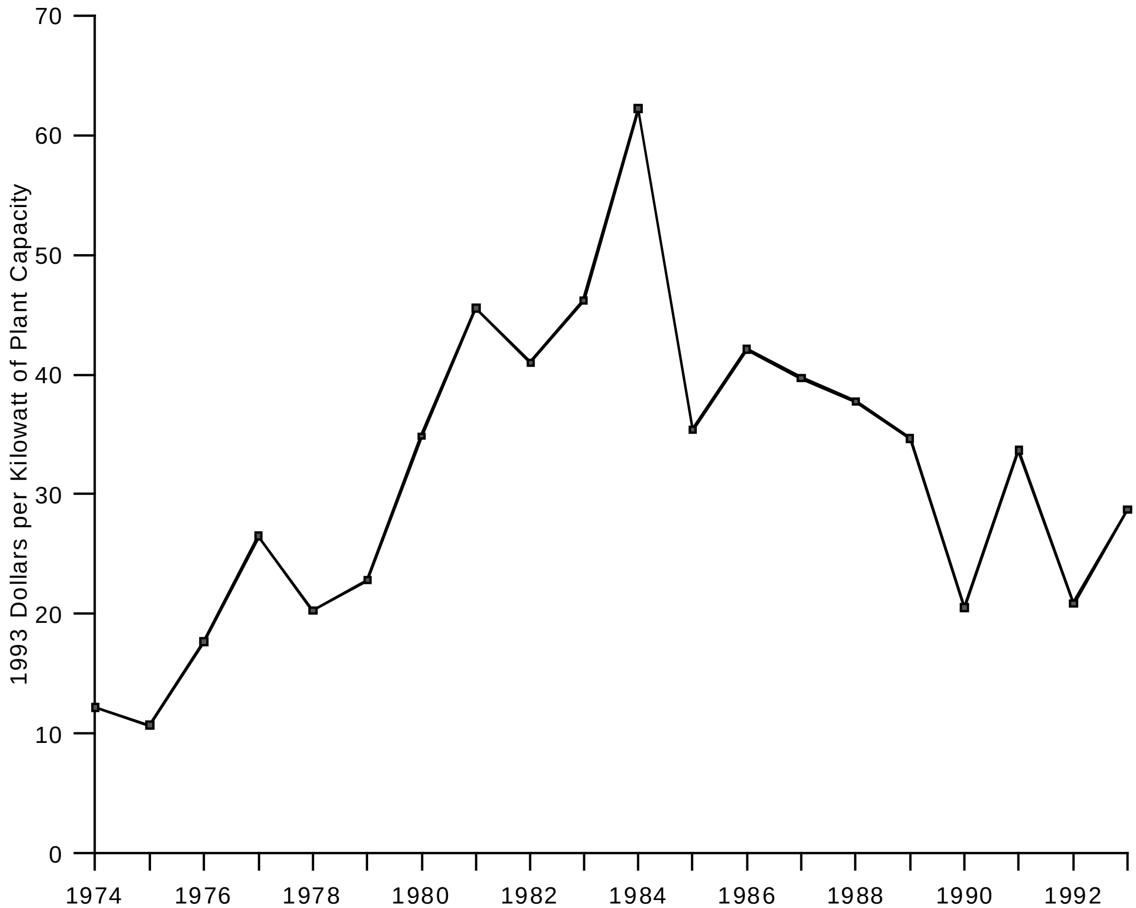
Notes: Data have been deflated with the Gross Domestic Product Implicit Price Deflator. The sample consists of all plants with capacity over 400 megawatts in operation by the end of 1993.

Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute.

There are large variations across plants in O&M costs (Table 3). The third column in Table 3 shows the average O&M costs computed over the 1990-1993 period for most of the plants in the database. The remaining columns show the ratio of each plant's 4-year moving average costs to the 4-year moving average costs for all plants.[30] For example, in 1993, the highest (lowest) cost plant's 4-year average O&M costs was 1.9 (0.6) times the industry average. A three-dimensional surface plot of real O&M costs, plant vintage (as measured by the plant's 1993 age), and plant size is shown in Figure 4. The data were obtained from Table 3. A three-dimensional surface plot is essentially a smooth "envelope" that is placed over the

[30]As was noted above, there is a substantial amount of yearly variation in the capital additions costs. Additionally, many maintenance activities can only be undertaken when the plant is out of service for refueling. Since many units are on 18 to 24 month refueling cycles, there will be some yearly variations in the O&M costs. To smooth these variations, moving averages were used. Because of missing data 3 plants were excluded from these tabulations.

Figure 2. Nuclear Power Plant Capital Additions Costs, 1974-1993



Notes: Data have been deflated with the Gross Domestic Product Implicit Price Deflator. The sample consists of all plants with capacity over 400 megawatts in operation by the end of 1993.

Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute.

data plotted in three—as opposed to two—dimensional space.[31] The older the vintage, the higher the costs (Figure 4). Additionally, holding plant vintage constant, costs fall as size increases, at least up to about 2,800 megawatts. Thus, the higher cost plants tend to be the older and smaller ones.

Comparisons of these 4-year relative moving averages show how each plant's costs were changing compared to the industry as a whole. For example, if a plant's relative costs went from 1.0 in 1979 to 0.6 in 1993, then this plant's costs were escalating at a lower rate than the industry as a whole. As Table 3 shows, with a few

[31]Because of random variations, it was necessary to smooth the data. The smoothing algorithm essentially results in a three-dimensional graphic representation of a very flexible quadratic regression, where the dependent variable is shown on the vertical axis and the two independent variables are the ones on the horizontal axes. For example, Figure 4 shows the graphic representation of a very flexible quadratic regression of O&M costs against plant size and vintage. Note that this process will result in the extrapolation of the plot outside the range of the data.

Table 2. Average Annual Nonfuel Operating Costs, 1974-1993, for All Plants in Operation by 1983
(1993 Dollars per Kilowatt of Plant Capacity)

Year	Routine Operating Costs	Routine Maintenance Costs	Total Operating and Maintenance Costs	Postoperational Capital Expenditures	Total Nonfuel Operating Expenditures
1974	9.45	13.04	22.49	12.13	36.76
1975	10.79	14.32	25.11	10.66	39.71
1976	11.91	15.47	27.38	17.62	47.68
1977	13.24	16.72	29.96	26.44	58.65
1978	15.68	18.67	34.36	20.23	54.95
1979	18.25	22.58	40.83	22.77	63.46
1980	23.66	29.26	52.92	34.85	86.99
1981	21.25	33.06	54.31	45.58	101.10
1982	25.06	38.62	63.68	41.02	107.28
1983	27.69	39.74	67.43	46.21	113.98
1984	33.10	45.73	78.83	62.24	140.37
1985	30.09	49.09	79.18	36.18	113.85
1986	34.53	51.97	86.50	47.34	133.83
1987	36.39	56.06	92.45	40.57	134.50
1988	36.56	58.98	95.55	39.55	136.34
1989	37.16	59.58	96.74	36.37	133.70
1990	36.66	63.27	99.93	20.35	119.63
1991	35.66	64.09	99.75	39.48	139.31
1992	37.27	64.43	101.70	27.20	129.59
1993	36.25	63.32	99.57	32.82	132.00

Notes: Data have been deflated with the Gross Domestic Product Implicit Price Deflator. The sample consists of all plants with capacity over 400 megawatts in operation by the end of 1983. Total nonfuel operating expenditures were computed at the plant level. If either the O&M expenditures or postoperational capital expenditures were missing, it was excluded when the average total nonfuel operating cost was computed. Thus, the total nonfuel operating expenditures may not equal the sum of the components in each row.

Sources: Federal Energy Regulatory Commission, FERC Form 1, “Annual Report of Major Electric Utilities, Licensees and Others”; Energy Information Administration, Form EIA-412, “Annual Report of Public Electric Utilities,” and predecessor survey forms; and Utility Data Institute.

exceptions, the smaller, older plants tended to always have higher costs. Just the opposite is true for the newer, larger plants.

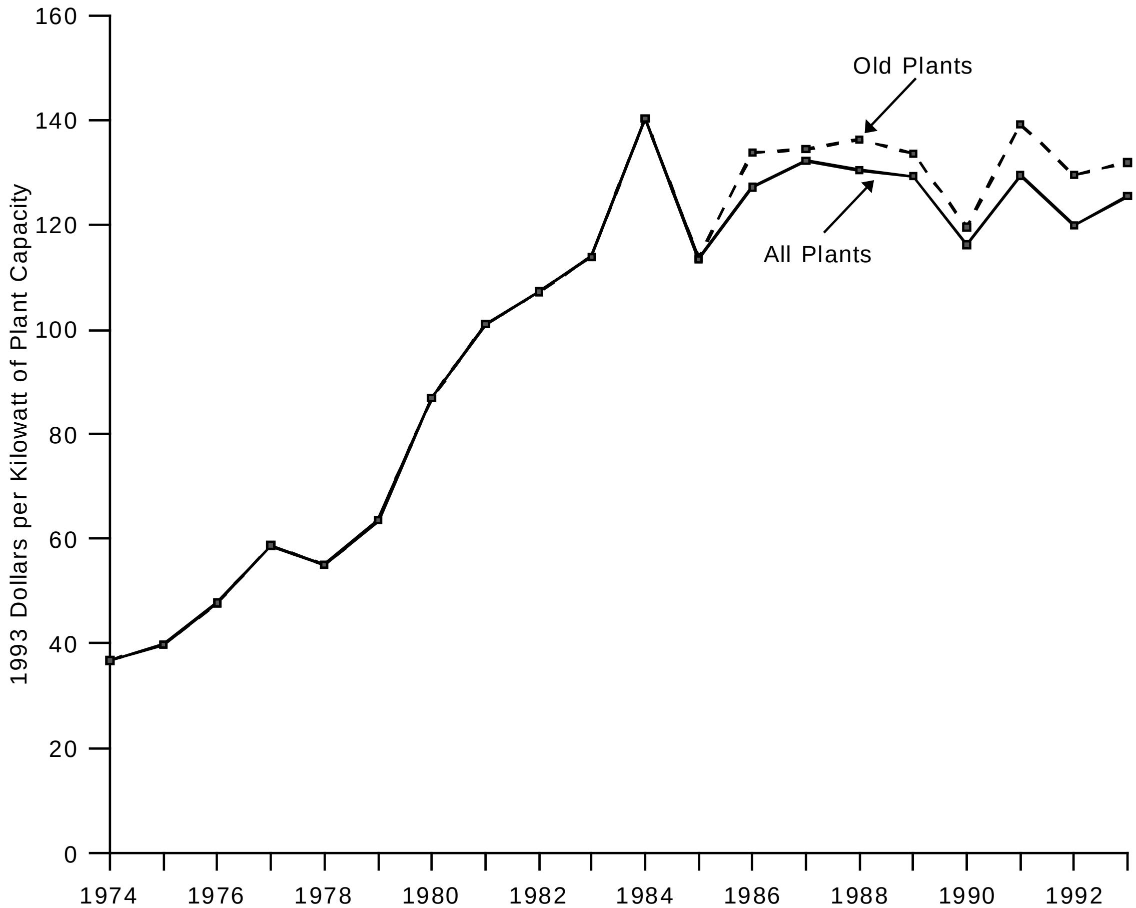
Table 4 shows similar information for total nonfuel operating costs. As was the case with O&M costs, the older, smaller (newer, larger) plants tend to have higher (lower) real O&M costs. Additionally, this relationship tended to be true over time.

Factors Influencing the Trends in Nonfuel Operating Costs

To summarize, since 1987, the annual growth rate in real O&M costs and the level of real capital additions costs fell. This update attempts to determine the reasons for the observed moderation in the growth of nuclear nonfuel operating costs. The analysis is intended to yield insights into the question of whether the trends will continue in the future. Given that substantial cost increases will influence the long-run economic viability of many plants, this issue is important.

To answer this question, the factors influencing O&M and capital additions costs must be examined. The discussion above suggests that plant vintage and plant size will influence costs at any point in time. However, these factors do not vary over time and, therefore, cannot influence the change in costs over time. In this analysis, the three most important factors influencing changes in costs over time are plant aging, NRC regulatory activity, and economic and State regulatory incentives to improve performance. The remainder of this chapter discusses these factors. Some insights can be gained by displaying the data. Thus, several important tabulations of the data are also presented.

Figure 3. Total Nonfuel Operating Costs for Old Plants and for All Plants, 1974-1993



Notes: Data have been deflated with the Gross Domestic Product Implicit Price Deflator. The sample consists of all plants with capacity over 400 megawatts in operation by the end of 1993.

Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute.

Plant Aging

Plant aging is a controversial issue. On one hand, the industry argues that there is a "break-in" period during which costs fall and performance increases, followed by a long period where costs and performance are invariant with age. Additionally, aging effects will only be observed at the very end of a plant's design life when the major plants components begin to fail. On the other hand, critics of the industry have argued that the aging process will begin early in a plant's life and will be observed over most of its life. In fact, many critics have argued that, since aging effects will be observed over the entire life of a plant, most plants will be retired before the end of their design life.[32]

[32]See James G. Hewlett, "The Financial Implications of Early Decommissioning," *The Energy Journal* (May 1991) for a review of this literature. Additionally see, G. Rothwell, "Utilization and Service: Decomposing Nuclear Power Capacity Factors," *Resources and Energy*, Vol. 12, pp. 215-229; James G. Hewlett, "The Operating Cost and Longevity of Nuclear Power Plants: Evidence from the USA," *Energy Policy* (July 1992), pp. 608-622; and U.S. Congress, Office of Technology Assessment, *Aging Nuclear Power Plants: Managing Plant Life and Decommissioning*, OTA-E-575 (Washington, DC, 1993).

Table 3. Ranking of Plants by 1990-1993 Real Operating and Maintenance Costs

Plant Name	Vintage (Years)[a]	Size (Kilowatts)	Real O&M Costs, 1990-1993[b]	O&M Costs Relative to Industry Average by Year												
				1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
Sequoyah	12.5	2,441	53.14	NA	NA	NA	0.52	0.56	0.64	0.78	0.91	0.92	0.86	0.71	0.59	0.56
Braidwood	6.0	2,450	60.03	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.63	0.66	0.63
North Anna	15.0	1,959	60.17	0.53	0.55	0.47	0.51	0.52	0.53	0.60	0.52	0.60	0.62	0.60	0.67	0.63
Byron	8.0	2,350	64.59	NA	NA	NA	NA	NA	NA	NA	0.60	0.62	0.63	0.67	0.67	0.67
Catawba	8.5	2,610	65.07	NA	NA	NA	NA	NA	NA	NA	0.58	0.61	0.65	0.67	0.66	0.68
Oconee	20.3	2,667	65.53	0.66	0.69	0.68	0.66	0.71	0.71	0.76	0.79	0.77	0.75	0.72	0.71	0.68
LaSalle	10.0	2,341	66.54	NA	NA	NA	NA	0.44	0.54	0.53	0.62	0.64	0.67	0.70	0.70	0.70
Vogtle	7.0	2,296	67.71	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.86	0.84	0.67	0.71
Prairie Island	20.5	1,186	67.95	0.65	0.61	0.60	0.55	0.58	0.60	0.61	0.66	0.59	0.62	0.63	0.67	0.71
Surry	21.5	1,695	68.47	0.59	0.54	0.57	0.58	0.59	0.67	0.65	0.73	0.74	0.73	0.76	0.71	0.72
Point Beach	23.0	1,048	68.60	0.58	0.65	0.69	0.72	0.71	0.68	0.66	0.67	0.65	0.64	0.67	0.68	0.72
South Texas	6.0	2,709	70.24	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.55	0.62	0.73
Wolf Creek	9.0	1,250	71.37	NA	NA	NA	NA	NA	NA	NA	0.66	0.73	0.71	0.72	0.68	0.75
McGuire	11.5	2,441	71.62	NA	NA	NA	0.59	0.73	0.77	0.75	0.82	0.80	0.80	0.77	0.74	0.75
Harris	7.0	951	73.21	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.78	0.80	0.77	0.76
Callaway	9.0	1,171	75.36	NA	NA	NA	NA	NA	NA	NA	0.94	0.94	0.88	0.78	0.79	0.79
Comanche Peak	4.0	2,430	75.87	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.79
Zion	20.5	2,196	77.34	0.57	0.57	0.54	0.51	0.51	0.49	0.51	0.59	0.61	0.68	0.74	0.77	0.81
Maine Yankee	22.0	864	79.66	0.62	0.64	0.63	0.65	0.67	0.57	0.63	0.65	0.59	0.73	0.68	0.73	0.83
Susquehanna	10.0	2,304	79.89	NA	NA	NA	NA	NA	0.90	0.91	0.87	0.85	0.84	0.86	0.83	0.83
Millstone 3	8.0	1,253	80.26	NA	NA	NA	NA	NA	NA	NA	NA	0.65	0.72	0.72	0.77	0.84
Seabrook	4.0	1,197	81.41	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.85
Donald C. Cook	17.5	2,285	81.84	0.48	0.50	0.51	0.54	0.62	0.66	0.70	0.71	0.68	0.73	0.73	0.82	0.85
Grand Gulf	9.0	1,373	82.35	NA	NA	NA	NA	NA	NA	NA	0.96	0.97	0.91	0.83	0.86	0.86
WNP	9.0	1,200	86.19	NA	NA	NA	NA	NA	NA	NA	0.76	0.82	0.83	0.86	0.88	0.90
Limerick	8.0	2,276	86.42	NA	NA	NA	NA	NA	NA	NA	NA	1.22	1.28	1.10	0.97	0.90
Cooper	20.0	836	86.81	0.68	0.68	0.73	0.67	0.70	0.76	0.77	0.85	0.86	0.91	0.90	0.88	0.91
Hope Creek	7.0	1,170	86.90	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.89	0.91	0.92	0.91
V.C. Summer	10.0	954	87.15	NA	NA	NA	NA	NA	NA	1.09	1.02	0.96	0.94	0.93	0.93	0.91
Waterford 3	9.0	1,153	87.18	NA	NA	NA	NA	NA	NA	NA	0.88	1.07	1.00	0.98	0.95	0.91
Joseph M. Farley	15.0	1,777	90.22	0.89	0.84	0.75	0.71	0.78	0.84	0.89	0.92	0.91	0.90	0.89	0.93	0.94
Palo Verde	7.3	4,209	91.42	NA	NA	NA	NA	NA	NA	NA	NA	0.81	0.89	0.90	0.92	0.95
St. Lucie	14.5	1,700	91.65	0.80	0.69	0.61	0.62	0.61	0.63	0.70	0.69	0.66	0.76	0.80	0.87	0.96
Edwin I. Hatch	17.0	1,700	94.38	1.04	1.02	1.03	1.20	1.31	1.51	1.43	1.27	1.15	1.00	1.00	1.02	0.99
Arkansas Nuclear 1	17.0	1,845	94.81	0.78	0.75	0.71	0.75	0.72	0.75	0.80	0.87	0.91	0.97	1.00	0.99	0.99
Salem	15.0	2,340	94.91	1.40	1.49	1.45	1.42	1.46	1.35	1.19	1.05	0.93	0.87	0.87	0.90	0.99
Dresden	24.8	1,665	96.01	0.91	0.79	0.66	0.65	0.65	0.69	0.73	0.79	0.83	0.86	0.91	0.94	1.00
Calvert Cliffs	18.0	1,829	96.26	0.82	0.80	0.73	0.68	0.67	0.62	0.62	0.62	0.65	0.76	0.88	0.96	1.01
Beaver Valley	12.5	1,847	96.43	1.22	1.30	1.41	1.42	1.37	1.25	0.97	0.81	0.79	0.76	0.90	0.96	1.01
Palisades	23.0	812	97.80	1.24	1.22	1.24	1.29	1.23	1.26	1.17	1.20	1.17	1.11	1.11	1.04	1.02
San Onofre	13.0	2,710	98.71	1.75	1.76	1.73	1.66	1.69	1.51	1.42	1.21	1.06	1.03	1.05	1.08	1.03
Enrico Fermi	6.0	1,154	100.25	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.31	1.16	1.05
Diablo Canyon	8.5	2,301	100.49	NA	NA	NA	NA	NA	NA	NA	0.90	1.00	1.01	1.09	1.06	1.05
Quad Cities	21.0	1,657	100.80	0.77	0.71	0.64	0.65	0.66	0.65	0.66	0.66	0.70	0.78	0.88	0.99	1.05
Monticello	23.0	569	101.86	1.01	1.09	1.06	1.09	1.08	1.01	1.05	0.97	1.01	0.99	1.05	1.06	1.06
Duane Arnold	19.0	597	103.11	1.00	1.01	1.23	1.20	1.35	1.27	1.18	1.22	1.02	1.12	1.01	1.00	1.08
Peach Bottom	20.0	2,304	104.85	0.88	0.84	0.88	0.85	0.91	0.93	0.97	1.24	1.28	1.31	1.33	1.14	1.10
H.B. Robinson	23.0	769	106.70	0.93	1.01	1.04	1.19	1.21	1.17	1.13	1.03	0.99	1.01	1.02	1.04	1.11
Clinton	7.0	985	109.18	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.10	1.12	1.14	1.14
Davis-Besse	16.0	962	110.76	1.21	1.33	1.31	1.19	1.26	1.36	1.54	1.84	1.84	1.76	1.58	1.31	1.16
Kewaunee	20.0	535	111.77	1.01	0.97	0.96	0.95	0.96	0.95	0.97	1.05	1.08	1.13	1.20	1.20	1.17
Perry	7.0	1,250	112.97	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.19	1.33	1.26	1.18
Indian Point 3	18.0	1,013	112.98	1.49	1.64	1.53	1.34	1.28	1.04	0.98	0.89	0.85	0.92	1.15	1.18	1.18
Crystal River 3	17.0	890	119.59	1.36	1.40	1.54	1.58	1.53	1.49	1.36	1.24	1.25	1.25	1.26	1.29	1.25
Nine Mile Point	12.9	1,854	121.91	0.80	0.83	0.83	0.87	0.70	0.62	0.47	0.51	0.75	1.00	1.22	1.29	1.27
Turkey Point	21.5	1,520	122.52	0.65	0.59	0.60	0.61	0.68	0.86	0.97	1.13	1.24	1.32	1.42	1.36	1.28
Vermont Yankee	22.0	563	125.53	1.28	1.32	1.47	1.46	1.47	1.47	1.35	1.25	1.19	1.21	1.15	1.24	1.31
Brunswick	18.0	1,416	126.56	1.06	1.21	1.30	1.33	1.47	1.42	1.37	1.34	1.20	1.12	1.11	1.22	1.32
Robert E. Ginna	24.0	517	132.04	1.19	1.24	1.22	1.18	1.14	1.09	1.07	1.08	1.19	1.27	1.37	1.42	1.38
Indian Point	23.0	873	135.69	1.65	1.65	1.51	1.69	1.54	1.48	1.61	1.40	1.56	1.55	1.42	1.49	1.42
River Bend	8.0	1,036	136.79	NA	NA	NA	NA	NA	NA	NA	NA	1.37	1.43	1.40	1.47	1.43
Connecticut Yankee	26.0	600	143.22	1.58	1.64	1.69	1.65	1.54	1.72	1.81	1.72	1.81	1.64	1.53	1.52	1.50
James A. Fitzpatrick	19.0	883	143.99	1.25	1.12	1.06	1.02	1.02	1.04	1.07	1.12	1.10	1.20	1.24	1.49	1.50
Pilgrim	22.0	678	144.78	1.33	1.38	1.42	1.58	1.60	1.64	1.86	1.94	2.01	1.96	1.75	1.58	1.51
Ft. Calhoun	21.0	502	153.56	0.86	0.85	0.91	0.89	0.97	1.02	1.06	1.31	1.70	1.87	1.96	1.87	1.60
Oyster Creek	25.0	650	178.07	1.93	2.15	2.52	2.68	2.88	3.09	2.97	2.71	2.40	2.02	1.89	1.87	1.86

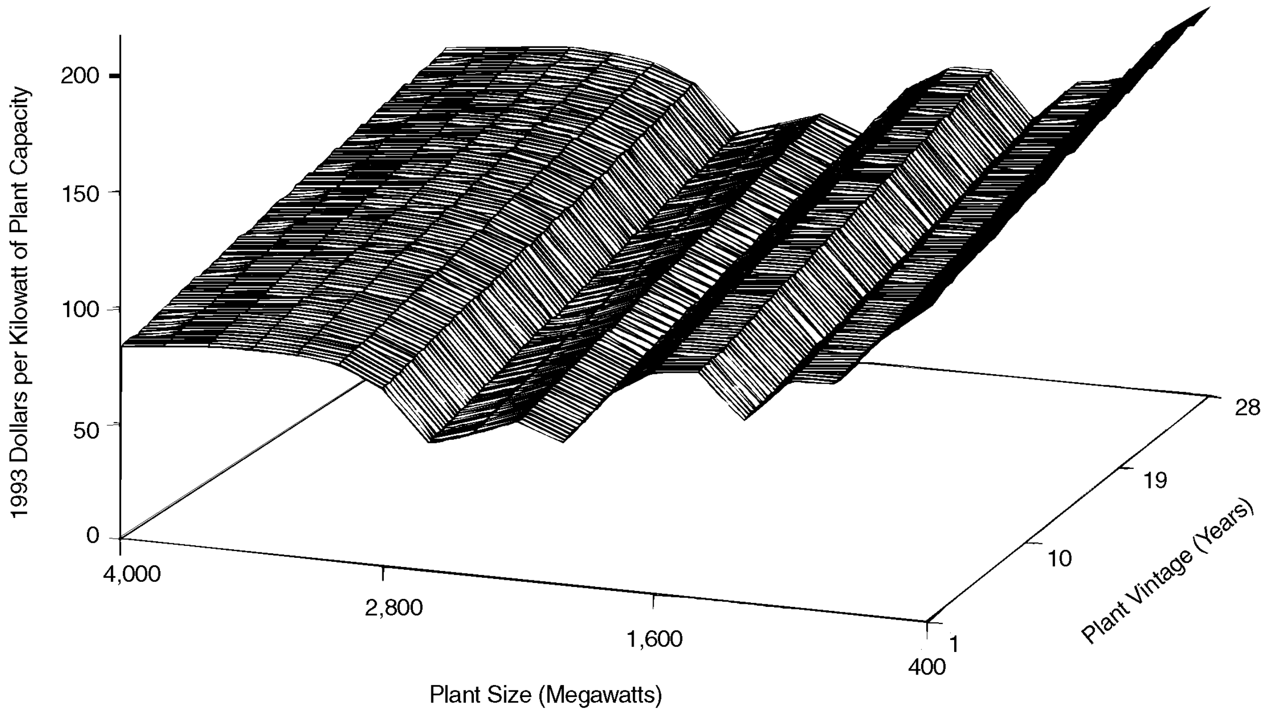
[a]Plant age as of 1993 was used to measure vintage.

[b]1993 dollars per kilowatt of capacity.

Notes: The data in the column labeled "Real O&M Costs, 1990-1993" are averages over that time period. The data in the other columns are 4-year moving averages for each plant relative to industry-wide 4-year moving averages. An entry of "NA" indicates not applicable because the plant was not operational in that year or because data were not available. Data have been deflated with the Gross Domestic Product Implicit Price Deflator. The sample consists of all plants with capacity over 400 megawatts in operation by the end of 1993.

Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute.

Figure 4. Surface Plot of Real Operating and Maintenance Costs, Plant Vintage, and Plant Size



Notes: Data have been deflated with the Gross Domestic Product Implicit Price Deflator. The sample consists of all plants with capacity over 400 megawatts in operation by the end of 1993. Plant vintage is measured by the 1993 age of the plant. The mathematical algorithm used to smooth the data and generate the surface plot will extrapolate the plot outside the range of the data.

Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute.

Most utilities own only one nuclear power plant (as opposed to one unit); therefore, plant age and utility experience will be highly correlated. This is because each year a plant will become one year older and the owner's experience will increase by one year. Plant aging could cause costs to increase while increased utility experience could cause costs to fall. Since these two factors are so highly correlated, it was impossible to derive separate estimates of both effects. Thus, the observed relationship between plant age and costs will depend upon the relative strength of these two effects.

Tabulations of real O&M and capital additions costs by age, date of the observations, and reactor type are shown in Tables 5 and 6, respectively. Real O&M and capital additions costs by age and reactor types are plotted in Figures 5 and 6. Surface plots of real O&M and capital additions costs against plant age and time are shown in Figures 7 and 8, respectively. Figure 7, along with the data in Table 5 and Figure 5, suggests that real O&M costs increase with age. However, the statistical analysis could not find any measurable correlation between plant age and real O&M costs. (This apparent correlation between age and O&M costs is, therefore, due to other factors that are correlated with age.)

These tabulations and plots also suggest that the relationship between capital additions costs, age, and time varies over time and the life of the plant. When

Table 4. Ranking of Plants by 1990-1993 Total Nonfuel Operating Costs

Plant Name	Vintage (Years)[a]	Size (Kilowatts)	Total Costs, 1990-1993[b]	O&M Costs Relative to Industry Average by Year												
				1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
Catawba	8.5	2,610	65.61	NA	NA	NA	NA	NA	NA	NA	0.6	0.6	0.6	0.6	0.6	0.5
WNP	9.0	1,200	71.98	NA	NA	NA	NA	NA	NA	NA	0.8	0.9	0.8	0.7	0.6	0.6
Braidwood	6.0	2,450	73.46	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.6	0.6	0.6
Oconee	20.3	2,667	74.26	0.6	0.6	0.6	0.6	0.6	0.6	0.8	0.9	0.9	0.9	0.6	0.6	0.6
Callaway	9.0	1,171	74.60	NA	NA	NA	NA	NA	NA	NA	0.7	0.7	0.7	0.6	0.6	0.6
Wolf Creek	9.0	1,250	75.34	NA	NA	NA	NA	NA	NA	NA	0.6	0.6	0.7	0.8	0.6	0.6
Byron	8.0	2,350	78.41	NA	NA	NA	NA	NA	NA	NA	0.5	0.4	0.5	0.4	0.6	0.6
McGuire	11.5	2,441	78.54	NA	NA	NA	0.6	0.5	0.5	0.6	0.6	0.6	0.7	0.6	0.6	0.6
Grand Gulf	9.0	1,373	82.29	NA	NA	NA	NA	NA	NA	NA	0.9	1.0	0.9	0.8	0.8	0.7
LaSalle	10.0	2,341	87.05	NA	NA	NA	NA	0.5	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.7
North Anna	15.0	1,959	88.34	0.8	0.8	0.8	0.7	0.7	0.5	0.6	0.5	0.6	0.7	0.6	0.7	0.7
Susquehanna	10.0	2,304	88.61	NA	NA	NA	NA	NA	0.8	0.9	0.8	0.9	0.9	0.7	0.7	0.7
Donald C. Cook	17.5	2,285	91.36	0.8	0.8	0.7	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.7
Zion	20.5	2,196	93.23	0.7	0.6	0.6	0.5	0.5	0.4	0.5	0.5	0.5	0.6	0.6	0.7	0.7
Millstone 3	8.0	1,253	93.49	NA	NA	NA	NA	NA	NA	NA	NA	1.0	1.0	0.7	0.7	0.7
Vogtle	7.0	2,296	93.87	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.9	0.9	0.7	0.7
Maine Yankee	22.0	864	94.47	0.7	0.7	0.7	0.7	0.7	0.5	0.6	0.6	0.5	0.7	0.6	0.6	0.8
V.C. Summer	10.0	954	94.99	NA	NA	NA	NA	NA	NA	0.9	0.8	0.7	0.8	0.8	0.7	0.8
South Texas	6.0	2,709	96.41	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.6	0.7	0.8
Comanche Peak	4.0	2,430	98.45	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.8
Sequoyah	12.5	2,441	99.26	NA	NA	NA	0.7	0.7	0.6	0.8	0.9	1.0	0.9	0.8	0.7	0.8
Joseph M. Farley	15.0	1,777	101.24	1.4	1.4	1.1	1.0	0.8	0.8	0.8	0.8	0.8	0.7	0.8	0.8	0.8
St. Lucie	14.5	1,700	101.35	0.9	0.8	0.7	0.8	0.7	0.9	1.1	0.9	0.8	0.7	0.6	0.7	0.8
Edwin I. Hatch	17.0	1,700	103.04	1.3	1.2	1.4	1.5	1.5	1.7	1.6	1.4	1.3	0.9	0.9	0.9	0.8
Surry	21.5	1,695	103.75	2.0	1.8	1.7	1.1	0.6	0.7	0.7	0.8	0.8	0.8	0.9	0.8	0.8
Prairie Island	20.5	1,186	106.28	0.8	0.8	0.7	0.7	0.7	0.7	0.8	0.7	0.6	0.6	0.5	0.8	0.8
Waterford 3	9.0	1,153	107.56	NA	NA	NA	NA	NA	NA	NA	1.0	1.6	1.6	1.5	1.4	0.9
Seabrook	4.0	1,197	107.57	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.9
Harris	7.0	951	109.45	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.9	1.1	1.0	0.9
Point Beach	23.0	1,048	112.05	0.4	0.6	0.7	0.7	0.7	0.6	0.6	0.6	0.5	0.5	0.6	0.9	0.9
Cooper	20.0	836	112.97	1.1	1.1	1.1	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Monticello	23.0	569	115.18	1.2	1.4	1.6	2.3	2.1	1.9	1.7	1.0	1.0	1.0	1.0	1.0	0.9
Arkansas Nuclear 1	17.0	1,845	115.68	1.1	1.0	0.8	0.8	0.8	0.8	0.9	0.9	0.9	1.0	0.9	0.9	0.9
Dresden	24.8	1,665	115.71	1.0	0.8	0.6	0.8	0.8	0.8	1.0	0.8	0.9	0.8	0.7	0.8	0.9
Palo Verde	7.3	4,209	117.58	NA	NA	NA	NA	NA	NA	NA	NA	0.9	0.9	0.9	0.9	0.9
Hope Creek	7.0	1,170	119.63	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.1	1.1	1.0	1.0
Beaver Valley	12.5	1,847	122.59	1.9	2.3	2.4	2.2	2.0	1.5	1.3	1.0	0.9	0.8	0.9	0.9	1.0
Kewaunee	20.0	535	122.88	1.2	1.1	1.1	1.1	0.9	0.8	0.8	0.9	0.9	0.9	1.0	1.0	1.0
Limerick	8.0	2,276	123.99	NA	NA	NA	NA	NA	NA	NA	NA	1.1	1.4	1.1	1.0	1.0
Calvert Cliffs	18.0	1,829	124.38	0.9	0.9	0.9	0.8	0.8	0.6	0.6	0.6	0.6	0.6	0.8	0.9	1.0
San Onofre	13.0	2,710	124.87	3.0	3.0	2.7	2.4	1.9	1.4	1.4	1.2	1.1	1.0	1.0	1.0	1.0
Clinton	7.0	985	127.95	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.7	0.7	0.6	1.0
Indian Point 3	18.0	1,013	129.80	1.8	1.9	1.7	1.4	1.4	1.1	1.2	1.1	1.1	1.0	1.2	1.1	1.0
Peach Bottom	20.0	2,304	131.24	1.1	1.1	1.1	1.0	1.1	0.9	1.0	1.2	1.1	1.3	1.3	1.1	1.0
Quad Cities	21.0	1,657	131.27	0.8	0.8	0.7	0.9	0.8	0.7	0.8	0.6	0.6	0.7	0.8	0.9	1.0
Enrico Fermi	6.0	1,154	131.28	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.3	1.2	1.0
Salem	15.0	2,340	132.38	2.0	2.0	1.5	1.5	1.3	1.2	1.0	1.0	0.9	0.9	0.9	0.9	1.1
Davis-Besse	16.0	962	132.39	3.0	2.5	1.9	1.6	1.4	1.4	1.3	1.9	2.2	1.9	2.0	1.5	1.1
Vermont Yankee	22.0	563	132.82	1.5	1.4	1.6	1.4	1.3	1.5	1.3	1.2	1.2	1.0	0.9	1.0	1.1
H.B. Robinson	23.0	769	135.98	1.0	1.1	1.0	1.7	1.5	1.5	1.9	1.1	1.2	1.2	0.9	1.2	1.1
Perry	7.0	1,250	139.13	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.2	1.2	1.2	1.1
River Bend	8.0	1,036	143.06	NA	NA	NA	NA	NA	NA	NA	NA	1.1	1.1	1.1	1.2	1.1
Diablo Canyon	8.5	2,301	144.77	NA	NA	NA	NA	NA	NA	NA	0.9	0.9	1.0	1.0	1.1	1.2
Duane Arnold	19.0	597	145.98	1.6	1.7	1.7	1.5	1.6	1.4	1.4	1.4	1.2	1.3	1.1	1.1	1.2
Nine Mile Point	12.9	1,854	148.07	1.6	1.6	1.9	2.2	1.6	1.6	1.1	0.8	0.9	0.9	1.1	1.1	1.2
Crystal River 3	17.0	890	150.75	1.3	1.2	1.3	1.3	1.4	1.4	1.3	1.2	1.1	1.1	1.1	1.2	1.2
Brunswick	18.0	1,416	150.94	1.3	1.3	1.4	1.5	1.6	1.6	1.5	1.4	1.3	1.3	1.1	1.1	1.2
Connecticut Yankee	26.0	600	155.78	1.8	1.8	1.8	1.6	1.3	1.4	1.7	1.6	1.8	1.6	1.3	1.4	1.2
Palisades	23.0	812	161.86	1.7	1.6	2.1	1.9	1.5	1.3	1.0	1.0	1.0	1.0	1.2	1.2	1.3
James A. Fitzpatrick	19.0	883	165.73	1.6	1.2	1.1	1.2	1.0	1.0	1.1	1.0	1.0	1.1	1.1	1.3	1.3
Indian Point	23.0	873	168.24	1.8	1.9	1.7	1.8	1.3	1.2	1.3	1.2	1.5	1.4	1.3	1.4	1.3
Turkey Point	21.5	1,520	174.82	0.7	1.0	1.2	1.2	1.2	1.1	1.2	1.2	1.4	1.4	1.6	1.6	1.4
Robert E. Ginna	24.0	517	190.82	1.7	1.7	1.8	1.7	1.4	1.4	1.3	1.2	1.3	1.3	1.4	1.6	1.5
Pilgrim	22.0	678	200.97	2.3	2.6	2.6	2.9	2.7	2.2	2.3	2.5	2.6	2.5	2.4	1.6	1.6
Ft. Calhoun	21.0	502	203.17	1.0	1.1	1.1	1.0	1.0	0.9	0.9	1.1	1.5	1.8	1.9	1.9	1.6
Oyster Creek	25.0	650	262.97	3.3	2.9	3.5	3.4	3.4	3.5	3.3	2.9	2.7	2.1	2.0	2.0	2.1

[a]Plant age as of 1993 was used to measure vintage.

[b]1993 dollars per kilowatt of capacity.

Notes: The data in the column labeled "Total Costs, 1990-1993" are averages over that time period. The data in the other columns are 4-year moving averages for each plant relative to industry-wide 4-year moving averages. An entry of "NA" indicates not applicable because the plant was not operational in that year or because data were not available. Data have been deflated with the Gross Domestic Product Implicit Price Deflator. The sample consists of all plants with capacity over 400 megawatts in operation by the end of 1993.

Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute.

Table 5. Operating and Maintenance Costs by Year, Age of Plant, and Reactor Type, 1974-1993
(1993 Dollars per Unit of Plant Capacity)

Age of Plant	1974-1976	1977-1980	1981-1984	1985-1989	1990-1993
	Pressurized-Water Reactors				
0-3 years	14.50	24.59	45.79	60.91	73.10
3-6 years	24.15	39.86	54.52	74.74	73.00
6-8 years	30.55	31.66	64.70	73.70	78.02
8-9 years	45.19	39.37	56.58	80.56	78.75
10-12 years	NA	46.76	51.97	83.59	76.99
12-14 years	NA	82.50	68.48	77.96	85.48
14-17 years	NA	NA	97.96	84.18	100.81
17-20 years	NA	NA	136.22	103.64	95.79
20-23 years	NA	NA	NA	153.94	96.82
>23 years	NA	NA	NA	NA	126.68
All plants	22.87	37.85	62.02	80.94	89.54
	Boiling-Water Reactors				
0-3 years	19.38	22.48	34.97	90.05	NA
3-6 years	31.13	37.89	57.39	91.75	103.51
6-8 years	40.76	41.45	64.17	69.83	104.27
8-9 years	32.31	46.43	65.96	120.12	103.56
10-12 years	NA	49.53	64.85	98.58	90.48
12-14 years	NA	71.75	83.81	80.67	127.90
14-17 years	NA	NA	104.37	98.29	88.34
17-20 years	NA	NA	NA	117.05	105.58
20-23 years	NA	NA	NA	145.83	116.81
>23 years	NA	NA	NA	NA	142.31
All plants	29.15	42.87	74.59	97.72	107.13
	All Plants				
0-3 years	16.37	24.38	44.71	71.61	73.10
3-6 years	26.94	39.23	54.67	80.41	84.81
6-8 years	35.38	35.20	64.57	73.15	88.12
8-9 years	40.90	42.65	59.95	85.21	87.02
10-12 years	NA	48.07	56.89	87.22	81.48
12-14 years	NA	78.91	75.60	78.95	89.02
14-17 years	NA	NA	100.84	89.87	97.51
17-20 years	NA	NA	136.22	109.49	100.16
20-23 years	NA	NA	NA	150.46	104.26
>23 years	NA	NA	NA	NA	132.54
All plants	25.40	39.57	66.10	86.68	95.69

NA = not available.

Notes: Data have been deflated with the Gross Domestic Product Implicit Price Deflator. The sample consists of all plants with capacity over 400 megawatts in operation by the end of 1993.

Sources: Federal Energy Regulatory Commission, FERC Form 1, “Annual Report of Major Electric Utilities, Licensees and Others”; Energy Information Administration, Form EIA-412, “Annual Report of Public Electric Utilities,” and predecessor survey forms; and Utility Data Institute.

Table 6. Capital Additions Costs by Year, Age of Plant, and Reactor Type, 1974-1993
(1993 Dollars per Unit of Plant Capacity)

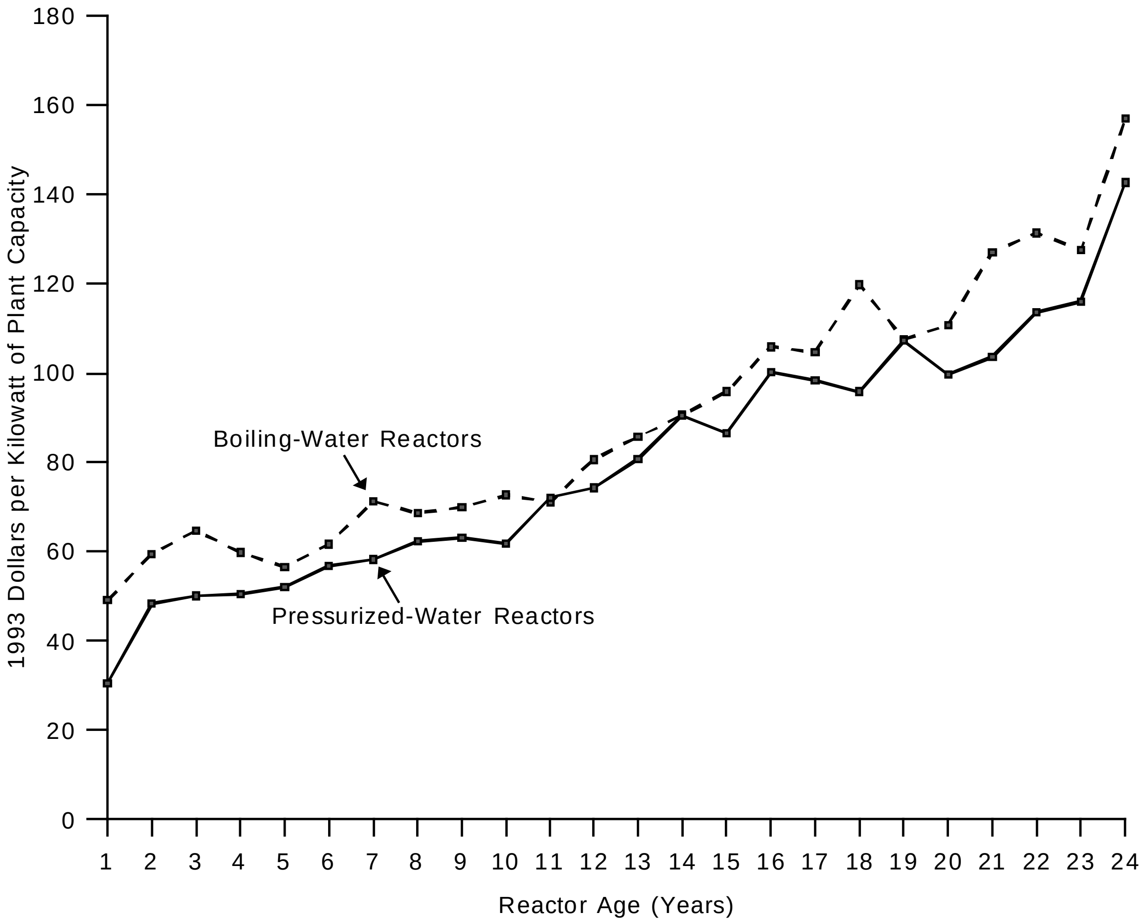
Age of Plant	1974-1976	1977-1980	1981-1984	1985-1989	1990-1993
			Pressurized-Water Reactors		
0-3 years	8.18	40.84	18.28	28.43	25.17
3-6 years	13.74	20.15	38.75	27.87	33.95
6-8 years	12.49	12.44	30.84	30.93	12.31
8-9 years	20.60	24.50	33.45	36.41	6.88
10-12 years	NA	55.03	40.56	40.30	19.88
12-14 years	NA	41.30	40.51	34.80	25.69
14-17 years	NA	NA	80.93	31.05	23.69
17-20 years	NA	NA	19.42	37.56	33.04
20-23 years	NA	NA	NA	63.62	33.02
>23 years	NA	NA	NA	NA	25.63
All plants	12.60	25.38	39.79	34.13	24.31
			Boiling-Water Reactors		
0-3 years	27.12	-12.74	0.00	33.09	NA
3-6 years	9.39	20.56	20.56	21.69	25.14
6-8 years	16.62	18.53	30.90	17.11	23.39
8-9 years	56.07	31.10	41.21	32.87	-3.42
10-12 years	NA	38.16	43.94	54.64	24.08
12-14 years	NA	78.54	95.38	38.00	NA
14-17 years	NA	NA	141.55	42.93	35.48
17-20 years	NA	NA	NA	80.56	37.22
20-23 years	NA	NA	NA	62.40	26.46
>23 years	NA	NA	NA	NA	64.52
All plants	17.73	27.72	69.05	46.20	29.01
			All Plants		
0-3 years	15.07	36.37	14.63	30.25	25.17
3-6 years	12.06	20.26	37.74	25.86	29.06
6-8 years	14.45	14.28	30.85	28.81	16.81
8-9 years	32.42	27.56	35.97	35.97	3.58
10-12 years	NA	47.04	41.72	43.78	20.93
12-14 years	NA	53.72	65.99	35.86	25.69
14-17 years	NA	NA	108.21	35.48	26.81
17-20 years	NA	NA	19.42	56.30	34.75
20-23 years	NA	NA	NA	63.10	30.67
>23 years	NA	NA	NA	NA	40.21
All plants	14.63	26.13	49.08	38.12	25.97

NA = not available.

Notes: Data have been deflated with the Gross Domestic Product Implicit Price Deflator. The sample consists of all plants with capacity over 400 megawatts in operation by the end of 1993.

Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute.

Figure 5. Operating and Maintenance Costs, 1974-1993, by Reactor Age and Type



Notes: Data have been deflated with the Gross Domestic Product Implicit Price Deflator. The sample consists of all plants with capacity over 400 megawatts in operation by the end of 1993.

Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute.

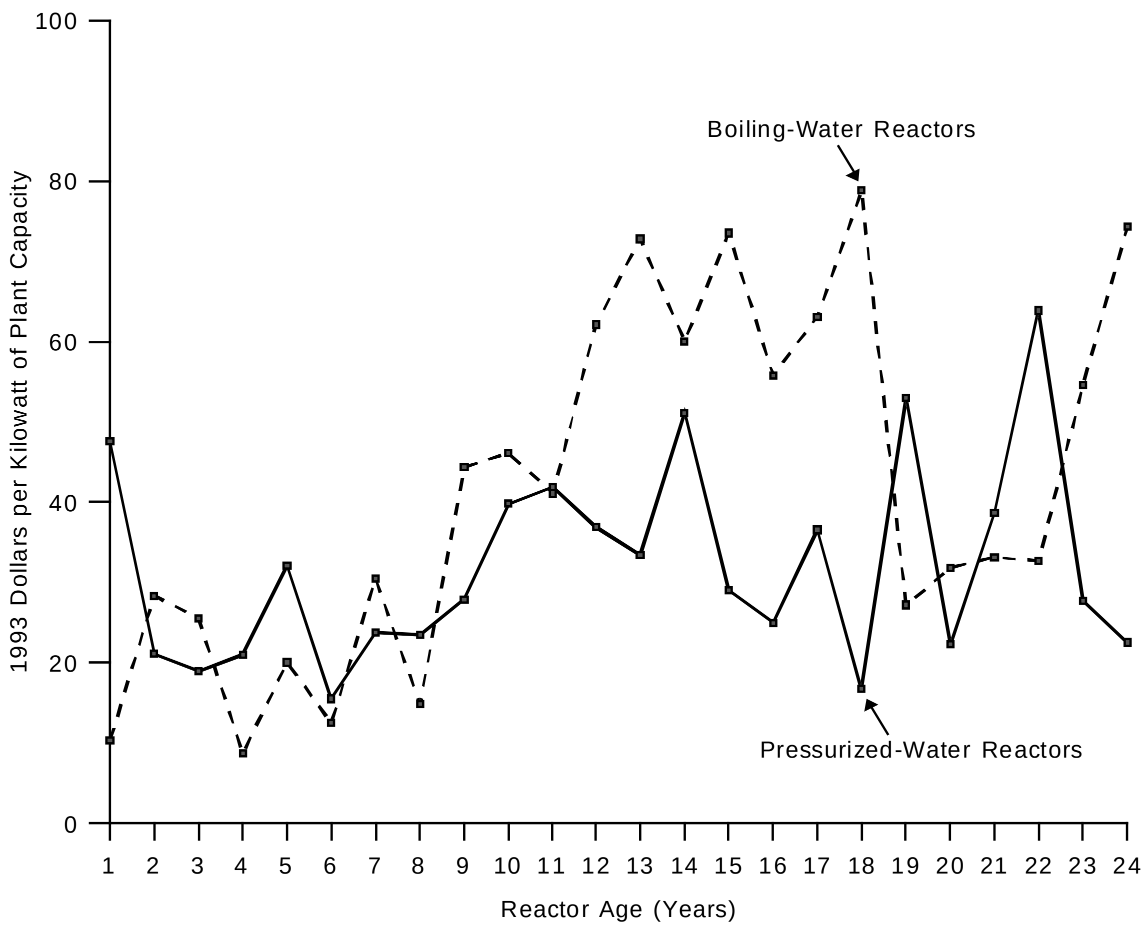
age was held constant, capital additions costs increased until the mid-1980s and then fell (Figure 8).[33] Additionally, at any point in time, it would appear that capital additions costs fell until the plant was about 10 years old and then increased (Figure 8). Interestingly, the detailed statistical analysis also found a varied relationship between capital additions costs, age, and time.

NRC Regulatory Requirements

One of the key factors influencing operating costs is changes over time in regulatory activity. There are two aspects of NRC regulatory actions. The first is the number and kind of NRC regulatory requirements. Unfortunately, there is no direct measure of the effects

[33]Note that the smoothing algorithm tended to overstate the decreases in capital additions costs over the first 10 years of the plant's life.

Figure 6. Real Capital Additions Costs, 1974-1993, by Reactor Age and Type



Notes: Data have been deflated with the Gross Domestic Product Implicit Price Deflator. The sample consists of all plants with capacity over 400 megawatts in operation by the end of 1993.

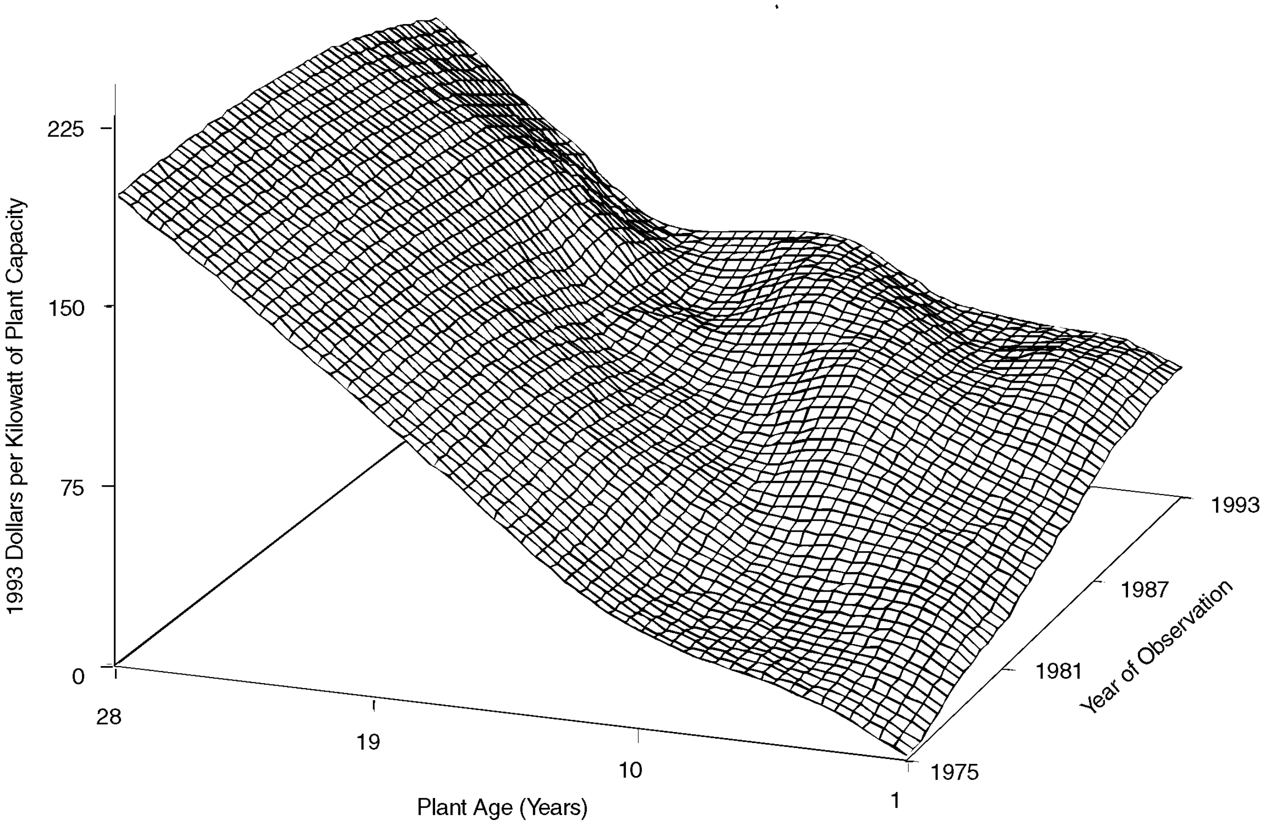
Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute.

of these regulatory actions, and consequently another measure must be used to approximate the effects of increased NRC regulatory actions. This analysis used two measures to approximate the regulatory effects. The first was the cumulative number of NRC regulatory actions. These regulatory actions include formal changes in the Code of Federal Regulations, regulatory bulletins, regulatory guides, and all generic letters.[34] As Figure 9 shows, this measure of regulatory activity was increasing at roughly the same absolute rate over the entire period. For the second measure of NRC regulatory activity, time itself was used.[35]

[34]These points are discussed in more detail in Chapter 3.

[35]In the original 1988 study and the 1991 update, time itself was the only measure that was used. That is, the statistical analysis controlled for all measurable factors, and the cost escalation that remained was attributed to regulation. Because of the problems with using a time trend, the present study will also use the cumulative number of NRC regulatory actions to approximate the effects of NRC regulatory actions. See Energy Information Administration, *An Analysis of Nuclear Power Plant Operating Costs*, DOE/EIA-0511 (Washington, DC, 1988), and *An Analysis of Nuclear Power Plant Operating Costs: A 1991 Update*, DOE/EIA-0547, (Washington, DC, 1991).

Figure 7. Surface Plot of Real Operating and Maintenance Costs, Plant Age, and Year of Observation



Notes: Data have been deflated with the Gross Domestic Product Implicit Price Deflator. The sample consists of all plants with capacity over 400 megawatts in operation by the end of 1993. The mathematical algorithm used to smooth the data and generate the surface plot will extrapolate the plot outside the range of the data.

Sources: Federal Energy Regulatory Commission, FERC Form 1, “Annual Report of Major Electric Utilities, Licensees and Others”; Energy Information Administration, Form EIA-412, “Annual Report of Public Electric Utilities,” and predecessor survey forms; and Utility Data Institute.

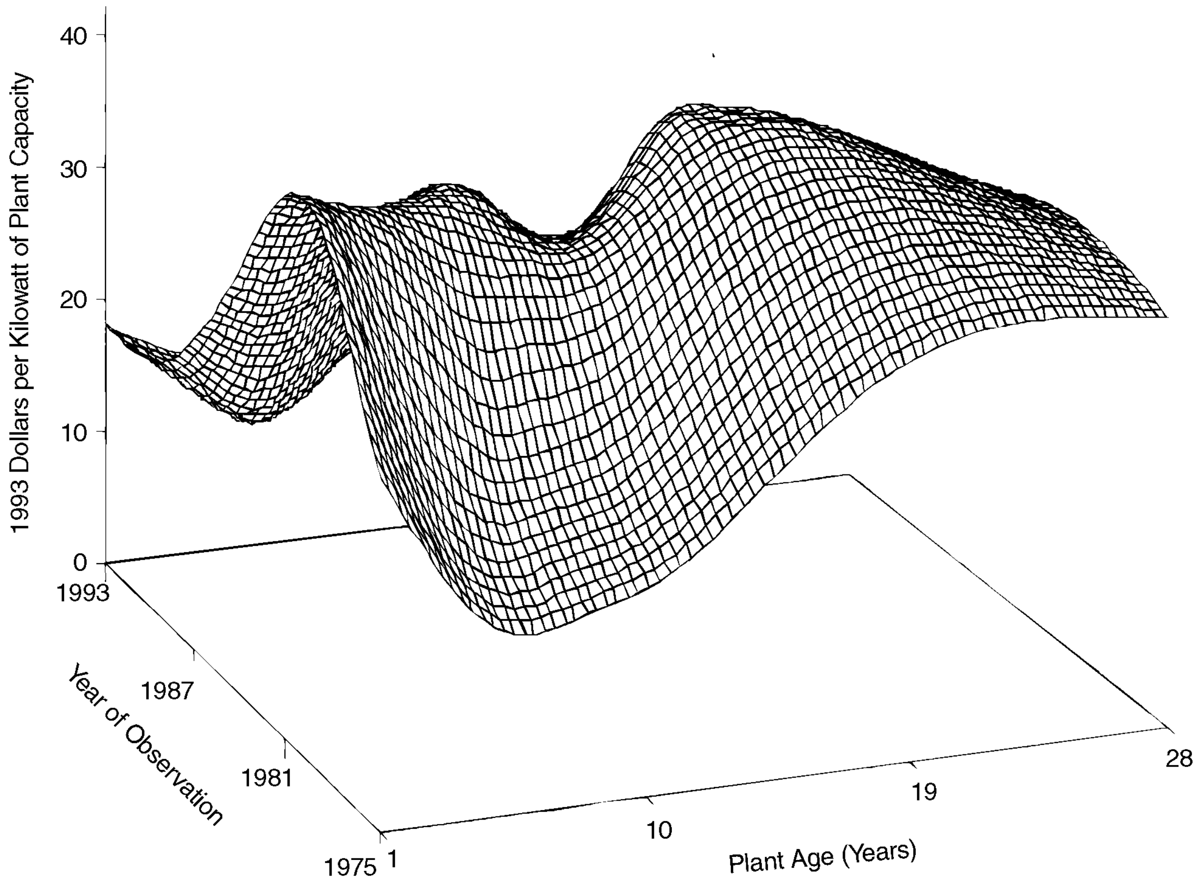
Additionally, any measure of NRC regulatory activity is highly correlated with industry experience, which was also increasing (Figure 9).[36] As discussed in detail in Chapter 3, it was not possible to obtain separate estimates of the industry learning and NRC regulatory effects. Thus, the best that could be done was to estimate the joint effect of these factors.

The second aspect of regulatory actions is the enforcement of existing regulations. Currently, the NRC issues a written Notice of Violation when a plant operator is not in compliance with a given regulation. Civil penalties are then considered for a plant operator who has significant or repetitive violations of NRC regulations. Finally, the NRC can issue a “cease and desist” order and even close a plant if the plant’s operator does not respond to civil penalties and the plant constitutes “a significant threat to public health and safety.” The objective of NRC’s enforcement is to provide incentives to insure compliance with regulations.

These fines are generally less than $100,000, which is very small relative to the total operating costs of a large utility. However, these fines often receive considerable

[36]That is, if industry experience and NRC regulatory actions were perfectly correlated, all the plants in Figure 9 would fall on the trend line. Since all the plants are very close to the trend line, the two series are highly, but not perfectly, correlated.

Figure 8. Surface Plot of Real Capital Additions Costs, Plant Age, and Year of Observation



Notes: Data have been deflated with the Gross Domestic Product Implicit Price Deflator. The sample consists of all plants with capacity over 400 megawatts in operation by the end of 1993. The mathematical algorithm used to smooth the data and generate the surface plot will extrapolate the plot outside the range of the data.

Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute.

attention in the local media, and, therefore, the possible adverse publicity could be more of an incentive to take corrective actions than the dollar amount of the fine.

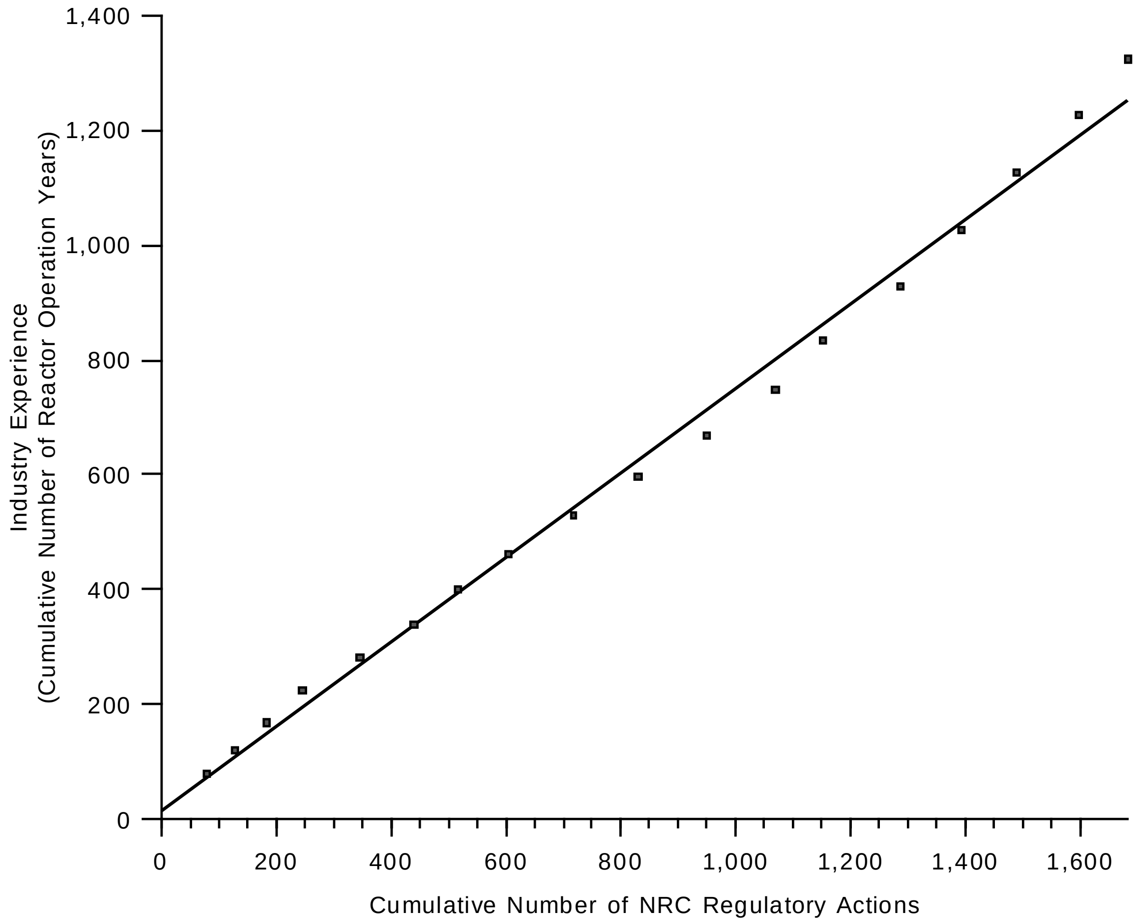
In this analysis, enforcement is measured by the dollar amount of each NRC fine. Figure 10 shows the total amount of NRC fines levied each year. These data suggest that this measure of NRC enforcement efforts increased until 1988 and then began to fall.[37] Table 7 shows tabulations of real O&M and capital additions costs against the cumulative dollar amount of NRC fines. This information suggests that plants receiving more fines have higher O&M costs. More importantly, the statistical analysis that controlled for all other factors, including plant size, also found that the greater the amount of the NRC fine, the greater the increase in O&M costs. Since such increases in cost probably reflect the expenses involved in taking corrective actions, the NRC's enforcement program is having its desired effect.

Economic and State Regulatory Incentives To Improve Performance

The third factor considered in this report is economic and State regulatory incentives to improve performance. Nuclear power plants were designed to operate in

[37]There are at least two reasons for this fall. First, if compliance was increasing over time, fewer plants will be in violation with the NRC regulations, and, therefore, fewer fines will be levied. Second, the fall could reflect reduced or redirected enforcement efforts.

Figure 9. Correlation Between Industry Experience and NRC Regulatory Activity



Note: The sample consists of all plants with capacity over 400 megawatts in operation by the end of 1993.
Sources: U.S. Nuclear Regulatory Commission, *Licensed Operating Reactors Status Summary*, NUREG-0020 (Washington, DC, various issues), and Nuclear Documents System (NUDOCS).

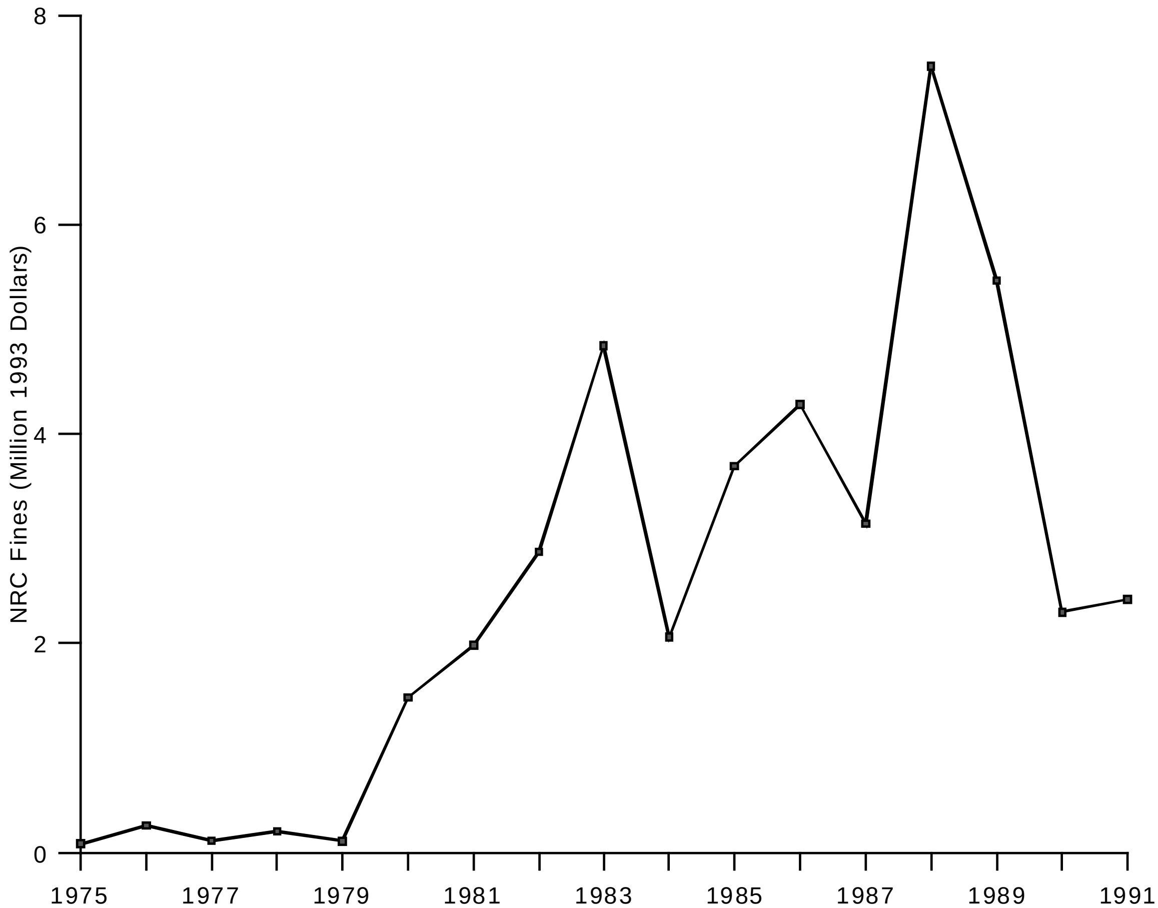
baseload—i.e., to operate continually—and, therefore, when the plant was out of service, replacement power would have to be obtained from another source. Over the entire 1974-1993 period, a typical nuclear power plant was out of service for about 100 days per year. Therefore, annual replacement power costs for a typical reactor would be roughly $25 million per year.[38] Replacement power costs are therefore substantial.

Increases in the price of replacement power provide an incentive to improve performance, and one way of improving performance is to increase O&M expenditures. One would, therefore, expect a positive correlation between the price of replacement power and real O&M costs.

Additionally, over the 1974-1993 period, all the power plants owned by investor-owned utilities were subject to cost-based regulation. Under this form of regulation, the utility can recover all prudently expended costs. It is well known that under such a regulatory scheme, the potential for cost disallowance is a major incentive to

[38]As a rough rule of thumb, replacement power costs are $250,000 per day. See James G. Hewlett, "The Operating Cost and Longevity of Nuclear Power Plants: Evidence from the USA," *Energy Policy* (July 1992), pp. 608-622.

Figure 10. NRC Fines by Year, 1975-1991



Note: The sample consists of all plants with capacity over 400 megawatts in operation by the end of 1993.

Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute.

minimize costs.[39] The greater the probability of cost disallowance, the greater the incentive to minimize costs. In this study, the ratings of the PUCs from an investor's viewpoint by Regulatory Research Associates (RRA), a major security research firm, were used to measure the probability of cost disallowances. PUCs with favorable ratings by this research firm tended to permit utilities to recover most of their costs, while ones with unfavorable ratings tended to disallow more of the costs.[40] Additionally, over most of the time period, the commissions focused on replacement power costs (as opposed to O&M costs). One would, therefore,

[39]See, for example, P. Joskow and R. Schmalansee, "Incentive Regulation of Electric Utilities," *Yale Journal of Regulation* (Spring 1987), pp. 1-49; and A. Kahn, *The Economics of Regulation: Principles and Practice* (New York, NY: John Wiley and Sons, 1971). Additionally, as will be noted in the next chapter, many nuclear power plants are subject to some type of incentive program. Such programs offer additional incentives to minimize costs.

[40]In fact, the amount of disallowances is a factor used by RRA in rating the PUCs. RRA had three basic ratings—Above Average, Average, and Below Average—and within each class, they had 3 subcategories. These rating were transposed into 5 values. The highest subclass in the Above Average category received a value of 1, and the lowest subclass in the Below Average category received a value of 5.

expect that the probability of disallowances of replacement power costs would be greater in States with stringent regulatory commissions, and this increased probability increases the incentives to improve performance by increasing O&M costs.

Table 8 shows tabulations of real O&M costs by year, the price of replacement power, and the stringency of the regulatory commission.[41] A surface plot of real O&M costs, the price of replacement power, and time is shown in Figure 11. A similar plot of real O&M

Table 7. Operating and Maintenance Costs and Capital Additions Costs by Cumulative Amount of NRC Fines, 1975-1992

Cumulative Fines[a]	O&M Costs[b]	Capital Additions Costs[b]	Cumulative Fines[a]	O&M Costs[b]	Capital Additions Costs[b]
0-20	37.01	23.64	400.1-500	72.10	30.58
20.1-40	56.54	31.80	500.1-600	75.87	22.89
40.1-60	60.14	32.94	600.1-700	102.64	41.95
60.1-80	68.75	28.31	700.1-800	103.98	31.59
80.1-100	83.95	20.39	800.1-900	102.62	37.25
100.1-150	71.75	32.19	900.1-1,000	94.23	68.64
150.1-200	76.95	27.00	1,000.1-1,100	110.56	44.23
200.1-250	85.49	33.19	1,100.1-1,400	96.71	43.26
250.1-300	85.89	35.54	>1,400	106.53	50.78
300.1-400	91.52	40.89	**Overall average**	**68.66**	**31.94**

[a]Thousand 1993 dollars.
[b]1993 dollars per kilowatt of plant capacity.
Note: Data have been deflated with the Gross Domestic Product Implicit Price Deflator.
Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute. U.S. Nuclear Regulatory Commission, *Annual Report to Congress* (Washington, DC, 1974 through 1992 editions).

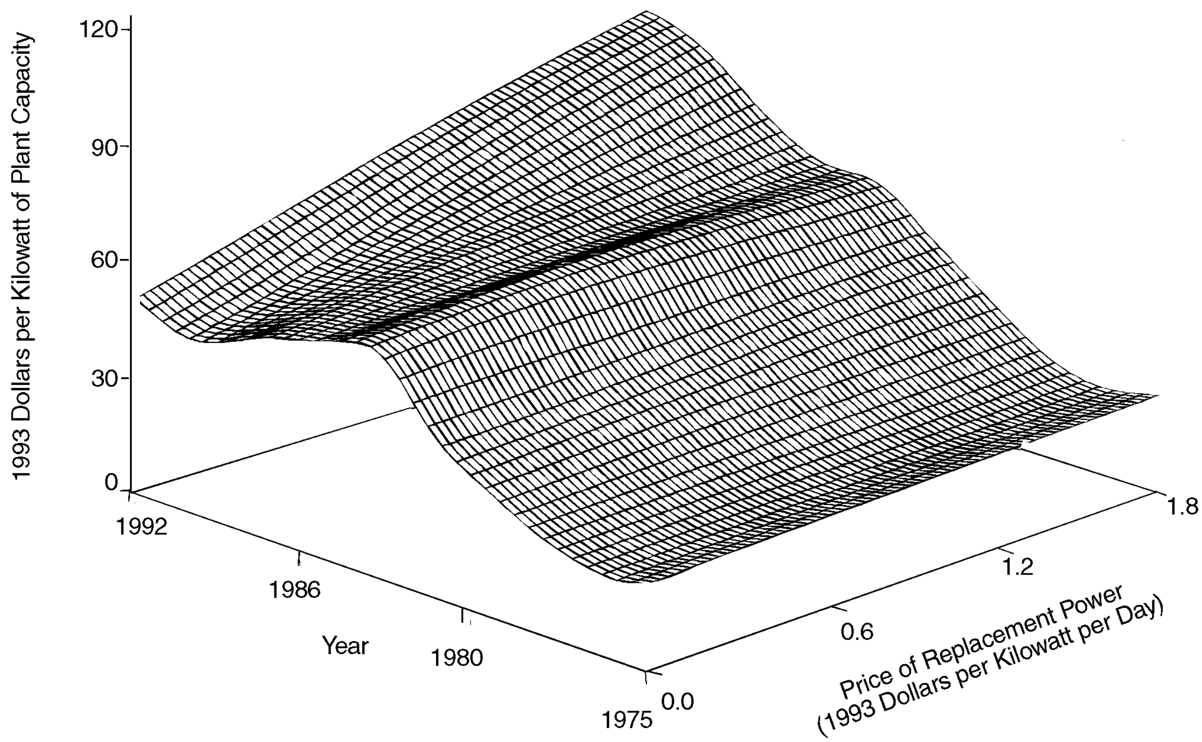
Table 8. Operating and Maintenance Costs by Price of Replacement Power and Regulatory Stringency, 1975-1984 and 1985-1992
(1993 Dollars per Kilowatt of Capacity)

Price of Replacement Power[a]	Regulatory Stringency					
	Lenient		Average		Stringent	
	1975-1984	1985-1992	1975-1984	1985-1992	1975-1984	1985-1992
<0.30	29.65	84.38	66.12	86.35	45.33	89.27
0.30-0.40	35.24	80.40	60.80	96.92	43.83	91.42
0.41-0.50	39.10	79.81	63.98	83.69	36.32	88.24
>0.50	48.21	90.96	55.97	116.06	51.40	100.78
Overall average . .	**38.65**	**84.42**	**59.83**	**97.60**	**44.32**	**92.52**

[a]Replacement power prices are in 1993 dollars per kilowatt of capacity per day.
Notes: Data have been deflated with the Gross Domestic Product Implicit Price Deflator.
Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; Utility Data Institute; U.S. Nuclear Regulatory Commission, *Replacement Power Costs for Nuclear Electric Generating Units*, NUREG/CR-4012 (Washington, DC, August 1987); and Regulatory Research Associates, *Utility Focus* (Jersey City, NJ, various issues).

[41]Here, the price of replacement power is measured in dollars per kilowatt of capacity per day. See Appendix A for details.

Figure 11. Surface Plot of Real Operating and Maintenance Costs, Time, and Replacement Power Costs



Notes: Data have been deflated with the Gross Domestic Product Implicit Price Deflator. The sample consists of all plants with capacity over 400 megawatts in operation by the end of 1993. The mathematical algorithm used to smooth the data and generate the surface plot will extrapolate the plot outside the range of the data.

Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute.

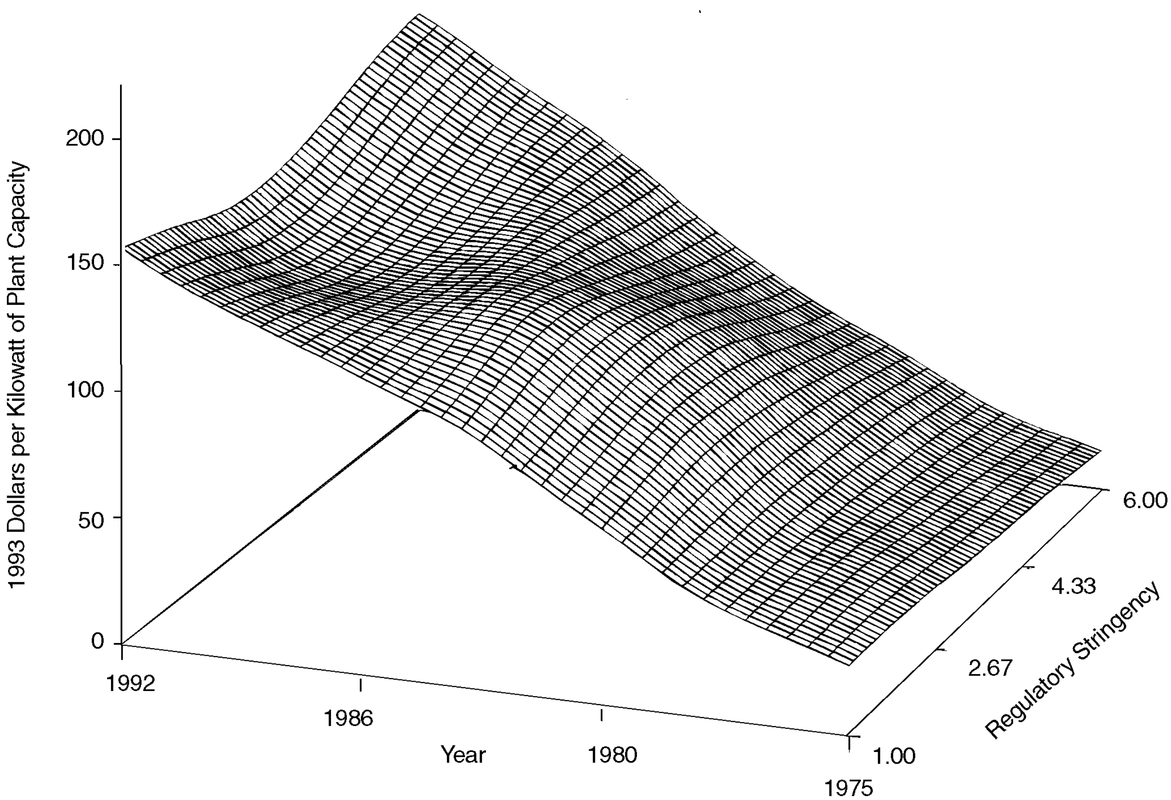
costs, the stringency of the PUC, and time is shown in Figure 12. This information suggests that the relationship among O&M costs, the price of replacement power, and the stringency of the PUC is not constant over time. In fact, this result was also obtained in the statistical analysis.

Summary

The discussion just presented suggests that there are four influences affecting costs that work in opposite directions. First, plant aging effects will cause costs to increase. Second, since utility and industry experience with this technology was increasing over time, learning effects will cause costs to fall. Third, the measure of NRC regulatory activity used here was increasing over the entire period. This would cause costs to increase. However, the NRC regulatory cost reduction initiatives mentioned in Chapter 2 could cause a decrease in the effect of this measure of regulatory actions on costs. Finally, replacement power costs increased until the mid-1980s and then began to fall (Figure 13). By itself, this would cause operating costs to increase and then to fall.

To summarize, the factors analyzed here tended to move in opposite directions. Thus, the reason for the moderation in costs depends upon the relative size of these influences—the subject of the next chapter in this report.

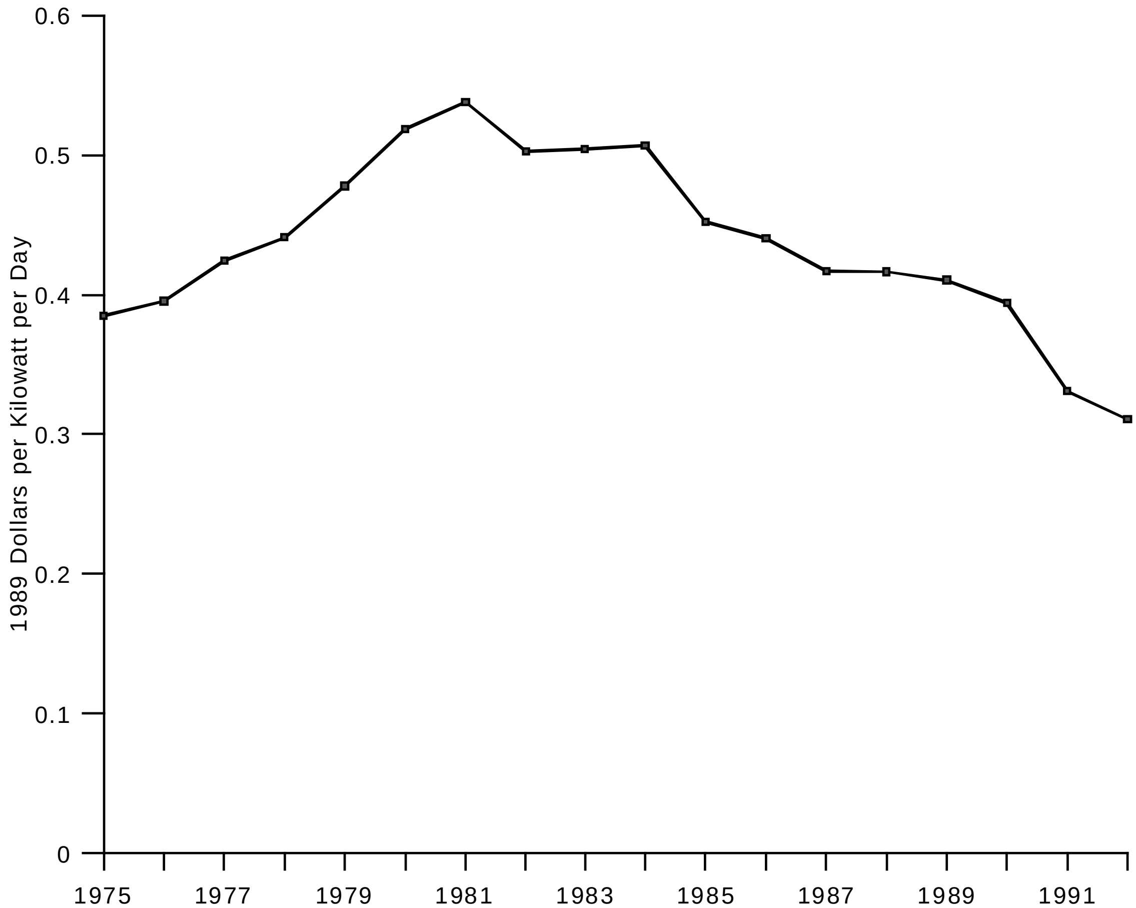
Figure 12. Surface Plot of Real Operating and Maintenance Costs, Time, and Regulatory Stringency



Notes: Data have been deflated with the Gross Domestic Product Implicit Price Deflator. The sample consists of all plants with capacity over 400 megawatts in operation by the end of 1993. See text for the definition of regulatory stringency. The mathematical algorithm used to smooth the data and generate the surface plot will extrapolate the plot outside the range of the data.

Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute.

Figure 13. Real Prices of Replacement Power, 1975-1992



Notes: Data have been deflated with the Gross Domestic Product Implicit Price Deflator.
Source: U.S. Nuclear Regulatory Commission, *Replacement Power Costs for Nuclear Electric Generating Units*, NUREG/CR-4012 (Washington, DC, August 1987).

3. Analysis of Nuclear Power Plant Operating Costs

This chapter examines the factors influencing O&M and capital additions costs. Over the past few years, utilities and State (and Federal) regulatory commissions have been examining the economics of the continued operation of many nuclear power plants. The decision to retire a nuclear power plant requires forecasts of O&M and capital additions costs over a long time period. As was noted in Chapter 2, the annual growth rates in O&M costs and the level of capital additions costs have fallen over the past few years. Utilities and State regulators look at industry-wide trends when preparing plant-level projections.[42] To determine if the trends will continue, an understanding of why these changes in costs have occurred is needed. This, of course, requires knowledge of the factors influencing costs.

O&M costs have escalated to the point where the long-run economic viability of many nuclear power plants is being challenged; therefore, industry and NRC initiatives to control costs are crucial. Again, to determine whether these factors actually caused the moderation in cost growth, one must know why costs have escalated in the past. If these factors did not cause the moderation in cost growth, then at some point costs may escalate again.

The organization of this chapter is as follows. The next section summarizes the methodology and describe the data, respectively. The remaining two sections present the results of the statistical analysis of O&M and capital additions costs.

Method Used To Analyze Plant Operating Costs

Nuclear operating costs were analyzed using multiple regression analysis. This commonly used statistical tool permits an examination of the variations in the dependent variable associated with changes in explanatory variables. The resulting regression coefficients and their associated statistics are direct measures of the effect of varying one independent variable while holding all other variables constant. For example, suppose that unit size (measured in kilowatts of installed capacity) is a factor influencing costs (expressed in dollars per kilowatt of capacity) and, therefore, is to be included in the regression analysis. If the resulting regression coefficient associated with unit size is 2, a 1-kilowatt change in plant size will be associated with a $2 variation in costs per kilowatt, holding all other factors constant.[43]

The standard error is a measure of the uncertainty in the associated regression coefficient. Suppose that the standard error associated with the unit size regression coefficient was 0.5. Then (roughly speaking) there is a 95-percent chance that the underlying coefficient is between 1 and 3.[44] If the regression coefficient is at least roughly twice its standard error, then the coefficient is said to be statistically different from zero. If a regression coefficient is, in fact, statistically different from zero, the associated factor of interest had a measurable impact on costs. Finally, the R-squared value gives an overall indication of how well the variation in the dependent variable is “explained” by the regression equation.

It is important to note that regression analysis can be used to demonstrate a statistical relationship between the dependent and independent variables. However, statements about cause and effect must be based on the conceptual model that underlies the selection of the explanatory variables.

The Model

The model used in the present report is derived in Appendix A.[45] According to this model, the following four factors will influence operating costs:

[42]See the testimony of Francis J. Murray, Commissioner, New York State Energy Office, and Charles Komanoff, Komanoff Energy Associates, before the New York State Assembly, Environmental Conservation Committee, Monday, September 26, 1994. This testimony dealt with the retirement of Indian Point 3, a 20-year-old reactor in New York State.

[43]Note that this description is literally valid only for linear regression.

[44]That is, the probability that the confidence interval 1 to 3 brackets the population regression coefficient is 95 percent.

[45]Note that this model is slightly different from the ones used the in 1988 and 1991 reports. The differences and estimates of the old model with more data are presented in Appendix A.

1. NRC regulatory activity and industry experience
2. Plant aging and utility / operator experience
3. Economic and State regulatory incentives to improve performance
4. The prices of inputs used to generate electricity from a nuclear power plant.

Although each of these factors will be discussed in detail below, one general comment about the model will be made here. The basic premise of this model is that nuclear power plant operations are influenced by engineering, regulatory, and economic considerations. These economic considerations suggest that there are tradeoffs between O&M expenditures, fuel, capital, and replacement power costs. For example, as was discussed in Chapter 2, the higher the price of replacement power, the greater would be the incentive to reduce the quantity of replacement power by improving plant performance. This can be accomplished by increasing real O&M expenditures. If the price of replacement power and O&M expenditures are positively correlated, then utilities are apparently trading off higher O&M costs for lower replacement power costs.

There are three reasons why it is important to recognize the possibility of such tradeoffs. First, as was just noted, statements about cause and effect must be based on a conceptual model, and if this conceptual model is wrong, inferences drawn from the statistical analysis are likely to be wrong. Second, by necessity, the NRC regulatory effects will be treated as a residual that remains after accounting for all other factors. If the model is not correctly specified, these residual effects could include the omitted factors. Third, the existence of such tradeoffs has implications about the control of O&M costs. If the industry initiatives to control costs result in decreased O&M costs at the expense of performance, then total production costs (including replacement power) may not decrease. If this were to occur, the cost containment programs could be counterproductive. This issue can only be addressed if such tradeoffs are explicitly captured in the model.

The Sample

There were 69 commercial plants in the database. The data covered the 1975-1992 period. The total numbers of observations used in the O&M and capital additions analyses were 854 and 750, respectively.[46] About 50 percent of the 46 plants that were operational by 1984 entered commercial operation after 1975. Additionally, over the 1985-1992 period, 23 additional plants entered commercial operation. Consequently, each plant does not have the same number of time-series observations.

Because data on 69 plants over about 17 years were used, there are factors that vary over time and therefore will influence variations in costs over time. Additionally, other variables are constant over time and will just influence variations in costs across plants at a given point in time. One difficulty in using such data is to disentangle the effects of the two types of variables.

Consider, for example, the effects of age on O&M costs. As was noted in Chapter 2, older plants tend to have higher O&M costs. This apparent correlation between age and costs could be due to the classic aging effects—i.e., as plants increase in age, O&M costs will increase because of “wear and tear.” There are also design differences in the different vintages of plants in the database that could possibly produce differences in O&M costs. If, as a result of such differences in design, the first plants that entered commercial operation had higher O&M costs, then older plants will tend to have high costs independent of aging effects. Such vintaging effects, as opposed to aging effects, could cause plant age and costs to be correlated.[47]

To disentangle the effects of the time-invariant factors from the time-varying ones, the data were transformed into deviations from the plant-specific means. This removed the effects of all time-invariant factors (such as plant vintage) that just affected the level, as opposed to the change, in costs.[48] By transforming the data into deviations from the plant-specific means, just the factors causing costs to change over time are examined.

Because the data were transformed from levels to changes over time, care must be taken in interpreting a number of coefficients. First, the only way that plant size can be increased is to add another unit at the same site. In the database used here, one additional unit was added at the same site in about 30 percent of the cases. Typically, that occurred in the first few years of the

[46]There are two reasons why the number of observations used in the O&M cost analysis is greater than the number used in the capital additions cost analysis. First, about 5 percent of the capital additions costs are negative. Since the natural logarithm of the capital additions cost is used, the observations with negative costs had to be excluded. Second, there are no capital additions costs for the first year the plant is operating.

[47]Since the age distribution of the plants is not consistent across regions, the same could be said for any time-invariant regional factor.

[48]This point is discussed in detail in Appendix A. In short, the so-called “fixed effects” model was estimated. In this model, the data are kept in level form and a series of 69 plant-specific dummy variables are included. With respect to the coefficient, this is equivalent to transforming the data into deviations from the plant-specific mean.

plant's operation. Except for such one-time increases, plant size does not vary over time. Thus, it is difficult to interpret the regression results presented in the text with respect to plant size. Estimates of the size effect using other estimating methods are presented in Appendix A. Second, there is little variation in the changes over time in the prices of O&M labor and materials. That is, although there is variability in their levels, these prices tend to change at roughly the same rate. Because of this lack of variability, the effects of changes in the prices of O&M labor and materials are sensitive to the model specification.

Analysis of Operating and Maintenance Costs

The results of the regression analysis on O&M costs are shown in Table 9. A linear equation was estimated with total nominal O&M costs as the dependent variable. These nominal O&M costs are the product of the staffing levels (and the quantities of O&M materials) and their respective labor wages (prices of O&M materials). The wage rates and prices of the O&M materials were also included as variables in the multiple regressions. Since prices are held constant, any resulting changes in the dependent variable caused by the other variables reflect variations in staffing levels (and O&M materials). In this sense, the effects of the factors discussed below represent "real" changes in costs.[49]

Additionally, some simple elasticities for the factors of interest are shown in Table 10. The elasticities indicate the relative size of the impact of the factor in question on real O&M costs. The effects of the three major factors—NRC regulatory activity and industry learning, plant aging, and economic incentives to improve performance—are discussed in turn.

NRC Regulatory Activity

After the NRC was established in 1975, there were substantial increases in regulatory activity. Prior to 1980, major changes in the regulations affecting plant designs occurred. These changes mainly affected construction costs and post-operational capital expenditures; their impacts on O&M costs were generally thought to be minor. However, in the 1980s, a large number of regulatory initiatives were imposed that affected the number of workers at nuclear power plants and, as a result, influenced O&M costs.

Part of the increased number of regulatory initiatives was the result of the March 1979 accident at Three Mile Island. This accident was due to both hardware failure (the pressurizer and a crucial gauge) and human error. In response to this accident, the NRC imposed additional regulatory requirements that affected the plant design and plant operations. The major TMI-related regulatory changes affecting plant operations and thus O&M costs dealt with increased training requirements for the reactor operators.[50] Moreover, as information about the technology accumulated, many additional requirements affecting plant operations were imposed. For example, after the loss of all feedwater at the Davis Besse plant in 1985, the NRC revised its procedures for evaluating the operational safety performance of nuclear reactor operators. An increase occurred in the number of inspections, in addition to the more traditional types of tests of the equipment and procedures. These factors affected maintenance and quality control activities. Moreover, the Systematic Assessment of Licensee Performance (SALP) program of the NRC indirectly placed additional requirements on utilities to improve performance by increasing O&M costs.[51]

Although these regulatory factors are important, their measurement is difficult. First, direct measures of the NRC regulatory effects do not exist. Second, the regulatory changes were not discrete, but rather were gradually changing over time. Therefore, another variable that approximated the effects of increased regulatory

[49]A number of other models were also estimated (see Appendix A for details). Note that the changes in real costs being examined in this chapter reflect changes in quantities. This is consistent with the standard economic definition of real costs. The data analyzed in Chapter 2 were deflated with the GDP Implicit Price Deflator and therefore, inflation-adjusted costs were examined. That notion of "real" is slightly different from the one used in economics and in this chapter.

[50]See M. Myers, L. Fuller, and H. Bowers, *NonFuel Operation and Maintenance Costs for Large Steam Electric Power Plants—1982,* ORNL/TM-8324 (Oak Ridge, TN: Oak Ridge National Laboratory, September 1982).

[51]This program resulted in quantitative measures of the safety-related performance of nuclear power plants.

Table 9. Results of the Operating and Maintenance Cost Analysis

Variable	Time Period and Measure of Regulatory Effects			
	1975-1992 Data			1975-1987 Data
	Cumulative NRC Actions[a]	Industry Learning[a]	Residual Costs[a]	Cumulative NRC Actions[a]
Plant Age	-285.114 (1,492.22)	1,140.86 (1,319.65)	108.777 (1,797.07)	802.559 (1,613.69)
Price of Replacement Power	2,922.1 (8,936.16)	5,222.67 (8,954.17)	1,749.03 (9,194.18)	34,268.5 (9,325.88)*
Price of Replacement Power × Stringency of Public Utility Commission	4,560.91 (2,735.76)*	4,237.39 (2,739.44)*	4,957.71 (2,793.71)*	581.055 (2,765.57)
Price of Replacement Power × Use of Fuel Adjustment Clause Dummy	-4,221.28 (8,651.46)	-6,105.82 (8,624.23)	-4,100.72 (8,931.69)	-17,369.8 (8,150.07)
Price of Replacement Power × Use of Fuel Adjustment Clause Dummy × Stringency of PUC	760.371 (3,264.25)	1,310.35 (3,260.22)	1,059.37 (3,354.5)	3,163.95 (3,124.14)
O&M Worker Wage Rate	348.649 (1,003.87)	723.138 (993.147)	-201.178 (1,145.43)	-675.193 (1,142.49)
Price of O&M Materials	-115.481 (220.688)	-196.095 (219.56)	-2.65597 (278.209)	-146.483 (205.039)
Fuel Price	124,504 (44,339.7)*	144,967 (45,162.2)*	114,061 (48,663.7)*	150,239 (49,457.5)*
Acquisition Price of Capital Good	-1,636.99 (570.754)*	-1,571.32 (572.788)*	-2,073.53 (626.873)*	-1,940.08 (688.253)*
Cost of Capital	23,571.4 (39,552.7)	34,508.4 (40,809.4)	-23,001.5 (51,798.6)	48,408.8 (42,934.3)
Change in Acquisition Price of Capital Good	2,496.52 (1,283.67)*	2,000.54 (1,287.39)	2,920.01 (1,526.92)*	1,076.5 (1,080.9)
NRC Regulatory Activity	39.6544 (13.6862)*	NA --	NA --	34.3333 (14.8046)*
Industry Learning	NA --	30.3829 (14.2108)*	NA --	NA --
Average NRC Fines to Year t-1	129.069 (24.649)*	130.642 (24.8001)*	128.042 (25.1633)*	138.251 (30.2713)*
Incentive Rate of Return Binary Variable	5,091.22 (2,694.28)*	5,673.04 (2,690.57)*	5,030.86 (2,725.77)*	2,329.24 (2,119.54)
Plant Size	16.7881 (4.47107)*	19.9328 (4.18798)*	17.7093 (5.06876)*	16.7313 (4.12145)*
Experience at Other Plants Owned by the Same Utility	256.99 (144.898)	243.052 (146.081)	271.852 (147.68)	-103.748 (203.155)
Retrofit Binary Variable	8,650.86 (3,472.93)*	9,106.12 (3,473.68)*	9,195.91 (3,517.63)*	5,042.91 (4,950.57)
O&M Costs in Year t-1	0.464712 (0.02864)*	0.4644 (0.02911)*	0.46438 (0.02976)*	0.507863 (0.03495)*
Constant	NA --	NA --	64,846.1 (32,443.7)*	NA --

See notes at end of table.

Table 9. Results of the Operating and Maintenance Cost Analysis (Continued)

Variable	Time Period and Measure of Regulatory Effects			
	1975-1992 Data			1975-1987 Data
	Cumulative NRC Actions[a]	Industry Learning[a]	Residual Costs[a]	Cumulative NRC Actions[a]
Year of Observation:				
1975	NA --	NA --	-66,044.3 (33,078.1)*	NA --
1976	NA --	NA --	-65,112.9 (31,221.5)*	NA --
1977	NA --	NA --	-64,449.2 (29,095.1)*	NA --
1978	NA --	NA --	-63,576.2 (27,089)*	NA --
1979	NA --	NA --	-60,812.3 (25,235.2)*	NA --
1980	NA --	NA --	-54,699.1 (23,225.7)*	NA --
1981	NA --	NA --	-52,025.9 (21,084.6)*	NA --
1982	NA --	NA --	-43,741.3 (18,926.4)*	NA --
1983	NA --	NA --	-40,829.7 (16,902.2)*	NA --
1984	NA --	NA --	-33,088.9 (15,121.1)*	NA --
1985	NA --	NA --	-32,963.9 (13,107.5)*	NA --
1986	NA --	NA --	-24,791.7 (11,426)*	NA --
1987	NA --	NA --	-20,436.7 (9,514.63)*	NA --
1988	NA --	NA --	-18,387.3 (7,958.99)*	NA --
1989	NA --	NA --	-15,188.2 (6,168.12)*	NA --
1990	NA --	NA --	-9,761.92 (4,576.57)*	NA --
1991	NA --	NA --	-6,676.69 (3,282.52)*	NA --
Adjusted R-Squared	0.89	0.87	0.87	0.89

[a]These are the estimates from the model that used the particular measure of NRC regulatory activity and industry learning effects.

Notes: Standard errors are shown in parentheses. An asterisk (*) indicates that the coefficient is significant at a 0.95 level of confidence, using a one-tailed test.

Sources: Federal Energy Regulatory Commission, FERC Form 1, “Annual Report of Major Electric Utilities, Licensees and Others”; Energy Information Administration, Form EIA-412, “Annual Report of Public Electric Utilities,” and predecessor survey forms; and Utility Data Institute.

Table 10. Simple Elasticities of Factors on Real Operating and Maintenance Costs

Factor	1975-1992 Data		1975-1987 Data	
	Coefficient	Elasticity	Coefficient	Elasticity
NRC Regulatory Actions	39.6544 (13.6862)*	0.50	34.3333 (14.8046)*	0.44
NRC Enforcement Actions	129.069 (24.649)*	0.04	138.251 (30.2713)*	0.04
Price of Replacement Power	13,094.6[a] (6,257.97)*	0.07	30,707.4[a] (7153.24)*	0.23
Stringency of State Regulatory Commission	1,787[a] (688.323)*	0.07	812.862[a] (799.71)	0.04
Use of Fuel Adjustment Clause	-835[a] (1,838.26)	-0.01	-3,405.56[a] (1,532.61)*	-0.04
Plant Age	-285.114 (1,492.22)	-0.04	802.559 (1,613.69)	0.15
Price of O&M Labor	348.649 (1,003.87)	-0.93	NA --	-1.12
Price of Capital	-1,636.99 (570.754)*	-0.40	-1,940.08 (688.253)*	-0.61
Price of Fuel	124,504 (44,339.7)*	0.09	150,239 (49,457.5)*	0.15

[a]Coefficient and standard errors computed at means.

Notes: Standard errors are shown in parentheses. An asterisk (*) indicates that the coefficient is significant at a 0.95 level of confidence, using a one-tailed test. All elasticities were estimated as means. See Appendix A for estimates using other models.

Sources: Federal Energy Regulatory Commission, FERC Form 1, “Annual Report of Major Electric Utilities, Licensees and Others”; Energy Information Administration, Form EIA-412, “Annual Report of Public Electric Utilities,” and predecessor survey forms; and Utility Data Institute.

activity had to be used. In this analysis, the number of changes in “regulations” was employed.[52]

The NRC has two types of regulatory vehicles that can be used to effect changes in the operations (including maintenance) of nuclear power plants. One vehicle is formal changes to regulations, as found in the Code of Federal Regulations (CFR). These changes must be approved by a majority of the Commissioners after considering public comments. Table 11 shows tabulations of the number of changes in the relevant parts of the CFR, and the number of associated Regulatory Guides. (Regulatory Guides explain the details of a given change in the CFR.) Most of the formal changes in the CFR occurred in the late 1970s to early 1980s (Table 11). Some, but not all, of this growth in NRC regulations was in response of the March 1979 accident at Three Mile Island.[53]

Second, the NRC can also influence maintenance activities by issuing regulatory bulletins, generic letters, and information notices. These letters and notices transmit safety-related information of concern to the NRC. Unlike the changes in the CFR, utilities are not legally required to respond to the safety concerns found in these letters and notices.[54] (In fact, many of these bulletins are not approved by the Commission and are not subject to any public comment.) However, most utilities tend to follow the suggestions found in these notices and letters. These less formal regulatory actions

[52]In other analyses of nuclear power plant construction costs, variables such as cumulative size of the nuclear industry and a simple time trend variable were employed. See Energy Information Administration, *An Analysis of Nuclear Power Plant Construction Costs*, DOE/EIA-0485 (Washington, DC, 1986); R. Cantor and J. Hewlett, “The Economics of Nuclear Power: Further Evidence on Learning, Economies of Scale, and Regulatory Effects,” *Resources and Energy*, Vol. 10 (1988), pp. 315-335; and Energy Information Administration, *An Analysis of Nuclear Power Plant Operating Costs*, DOE/EIA-0511 (Washington, DC, 1988). Compounding this measurement error problem is the fact that any measure of NRC regulatory activity will be highly correlated with industry experience since both were increasing over time. Thus, even if the NRC regulatory actions could be measured, because of multicollinearity, the regulatory and industry learning effects could not be disentangled. Note that similar measures were used in analyses of other regulated industries. Additionally, as will be discussed below, time itself was used.

[53]See for example, Energy Information Administration, *An Analysis of Nuclear Power Construction Costs*, DOE/EIA-0411 (Washington, DC, May 1988).

[54]See U.S. Nuclear Regulatory Commission, *Annual Report to Congress*, NUREG-1145, Vol. 10 (Washington, DC, 1990).

Table 11. Measures of NRC Regulatory Activity

Year	Changes to CFR[a]	New Regulatory Guides	New Regulatory Bulletins	New Information Notices[b]	Total
1975	0	37	10	0	**47**
1976	0	39	11	0	**50**
1977	0	47	8	0	**55**
1978	11	36	15	0	**62**
1979	7	21	34	38	**100**
1980	14	6	28	46	**94**
1981	17	15	5	39	**76**
1982	19	5	7	58	**89**
1983	14	5	9	85	**113**
1984	12	2	4	96	**114**
1985	8	4	3	104	**119**
1986	5	3	0	112	**120**
1987	7	6	2	68	**83**
1988	12	5	14	103	**134**
1989	8	5	3	90	**106**
1990	3	4	2	88	**97**
1991	5	5	1	96	**107**
1992	0	17	3	66	**86**

[a]Before the U.S. Nuclear Regulatory Commission (NRC) was established in 1975, its predecessor, the Atomic Energy Commission, codified changes in regulations. The changes were also implemented with new Regulatory Guides.

[b]Includes generic letters.

Source: U.S. Nuclear Regulatory Commission, Nuclear Documents System (NUDOCS).

grew at a roughly constant rate throughout the 1980s (Table 11).[55]

The results in Tables 9 and 10 show that there is a strong correlation between the cumulative number of NRC regulatory actions and real O&M costs. A 1-percent increase in NRC regulatory actions was associated with a 0.5-percent increase in real O&M costs. Thus, this measure of the regulatory effects is substantial.

There was no absolute or relative decrease after 1987 in the measure of regulatory activity used here. However, the NRC's initiatives to control costs could possibly be reflected in a decrease in the effect of a given change in regulatory activity (i.e., the regression coefficient associated with the NRC regulatory activity variable).[56] To examine this issue, the model was reestimated with data ending in 1987. As can be seen from Tables 9 and 10, the estimated regulatory effects actually increased when the post-1987 data were used. However, this increase was not statistically significant.[57] Thus, there is no evidence that the effects of increases in NRC regulatory activity, as measured by the cumulative number of NRC actions, decreased after 1986.

The Residual Escalation in Real Operating and Maintenance Costs

The model can also be used to estimate the yearly changes in costs after controlling for all observable factors except NRC regulatory activity and industry learning. This residual escalation in real O&M costs will be the result of NRC regulatory activity, industry learning, and all other relevant but unmeasurable

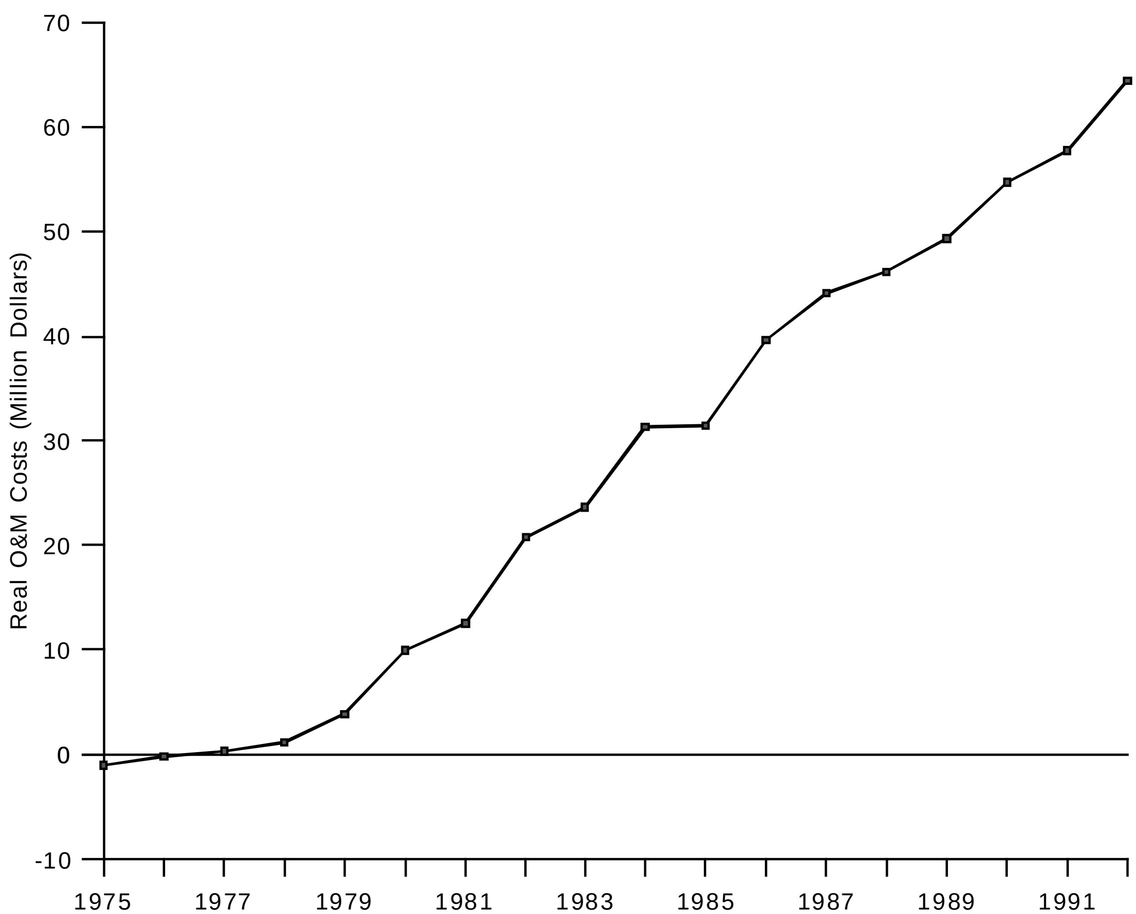
[55]Additionally, in response to the March 1979 accident at Three Mile Island, the Institute of Nuclear Power Operations (INPO) was founded. This organization provides information and research support to improve the safety and performance of U.S. nuclear power plants. Some have argued that the NRC has delegated some of their safety-related regulatory responsibilities to INPO. More importantly, the information provided by INPO is not available to the public. If, in fact, INPO is acting as a regulatory body, it is impossible to measure any resulting impacts.

[56]It is also possible that in the late 1980s and early 1990s, an increasing number of these actions were not related to O&M costs.

[57]A version of the model was estimated that included a binary variable equaling 1 if the year of the observation was after 1986. This binary variable was interacted with the regulatory variable. The resulting interaction term measures the change in the NRC regulatory effect and was statistically insignificant.

factors not considered in the model.[58] The cost control initiatives described above are intended to lower costs while maintaining the same level of safety. Thus, if these initiatives are having their desired outcomes, the residual escalation in costs should decrease. That is, their effect should be independent of aging and prices. The "residual" escalation in real O&M costs—i.e., the increase in costs after accounting for all other measurable factors—is plotted in Figure 14.[59] This second indirect measure of NRC regulatory activity and industry learning (i.e., time) suggests that the escalation in regulation-induced costs was lower in the 1970s than

Figure 14. Residual Escalation in Real Operating and Maintenance Costs, 1975-1992



Note: These data show the increase in costs after controlling for all factors other than regulation and learning, computed from the regression results shown in Table 9.

Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute.

[58]One could estimate the model in a given year without any measure of NRC regulatory activity and based upon these estimates compute the predicted amount of escalation. The difference between the predicted and actual amount of escalation for that year would be due to all omitted factors, including NRC regulatory activity. Statistically, this was accomplished by replacing the NRC regulatory variable with a series of yearly dummy variables.

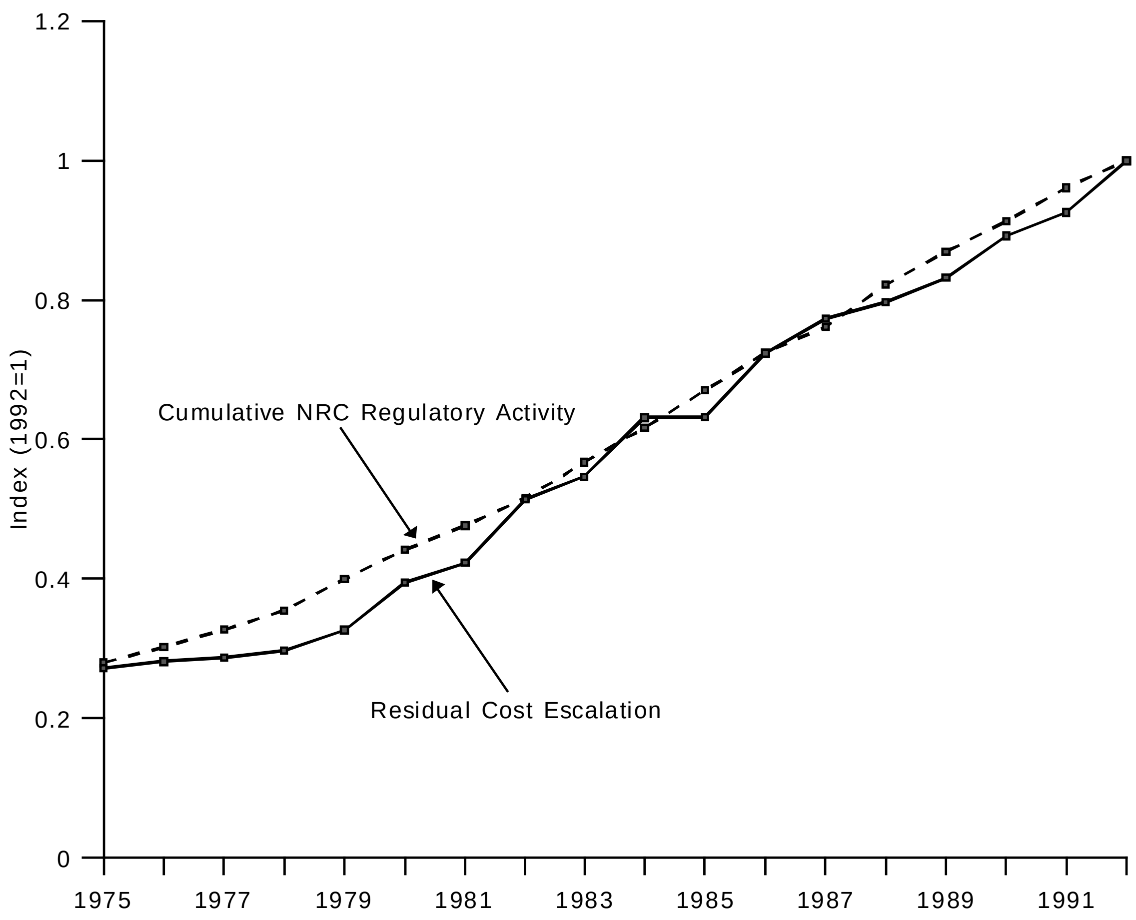
[59]These data were directly computed from the regression results in column 3 of Table 9. In particular, the reference year was 1992, and therefore the constant term was the amount of residual escalation for that year. The residual escalation for the other years was computed by subtracting the constant term from the relevant coefficient shown in Table 9.

in the 1980s. Over the decade of the 1980s, after controlling for all other factors other than regulation and learning, real O&M costs were increasing by $4 million to $5 million per year. This escalation in O&M costs is substantial.

More importantly, in the late 1980s and early 1990s, when real O&M costs began to level off, the residual escalation in O&M costs increased at roughly the same absolute rate. This observation has two implications. First, if the NRC's cost control programs are having an effect that is independent of the other variables in the regression, it is being masked by other, unmeasurable factors. Second, if this "residual" escalation in O&M costs is capturing the regulatory effects, the leveling off in O&M costs was due to factors other than regulation.

An index of the cumulative number of NRC actions and the residual escalation in O&M costs is shown in Figure 15. The time paths of the residual escalation in O&M costs and the increases in NRC regulatory actions increased at a roughly constant percentage rate over the entire 1975-1992 period. This observation suggests that both "measures" of regulation are capturing the same underlying cost drivers.

Figure 15. Indices of Residual Cost Escalation and Cumulative NRC Regulatory Activity, 1975-1992



Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute.

Industry Learning Effects

Two influences other than regulation, which are highly correlated with time, are related to changes in productivity. First, the residual escalation in the costs could be due in part to the general decline in utility industry productivity occurring over the 1970s and 1980s.[60] Second, if significant "learning-by-doing effects" were present because of increased industry experience, then this might have compensated for the productivity-induced cost increases. If the productivity effects were on balance negative (i.e., caused costs to fall), then the regulatory effects will be overstated.

Because any measures of NRC regulatory activity and industry learning were highly correlated, separate measures of the two effects could not be obtained (see Figure 9 in Chapter 2). A third specification of the model, which included only the cumulative number of industry reactor operation years as a measure of industry experience, was estimated. As Table 9 shows, the industry learning coefficient is positive and statistically significant. A 1-percent increase in experience caused a 0.3-percent increase in costs. In terms of elasticities, these effects are slightly smaller than the regulatory impacts.

A recent analysis of nuclear power plant performance found that plant operators only benefit from increased experience with older plants and older plants of the same design. That is, the analysis found a positive correlation between the number of reactor operation years of experience with older plants and performance. The authors of that study provided these measures of learning, which were used in the present analysis. Their results were similar to the ones presented in Table 9.[61]

There are two explanations for these results. First, since the other coefficients are similar to the ones in the specification that just included a regulatory variable, the industry experience variable could be capturing both the learning and the regulatory effects. The positive coefficient suggests that the regulatory effects are greater than the learning effects. Second, others have recently argued that the learning effects may be positive.[62] That is, increased industry experience could possibly lead to the increased accumulation of scientific information about the technology. This increased information could, in turn, result in design changes, new operating procedures, increased maintenance requirements, and increased regulatory requirements. All of these factors could actually cause costs to increase. The positive industry learning coefficient is consistent with this hypothesis.

NRC Enforcement Efforts

Since the NRC has no prescriptive regulations on how a utility must maintain a nuclear power plant, it does not directly regulate a utility's maintenance of a nuclear power plant.[63] Instead, the NRC establishes a series of guidelines affecting the general operation (including maintenance) of the power plant, and a utility has a great deal of flexibility in meeting these guidelines.

Given the NRC's method of regulating the operations of U.S. nuclear power plants, enforcement issues are important. The average amount of the NRC fines will be used to measure the effects of their enforcement program. The results of the regression analysis shown in Table 9 indicate that plants receiving higher average fines will cause real O&M costs to increase. However, from Table 10, the effects of the NRC's enforcement program are relatively small. A 1-percent increase in the average fines will only lead to a 0.03-percent increase in real O&M costs. Thus, the effects of increases in NRC regulatory actions are much greater than the effects of increases in the enforcement efforts.

Plant Aging and Utility Learning Effects

Before presenting the results of the aging analysis, three points need to be discussed. First, the aging effects could be reflected in O&M costs and / or plant performance. There is a direct relationship between O&M costs and performance—the higher the O&M costs, the better the performance of a nuclear power plant.[64] Thus, if utilities increase maintenance expenditures as plants age, then one might not observe an age-related deterioration in performance. Conversely, if utilities do not

[60]See, for example, Energy Information Administration, *An Analysis of Nuclear Power Plant Construction Costs,* DOE / EIA-0485 (Washington, DC, 1986).

[61]See R. Lester and M. McCabe, "The Effect of Industry Structure on Learning by Using in Nuclear Power Plant Operation," *RAND Journal of Economics* (Autumn 1993), pp. 418-439.

[62]See V. Gilinsky, "Nuclear Safety Regulation: Lessons from the United States," *Energy Policy* (August 1992), pp. 704-712; and G. McKerron, "Why Do Nuclear Costs Keep Rising," *Energy Policy* (July 1992), pp. 641-653.

[63]This is to be contrasted with the Federal Aviation Administration's regulation of the maintenance of commercial aircraft. See U.S. Nuclear Regulatory Commission *Status of Maintenance in the US Nuclear Power Industry*, NUREG-1212 (Washington, DC, June 1986), and "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," *Federal Register*, Vol. 56, No. 132 (July 10, 1991).

[64]See Energy Information Administration, *An Analysis of Nuclear Power Plant Operating Costs: A 1991 Update*, DOE / EIA-0547 (Washington, DC, 1991), for more details.

do so, then one should observe a deterioration in performance as plants age. The empirical evidence on the effects of age on nuclear power plant performance is mixed. However, the bulk of the evidence, including the most recent and complete study, seems to suggest that performance falls as plants age. Additionally, all the studies of the performance of coal-fired power plants found evidence of aging.[65] If it is, in fact, the case that performance does fall as plants age, then one might not observe any relationship between aging and O&M costs.

Second, as was noted above, only commercial (as opposed to demonstration) power plants were included in the sample of plants used here.[66] The first nuclear power plant considered to be commercial was Connecticut Yankee, which entered commercial operation in 1967. The first major "wave" of commercial nuclear power plants entered commercial operation in the early 1970s. Thus, the 1992 ages of the oldest and average plant in the sample were 25 years and 14 years. Because the nuclear technology is still relatively young, a sample of relatively young plants was used. Consequently, inferences about the aging effects of older plants based on a sample of relatively young ones may be misleading.

Third, recent analyses of nuclear power plant performance have noted the importance of distinguishing between operator-specific, utility-specific, and industry-wide learning.[67] The same is done here. Since plant age and operator / utility experience are almost identical, the age coefficient could be either positive or negative, depending on whether the positive plant aging effect outweighs the negative operator / utility-specific learning effect.

Additionally, industry observers have noted that some utilities can deal with the NRC more easily than others. It is possible that as a utility's experience increases, it can comply with a given set of NRC regulations at lower cost. Thus, as experience increases, costs could fall because of increased knowledge about the technology and about the NRC.

The results of this analysis suggest that measurable positive aging effects do not exist, since the age coefficient is always statistically insignificant (Table 9). There are two possible explanations for this result. First, the utilities might have made the rational decision to let performance deteriorate as plants age, in which case O&M costs would be invariant to age. Second, the age coefficient measures the combined effect of plant aging and operator-specific (and utility-specific) learning. The negative learning effects could possibly have offset any positive aging effects. Note that by the end of 1992, the average age of all plants used here was about 14 years, or roughly about 40 percent of the 40-year design life. According to the conventional wisdom, most of the learning occurs early in a plant's life. Given that the average plant is rather young, it very well could be the case that the learning effects offset any aging effects.[68]

Approximately 35 percent of all U.S. nuclear power plants are owned by a utility that also operates other nuclear plants. However, there is also little evidence that utilities benefit from experience of other plants that they own. That is, the "experience of other plants owned by the same utility" coefficient is statistically insignificant. It is also interesting to note that a similar result was obtained when the experience with other older plants and older plants with the same design was used. Additionally, of the 12 utilities that own more than one plant, the largest is Commonwealth Edison, which owns 6 nuclear plants (13 units) and is the largest nuclear utility in the United States. Separate learning effects were estimated for Commonwealth Edison and the other utilities owning more than one plant. In this case, there was still no evidence that increased experience with other plants caused costs to fall.

[65]See R. Lester and M. McCabe, "The Effect of Industry Structure on Learning by Using in Nuclear Power Plant Operation," *RAND Journal of Economics* (Autumn 1993), pp. 418-438; M. Gielecki and J. Hewlett, "Commercial Nuclear Electric Power in the United States: Problems and Prospects," *Monthly Energy Review*, DOE / EIA-0035(94 / 08) (Washington, DC, August 1994); and James G. Hewlett, "The Operating Cost and Longevity of Nuclear Power Plants: Evidence from the USA," *Energy Policy* (July 1992), pp. 608-622.

[66]The only two plants in operation over the 1975 to 1989 period that were excluded were Big Rock Point and Yankee Rowe, with capacities of 65 and 175 megawatts, respectively. Additionally, Shippenport was excluded because it was owned and operated by the U.S. Department of Energy.

[67]Lester and McCabe argued that the impact of flows of information within a plant, between various plants owned by one utility, and between utilities will be different. See, R. Lester and M. McCabe, "The Effect of Industry Structure on Learning by Using in Nuclear Power Plant Operation," *RAND Journal of Economics* (Autumn 1993), pp. 418-438.

[68]As noted above, there is a substantial amount of multicollinearity between age and any of the regulatory / industry learning variables. To determine whether the insignificant aging effect was the result of multicollinearity, a version of the model that excluded age was estimated. All the resulting coefficients were similar to the ones when age was included. This result suggests that the negative aging effect was not the result of multicollinearity.

Economic and State Regulatory Effects

This analysis explicitly recognizes that there are both costs and benefits associated with improved plant performance. One of the major benefits of improved performance is the reduction in the need for replacement power when the plant is out of service. Thus, increases in the price of replacement power provide an incentive to reduce the use of replacement power by improving plant performance. Such increases can be accomplished by improving the plant's maintenance (i.e., by increasing O&M costs). Thus, increases in the price of replacement power could result in increased O&M costs.[69]

The owners of most U.S. nuclear plants are subject to State rate-of-return regulation; therefore, most of the operating costs, including fuel, replacement power, and O&M, are recovered on a dollar-for-dollar basis. Given that rate-of-return regulation has this element of "cost-plus contracting," utilities may not have an incentive to minimize costs. Stated differently, given that most of the costs can be recovered on a dollar-for-dollar basis, the market price of an input may not be the true price observed by the utility. (For example, in the limit, if the utility can recover all the fuel costs, the utility might perceive fuel to be a free good with a zero price.)

There are two facets of rate-of-return regulation that will induce cost-minimizing behavior. First, Kahn and others have noted that when prices are increasing, regulatory lag—the time difference between when a rate increase is warranted and when it is granted—will induce utilities to minimize costs.[70] Over most of the time period, the State commissions focused on the recovery of fuel and replacement power costs. In some States these costs can be recovered with a one-month lag by means of a Fuel Adjustment Clause (FAC). In other States, the utility must file a formal and lengthy rate request. When prices are increasing, the longer the regulatory lag, the greater would be the incentive to improve performance by increasing maintenance expenditures. In the present analysis, a variable was used that took on the value of 1 if the plant was located in a State with an FAC and 0 otherwise.[71]

Second, these costs are scrutinized by the State regulatory authorities and will be disallowed when they are viewed to be excessive. The greater the regulatory scrutiny as measured by RRA's rating of the PUCs, the less will be the certainty of cost recovery. The increased probability of cost disallowance will increase the incentive to reduce replacement power costs by increasing O&M expenditures.

The price of replacement power, the stringency of the regulatory commission, and the use of an FAC possibly could jointly affect real O&M costs. For example, the combination of low replacement power costs, very lenient regulatory commissions, and the rapid recovery of fuel costs could jointly cause real O&M costs to be lower. To capture these joint effects, two variables—the product of the price of replacement power with the use of an FAC and the stringency of the PUC—along with a third one, the product of all three factors, were also included.

The results of the regression analysis shown in Table 10 suggest that *on average* both the price of replacement power and the stringency of the regulatory commission independently were positively correlated with real O&M costs.[72] That is, both increases in the price of replacement power and the probability that replacement power costs will be disallowed increased the incentives to improve performance by increasing O&M costs. However, there is no measurable difference in the real O&M costs for plants located in States with an FAC relative to ones located in States without an FAC. These results, therefore, suggest that over the entire 1975-1992 period, the certainty as opposed to the speed of cost recovery affected the incentives to minimize costs.

The joint effects of changes in the price of replacement power and the stringency of the State public service commission on real O&M costs are shown graphically in Figures 16 and 17. Figure 16 shows the relationship

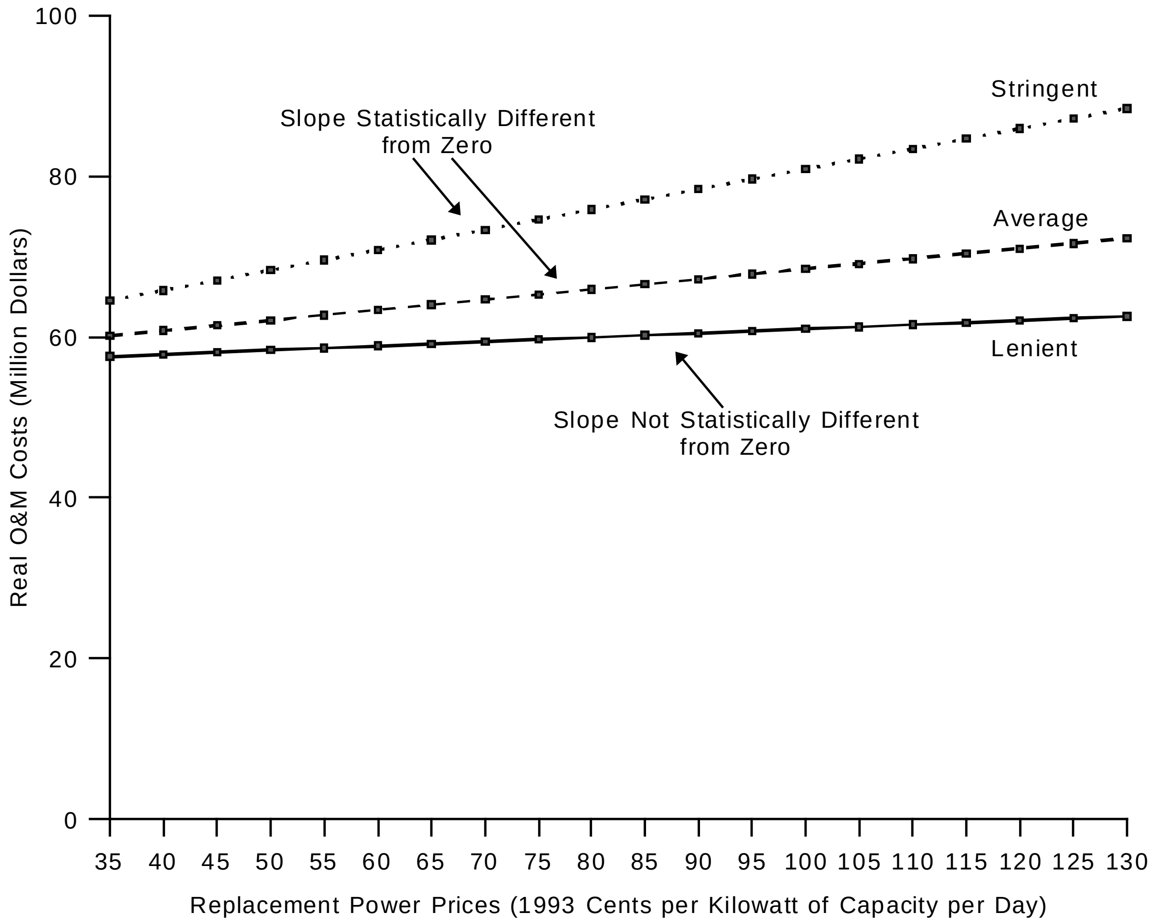
[69]Issues dealing with expected future prices are discussed in Appendix A.

[70]See P. Joskow and R. Schmalansee, "Incentive Regulation of Electric Utilities," *Yale Journal of Regulation* (Spring 1987), pp. 1-49; and A. Kahn, *The Economics of Regulation: Principles and Practice* (New York, NY: John Wiley and Sons, 1971).

[71]In the 1988 report, to measure the speed of recovery (i.e., the first State regulatory factor), a variable was used that took on the value of zero if the plant was located in a State with an FAC and the number of days between when the rate request was formally filed and when it was formally settled. However, in that analysis, this variable was never statistically significant. There were two reasons for this result. First, with a few exceptions, there was only a modest amount of variation in the measure of regulatory lag used here. Second, the correct definition of regulatory lag is the difference between when a price increase was warranted and when it was allowed. The date when the rate case was formally submitted to the commission was used as a proxy for the date when the rate increase was warranted. This proxy was no doubt a poor one. See Energy Information Administration, *An Analysis of Nuclear Power Plant Operating Costs,* DOE/EIA-0511 (Washington, DC, 1988).

[72]The elasticities and coefficients were computed at the means of the respective variables. As will be noted below, the price of replacement power in not statistically significant when the State PUC is also very lenient.

Figure 16. Effects of Replacement Power Prices in Three State Regulatory Environments



Notes: The slopes of the three lines are 5.65, 13.10, and 25.51. The standard errors are 6.5, 6.3, and 8.4, respectively.

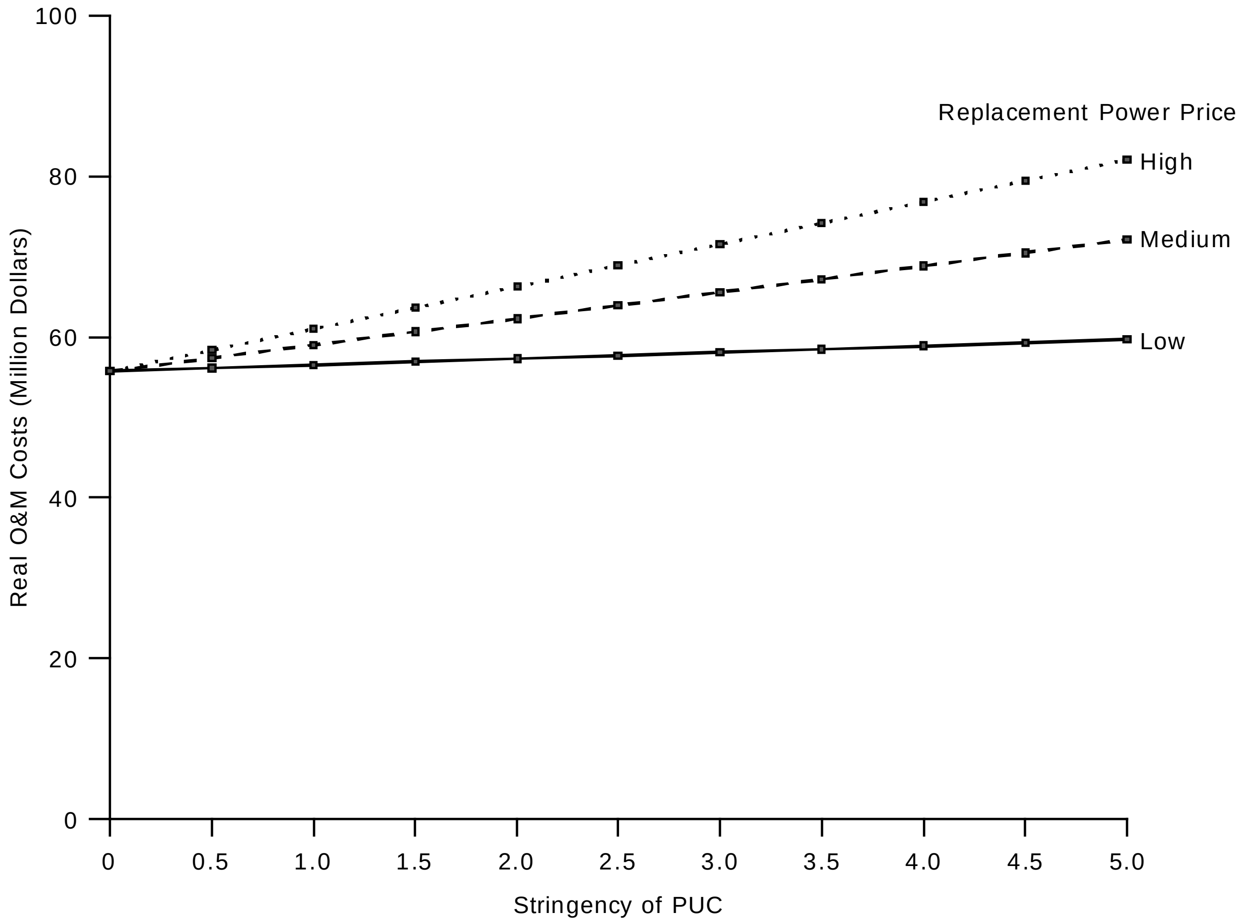
Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute. U.S. Nuclear Regulatory Commission, *Replacement Power Costs for Nuclear Electric Generating Units*, NUREG/CR-4012 (Washington, DC, August 1987).

between the price of replacement power and real O&M costs as a function of the stringency of the PUC. Similarly, Figure 17 shows the relationship between the stringency of the PUC and O&M costs as a function of the price of replacement power. These relationships were computed directly from the regression results reported in Table 9.

A small increase in the price of replacement power would not have a statistically significant effect on real O&M costs if the plant was located in a State with a very lenient regulatory commission (Figure 16). The average rating of all PUCs with nuclear plants was about 2.5. If the plant was located in such a State, increases in the price of replacement power would cause real O&M costs to increase. Moreover, from Figure 17, at any given replacement power price, a small increase in the stringency of the PUC would cause real O&M costs to increase.

These results suggest that increases in the penalty for poor plant performance, as measured by the price of replacement power, does represent an increased incentive to improve plant performance by increasing O&M costs. However, this is not true if the plant is located in a State with a relatively lenient PUC. Thus, if the

Figure 17. Effects of State Regulatory Environment With Three Replacement Power Prices



Notes: The higher the number on the x-axis, the more stringent is the State Public Utility Commission. The slopes of the lines are 0.532, 1.669, and 5.321. The standard errors are 0.229, 0.688, and 2.295, respectively.

Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute. U.S. Nuclear Regulatory Commission, *Replacement Power Costs for Nuclear Electric Generating Units*, NUREG/CR-4012 (Washington, DC, August 1987).

probability of full cost recovery is very high, increases in the price of replacement power do not offer much of an incentive to improve performance, simply because the costs can be passed through to consumers.

As a result of the disincentives inherent in cost-based regulation, many nuclear power plants are now subject to incentive rate-of-return programs that reward utilities for good performance and penalize them for poor performance.[73] Such programs represented an incentive to improve performance by improving the plant's maintenance. Initially, both the actual dollar amount of the reward and a simple variable taking on the value of 1 if the plant was subject to an incentive rate-of-return program were used in the analysis. Both specifications yielded similar results. In the results presented here, a variable taking on the value of 1 if the plant was subject to an incentive rate-of-return program was used.

[73]See U.S. Nuclear Regulatory Commission, *Incentive Regulation of Nuclear Power Plants by State Public Utility Commissions*, NUREG/CR-5509 (Washington, DC, 1990), and subsequent updates.

The results of the regression analysis suggest that plants located in States with incentive rate-of-return programs have real O&M costs that are roughly $5 million higher than those for identical plants located in States with no incentive program (Table 9). Thus, these incentive programs do appear to represent an additional incentive to improve performance by increasing real O&M costs.

Changes in the Effects After 1986

There were some changes in the relationship between economic and State regulatory incentives to improve performance and O&M costs over the 1987-1992 period. Over the 1975-1987 period, changes in the price of replacement power had a larger effect on real O&M costs when compared with the same effect estimated over the 1975-1992 period (Table 10). More important, on average over the 1975-1987 period the stringency of the PUC did not affect real O&M costs. Finally, on average, over the 1975-1987 period, the real O&M costs of plants located in States with an FAC were less than the costs of plants located in States without one.[74] This result suggested that, over the 1975-1987 period, the speed of recovery mattered. That is, utilities that could recovery their replacement power costs immediately by means of an FAC had less incentive to operate their plants efficiently and, therefore, had lower real O&M costs. Thus, over this time period, the time needed to recover the costs appeared to be a more important incentive than the certainty of cost recovery.

One possible explanation for these changes is related to the fall in replacement power costs (see Chapter 2). Regulatory lag is an incentive to minimize costs only when prices are increasing. Over the 1987-1992 period, when prices are falling, regulatory lag offers little incentive to minimize costs. Under such conditions, regulatory scrutiny would play a more important role. Thus, it was not surprising to find that regulatory scrutiny played a more important role after 1986.

Prices of the Other Factors Used To Produce Electricity

The other set of economic variables included in the analysis were the wage rates of individuals working at nuclear power plants, the prices of O&M materials, the price of fuel, and the price of capital additions. These variables capture the substitution possibilities between employees at nuclear power plants, O&M materials, capital additions, and fuel. For example, the effects of O&M employee wage rates on O&M costs depend on the sensitivity of the quantity of labor demanded to changes in labor wage rates, which in turn depend on the ease of substituting labor for fuel, capital, and so on. If the quantity of labor demanded were very sensitive to changes in wage rates (i.e., if demand were elastic), then increases in wages could lead to greater than proportionate decreases in employment and thus to lower nominal O&M costs.

The regression analysis found that increases in O&M worker wage rates had a very small, positive effect on nominal O&M costs. This effect was, however, not statistically significant. There are three possible explanations for this result. First, staffing levels could in fact be fairly sensitive to wage rates. Second, plant-specific wage rates exclusive of fringe benefits were used here. There are variations across utilities in the tradeoff between wages and fringe benefits. That is, some utilities have relatively high wages and low fringe benefits, while just the opposite is true for other utilities. However, such tradeoffs tend to be relatively constant over time. If there are random variations over time in the relative size of fringe benefits, the estimates of the labor cost effects presented here would be too low.

Third, as noted above, the method used to estimate the O&M cost model essentially transformed the data from levels to changes over time. There was substantial regional variation in the levels of the prices of O&M labor and materials, but the prices tended to increase at about the same rate. Thus, there was very little regional variation in the changes in these prices, as opposed to their levels. The lack of statistical significance could simply be due to lack of variation in the changes in prices.

Finally, as discussed in Appendix A, a number of variants of the basic model were estimated. There was a wide variation in the O&M worker wage rate elasticities derived from the different variants of the basic model, and the ones presented in Table 10 are at the upper end of the range of estimates. Again, this wide variation was probably due to the lack of regional variability in the changes in O&M labor and material prices.

The analysis also found that the price of capital and real O&M costs were negatively correlated. In this

[74]These changes are statistically different from zero. The F-statistic used to test the hypothesis that all these changes are different from zero is 2.87. One can therefore reject the null hypothesis that there are no changes in the relationship between real O&M costs and the economic and State regulatory incentives to improve performance.

analysis, the power plant (i.e., the containment, reactor vessel, the 40,000 or so pumps and valves, the 20 or so miles of pipes, the turbines, and so on) is viewed as the stock of capital. One would expect that decreases in the price of capital would cause an increase in the quantity of the capital service demanded. One way of increasing the quantity of capital services demanded is by improving plant performance. This can be accomplished by increasing maintenance expenditures.[75]

The price of fuel and real O&M costs are positively correlated. An increase in the price of fuel would cause a decrease in the quantity of fuel demanded. If fuel and capital are substitutes, the increase in the price of fuel would cause a decrease in the quantity of fuel demanded and an increase in demand for capital services. One way to increase the level of capital services is to improve maintenance by increasing real O&M costs.

In summary, the analysis suggests that utilities were trading O&M expenditures for fuel and capital costs. The absolute sizes of these tradeoffs appear to have gone down after the utilities began to initiate their cost control programs in the late 1980s. This is because the elasticities shown in Table 10 were greater when the model was estimated with data ending in 1987. However, these changes were not statistically significant.[76]

Analysis of Capital Additions Costs

The results of the regression analysis on capital additions costs are shown in Table 12. The same basic model was used. However, in the case of the capital additions analysis, the dependent variable was the natural logarithm of capital additions costs per kilowatt of capacity deflated by the GDP implicit price deflator. The reasons for this particular choice and alternative specifications are discussed in Appendix A.

The results of the analysis of capital additions costs are very different from those for the O&M costs. First, there was no measurable correlation between real capital additions costs and the economic factors discussed above. Some recent case studies found that roughly 50 percent of the capital additions costs were regulation-induced, and the bulk of the remaining 50 percent were simply repairs to plant components.[77] Since only a very small percent of the capital additions were done to improve performance, it is not surprising that these economic factors were not statistically significant.

The other two factors of importance—plant age and NRC regulations/industry learning—also influenced real capital additions costs. However, the directions of the effects were different when compared with the O&M cost analysis.

Plant Aging Effects

As noted above, the O&M cost analysis did not provide any evidence that O&M costs increased as plants aged. Additionally, the bulk of the statistical analyses of the performance of nuclear and coal-fired power plants suggested that performance also falls as plants age. Utilities have the choice of increasing maintenance to mitigate the effects of plant aging, in which case O&M costs should increase as plants age. If this maintenance was effective, performance should not deteriorate as plants age. Consequently, the results of the present analysis of O&M costs and other analyses of performance suggest that utilities did not increase O&M expenditures to mitigate the effects of plant aging, but instead let performance fall.

Capital additions costs and performance are negatively correlated. That is, plants with high levels of performance are seldom taken out of service to undertake repairs/replacements of plant components and therefore would have lower capital additions costs. Most of the empirical studies suggest that age and performance are negatively correlated. As expected, the analysis of capital additions costs (Table 12) suggests that capital additions costs increase as plants age. The finding of the present analysis of capital additions costs is, therefore, consistent with the results of the O&M cost analyses and the bulk of the studies of performance of nuclear and coal-fired power plants.

Additionally, the effects of plant aging on capital additions costs are not inconsequential. The results of the capital additions cost analysis using the time and

[75]Over time, the cost of replacement capacity was increasing. As long as electricity demand was increasing there would be an increased incentive to increase the longevity of the existing plants by increasing maintenance. Since short-run marginal replacement power costs were used, these data will not reflect increases in the cost of replacement capacity. Such influences therefore are probably being captured in regulatory effects.

[76]Again, the F-statistic used to test the null hypothesis that these changes were jointly equal to zero was 1.32. Thus, the null hypothesis cannot be rejected.

[77]See Sandy Cohen and Associates, *Analysis of the Role of Regulation in the Escalation of Nuclear Power Capital Additions Costs*, ORNL/SYB/88-SC557/1 (Oak Ridge, TN: Oak Ridge National Laboratory, July 1989).

industry learning specifications suggest that a 1-year increase in the age of the average plant caused an increase in real capital additions costs of $2 to $4 per kW.[78] Such increases are roughly 10 percent of the average capital additions costs computed over the entire 1975-1992 time period. In terms of elasticities, a small (1-percent) change in the age of the average plant caused costs increase of about 1.2 to 1.4 percent.

NRC Regulatory and Industry Learning Effects

The O&M cost analysis found that the effects of NRC regulations, industry learning, and any other unmeasurable factor correlated with time jointly caused real O&M costs to increase. However, these factors caused real capital additions costs to fall. The change in capital additions costs, after controlling for all other measurable factors other than regulation and industry learning, are shown in Figure 18.[79] Before 1981, the regulatory and learning (and other) effects tended to offset each other, causing real capital additions costs to remain roughly constant. After 1981, perhaps as the result of the completion of TMI-related retrofits, after controlling for all other factors, real capital additions costs fell.[80]

After controlling for age, after 1981, real capital additions cost fell. It was not surprising to find that increases in NRC regulatory actions and real capital additions costs were negatively correlated (Table 12, column 1). Because of the growth of the industry in the 1970s and 1980s, any measure of industry learning would be highly correlated with the growth in NRC regulatory activity. Consequently, the best that could be done was to measure the joint effect of both these factors. Since real capital additions costs and the number of NRC regulatory activities were negatively correlated, the learning (and other) effects tended to more than offset the regulatory effects.

Since the industry learning effects tended to be large, it was not surprising to find that industry experience and real capital additions costs were negatively correlated (Table 12, column 3). Other analyses found evidence of substantial learning-related reductions in the cost of major retrofit/repairs.[81] The results of this statistical analysis are, therefore, consistent with the observations of other industry analysts.

The results of the analysis just described assumed that the plant aging and industry experience effects are independent of each other. However, the industry focused much of its efforts on reducing the costs of aging-related repairs and retrofits. This observation suggests that the aging and learning effects may depend upon each other. Consequently, the basic capital additions model was changed so that the joint effects of aging and learning could be analyzed. This was done by replacing the experience variable with the product of age and industry experience. Additionally, there is evidence that the aging and learning effects may not be constant over time (Figure 8 in Chapter 2). Consequently, the model was also changed to allow for different joint effects of age and learning in the 1975-1986 and 1986-1992 periods, and for different aging effects for plants with ages less than and greater than 6 years.[82]

The results of this analysis are shown Table 13 and Figure 19. (Again, the relationships shown in Figure 19 were computed directly from the regression results reported in Table 13.) Three observations are warranted. First, it is interesting to note that aging effects are observed only for plants with ages greater than 6 years. Second, the regression analysis suggests that plant age and industry learning jointly caused real capital additions costs to fall after 1986 (Table 13). Third, as experience increases (Figure 19), the effect of plant aging (i.e., the slopes of the three lines) falls. In 1982, a 1-year increase in the age of an older plant (i.e., more than 6 years old) caused capital additions costs to increase by about $3 per kW. However, by 1992, the increase in capital additions costs caused by a 1-year increase in age fell to roughly $2 per kW, a reduction of about 33 percent. Thus, industry experience is, indeed, mitigating the effects of plant aging.

[78]Table 12 shows that the estimated aging effect depends on the particular measure of NRC regulatory activity. Since there does appear to be a substantial amount of learning, the specification that used industry learning is probably more reliable than the one that used the number of NRC regulations. Additionally, the relationship between any regulatory measure and costs will not be constant over time. This is because two effects that work in opposite directions are being measured. Thus, the one that uses time is probably the most reliable.

[79]Again, the data shown in Figure 18 were directly derived from the regression results shown in Table 12. They were computed in a manner similar to the one used to compute the estimates shown in Figure 14.

[80]There is collinearity between age and any of the regulatory variables. Consequently, the model was estimated after constraining the aging effect to a greater than zero. When this was done, the regulatory variable was always negative. As expected, the standard error fell substantially.

[81]See U.S. Congress, Office of Technology Assessment, *Aging Nuclear Power Plants: Managing Plant Life and Decommissioning*, OTA-E-575 (Washington, DC, 1993).

[82]Note that the dependent variable in this analysis was changed to costs in 1982 dollars per kilowatt of capacity.

Table 12. Results of the Capital Additions Cost Analysis

Variable	Coefficient		
	NRC Regulations[a]	Industry Learning[a]	Residual Escalation[a]
Plant Age	0.360374 (0.07142)*	0.247824 (0.04278)*	0.176339 (0.08943)*
Price of Replacement Power	0.587918 (0.57099)	0.474863 (0.56662)	0.52051 (0.57459)
Price of Replacement Power × Stringency of Public Utility Commission	0.045535 (0.13494)	0.041678 (0.13431)	0.064993 (0.13635)
O&M Worker Wage Rate	-0.01935 (0.0774)	0.011028 (0.07605)	-0.02717 (0.08429)
Price of O&M Materials	-0.02976 (0.01842)	-0.02348 (0.01837)	-0.00654 (0.02072)
Acquisition Price of Capital Good	0.047417 (0.08509)	0.094773 (0.08397)	0.018069 (0.09627)
Cost of Capital	-0.32099 (1.15797)	-0.03647 (1.14821)	-0.31265 (1.15495)
Price of Fuel	0.399877 (3.40665)	0.481846 (3.38682)	-1.1005 (3.3655)
NRC Regulatory Activity	-0.00343 (0.00074)*	NA --	NA --
Industry Learning	NA --	-0.00304 (0.00058)*	NA --
Cumulative NRC Fines to Year t-1	0.519819 (0.23443)*	0.481609 (0.22875)*	0.720689 (0.23203)*
Use of Incentive Rate of Return Program	0.369591 (0.17754)*	0.235771 (0.17819)	0.06137 (0.18294)
Experience at Other Plants Owned by the Same Utility	0.004695 (0.00505)	0.003469 (0.00499)	0.008879 (0.00499)
Natural Logarithm of Plant Size	0.813763 (0.44187)*	0.365923 (0.3678)	-0.00403 (0.49454)
Steam Generator Binary Variable	1.60996 (0.30407)*	1.62945 (0.30237)*	1.53191 (0.30432)*
Constant	NA --	NA --	-0.17092 (4.05498)

See notes at end of table.

Table 12. Results of the Capital Additions Cost Analysis (Continued)

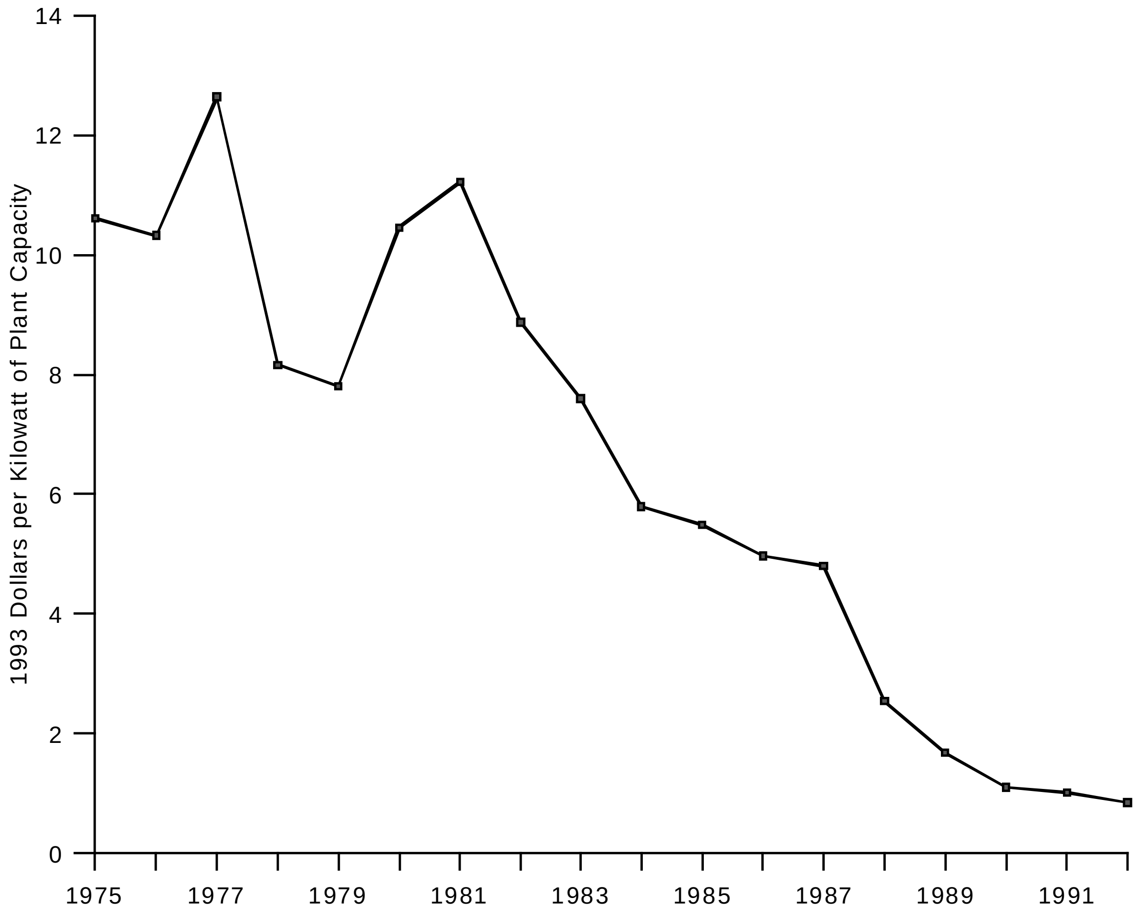
Variable	Coefficient		
	NRC Regulations	Industry Learning	Residual Escalation
Year of Observation:			
1975	NA --	NA --	2.53327 (1.57463)
1976	NA --	NA --	2.50568 (1.50111)
1977	NA --	NA --	2.70792 (1.39663)*
1979	NA --	NA --	2.27085 (1.3102)*
1980	NA --	NA --	2.22609 (1.22506)*
1981	NA --	NA --	2.51871 (1.12541)*
1982	NA --	NA --	2.58897 (1.04481)*
1983	NA --	NA --	2.35466 (0.95618)*
1984	NA --	NA --	2.20024 (0.85981)*
1985	NA --	NA --	1.92619 (0.76241)*
1986	NA --	NA --	1.87216 (0.68376)*
1987	NA --	NA --	1.77192 (0.59659)*
1988	NA --	NA --	1.73776 (0.51149)*
1989	NA --	NA --	1.10007 (0.42917)*
1990	NA --	NA --	0.683093 (0.35286)*
1991	NA --	NA --	0.173408 (0.23648)
Adjusted R-Squared	0.32	0.31	0.32

[a]These are the estimates from the model that used the particular measure of NRC regulatory activity and industry learning effects.

Notes: Standard errors are shown in parentheses. An asterisk (*) indicates that the coefficient is significant at a 0.95 level of confidence, using a one-tailed test. The dependent variable was the natural logarithm of capital additions costs in 1982 dollars per kilowatt of plant capacity.

Sources: Federal Energy Regulatory Commission, FERC Form 1, “Annual Report of Major Electric Utilities, Licensees and Others”; Energy Information Administration, Form EIA-412, “Annual Report of Public Electric Utilities,” and predecessor survey forms; and Utility Data Institute.

Figure 18. Residual Escalation in Capital Additions Costs, 1975-1992



Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute.

Table 13. Estimates of the Joint Effects of Plant Aging and Industry Learning

Variable	Coefficient	Standard Error
Plant Age 0 to 6 Years	-0.193154	1.31824
Plant Age Greater Than 6 Years	3.25636	1.07444*
Price of Replacement Power	8.08574	14.5646
Price of Replacement Power × Stringency of Public Utility Commission	2.54843	3.5345
O&M Worker Wage Rate	-1.7651	2.02477
Price of O&M Materials	0.019983	0.482128
Acquisition Price of Capital Good	0.967387	2.18953
Cost of Capital	-6.469	28.5838
Fuel Price	97.6812	95.3374
Industry Learning from 1975 to 1986 × Plant Age	-0.00061816	0.000922
Industry Learning from 1986 to 1992 × Plant Age	-0.00104809	0.000422*
Cumulative NRC Fines to Year t-1	14.7845	5.71446*
Use of Incentive Rate of Return	10.0379	4.48405*
Experience at Other Plants Owned by the Same Utility	0.034266	0.128524
Plant Size	-6.9481	9.13379
Steam Generator Binary Variable	71.5712	7.46788*
Constant	NA	--
Adjusted R-Squared	0.34	--

NA = not applicable.

Note: An asterisk (*) indicates that the coefficient is significant at the 0.95 level of confidence using a one-tailed test.

Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute.

4. Conclusions

This study found that capital additions costs peaked in 1984 and have fallen substantially since then. That is, real capital additions costs escalated from about $11 per kW of plant capacity to $62 per kW over the 1974-1984 period, then fell after 1986, to about $29 per kW in 1993. Additionally, the annual growth rate of real O&M costs fell substantially. Between 1974 and 1984, real O&M costs escalated at a rate of about 11 percent per year. However, over the 1985-1989 period, the annual growth rate fell to about 5 percent per year. Since then, real O&M costs have increased at an annual rate of less than 1 percent.

The objective of this analysis was to determine the factors causing the moderation in cost growth. To do this, the effects of the factors of importance (explained in detail in Chapter 3) on O&M and capital additions costs over the 1975-1987 and 1987-1992 periods were estimated. This was done by using the model to "predict" what costs would have been if all factors except the one under consideration had remained at their 1975 levels.[83] The results of this analysis are shown in Tables 14 and 15.

Over the 1975-1987 period, the average annual absolute increase in real O&M costs was about $5.10 per kW (Table 14). However, over the 1987-1992 period, the average annual increase fell by about 50 percent to about $2.40 per kW. Over the entire period, the joint effect of NRC regulation and industry learning was the most important factor influencing real O&M costs. Since this factor caused a larger increase in costs in the second than in the first period (1987-1992 vs. 1975-1987), it did not cause a reduction in the increase in real O&M costs.

Instead, the analysis found that changes in the economic and State regulatory incentives to improve performance were the most important set of factors mitigating O&M costs. Over the bulk of the 1975-1987 period, replacement power prices increased, causing real O&M costs to increase by about $3.10 per kW per year. However, over the 1987-1992 period, relative replacement power prices fell, and the reduction caused real O&M costs to fall by about $3.40 per year.[84] In short, changing incentives to improve plant performance—rather than regulatory considerations—caused the moderation in the growth of O&M costs.

As discussed in Chapter 3, real capital additions costs were influenced by plant aging and the combined effects of NRC regulatory activity and industry learning. Over the 1975-1992 period, these factors produced large changes in capital additions costs that tended to offset each other. Plant aging caused real capital additions costs to increase by about $4.10 per kW per year, while NRC regulatory activity and industry learning caused costs to fall by $2.60 per year.

Over the 1975-1987 period, NRC regulatory actions and industry learning jointly had a relatively small effect on real capital additions costs, and as a result of the aging effects, capital additions costs increased. Over the 1987-1992 period, however, NRC regulatory actions and industry learning jointly caused costs to fall by about $4.30 per kW per year. This decrease in costs more than offset the age-related cost increases of about $2.70 per kW per year, and as a result, real capital additions costs fell. Thus, very strong learning effects, which more than offset the aging effect, caused capital additions costs to fall.

[83]The procedure used to compute the predicted costs is explained in Appendix A. The mean values shown in this chapter and those presented in Chapter 2 are not the same, because the means computed in this chapter used the exact sample that was employed in the statistical analysis. Because of missing data for some of the explanatory variables, this sample was not the same as the one used for the analysis in Chapter 2. Additionally, the capital additions analysis used the natural logarithm of costs. Thus, 50 or so observations with negative capital additions costs were excluded. Finally, as explained in Appendix A, the procedures used to compute the means in this chapter and in Chapter 2 were different. The average O&M costs used in the two chapters are within 5 percent of each other. However, because of the exclusion of negative capital additions costs, the decrease in capital additions costs from 1987 to 1992 (shown in Table 15) was less than that reported in Chapter 2.

[84]Over the 1975-1992 period, the number of plants that were subject to FACs fell slightly, and the PUCs became slightly more stringent. However, the cost increases caused by these changes were minor.

Table 14. Factors Causing the Escalation in Real Operating and Maintenance Costs
(Annual Absolute Change in Real O&M Costs per Kilowatt of Plant Capacity, 1993 Dollars)

Factor	Time Period		
	1975-1987	1987-1992	1975-1992
Plant Age	-0.27	-0.69	-0.39
Price of Replacement Power	3.09	-3.43	1.07
NRC Regulatory Actions	7.48	8.72	7.83
NRC Enforcement	1.61	0.86	1.40
Prices Other Than O&M Labor and Materials	-2.48	-3.83	-3.05
O&M Labor and Materials	-1.10	-0.31	-0.88
Other and Unexplained	-3.28	1.08	-1.66
Total	**5.06**	**2.40**	**4.32**

Notes: The most important factor in the “Other and Unexplained” component was plant size, which increased by roughly 20 percent in the 1975 to 1987 period. Because an indirect measure of the NRC regulatory effect was used, this factor could also be capturing the effects of any relevant but unmeasurable factor highly correlated with time.

Sources: Federal Energy Regulatory Commission, FERC Form 1, “Annual Report of Major Electric Utilities, Licensees and Others”; Energy Information Administration, Form EIA-412, “Annual Report of Public Electric Utilities,” and predecessor survey forms; and Utility Data Institute.

Table 15. Factors Causing the Changes in Real Capital Additions Costs
(Annual Absolute Change in Real Capital Additions Costs per Kilowatt of Plant Capacity, 1993 Dollars)

Factor	Time Period		
	1975-1987	1987-1992	1975-1992
Plant Age	4.38	2.66	4.05
NRC Regulatory Actions and Industry Learning	-1.64	-4.26	-2.60
Other and Unexplained	-0.47	-1.17	-0.73
Total	**2.28**	**-2.77**	**0.72**

Note: Because an indirect measure of the NRC regulatory effect was used, this factor could also be capturing the effects of any relevant but unmeasurable factor highly correlated with time.

Sources: Federal Energy Regulatory Commission, FERC Form 1, “Annual Report of Major Electric Utilities, Licensees and Others”; Energy Information Administration, Form EIA-412, “Annual Report of Public Electric Utilities,” and predecessor survey forms; and Utility Data Institute.

There are still a number of unresolved questions that are crucial to any assessment and control of O&M and capital additions costs. First, this analysis was unable to disentangle the regulatory effects from those related to learning and other management-related factors. To do this, detailed case studies are needed. Such case studies would analyze the historical accounts of a plant’s costs, focusing on the causes of each cost increase. The information shown in Tables 14 and 15 highlights the importance of such case studies.

Second, part of the cost escalation was due to the desire to improve plant performance and safety. Over the 1983-1990 period, the average capacity factor of U.S. nuclear power plants increased from about 54 percent to 70 percent. Since 1990, the average capacity factor for U.S. nuclear power plants has remained constant. It would be useful to know how much of the increase in performance of U.S. nuclear power plants was due to increased maintenance expenditures, and whether the leveling off of nuclear power plant performance and O&M costs after 1990 are related. Such an analysis could yield insights into future trends in nuclear power plant performance.

Third, this analysis found that the factors affecting O&M and capital additions costs (plant aging, industry learning, and regulation) were changing over time. Thus, it would be useful to revisit the issue of the factors influencing nuclear operating costs in 4 or 5 years. Since the average plant will be about 20 years old by then, more insights about the aging effects could be gained.

Appendix A
Derivation of the Model and Econometric Issues

One objective of this appendix is to derive the model that was estimated in the body of the report. This is an economics-based cost-minimizing model that explicitly recognizes the tradeoffs between capacity utilization and maintenance costs. One of the basic questions that this update addresses is the reason for the moderation in growth in nuclear power plant operating costs. If, in fact, the moderation in costs represents a tradeoff between maintenance and plant performance, then it is not clear whether the reduction in O&M costs will result in lower total production costs. To examine this type of issue, an economic, as opposed to engineering, model is needed.

In most studies of production technologies, a fixed relationship between the stock of capital and the flow of capital services is assumed, in the sense that the flow of capital services can be changed only by altering the stock of capital. In this model, however, the firm can alter the capital services derived from a fixed stock of capital in response to changes in relative factor prices by changing its level of maintenance and, therefore, utilization.

Additionally, nuclear power plants are designed to be operated in "baseload" (i.e., they were designed to operate continuously). Thus, when a plant is out of service, replacement power must be obtained elsewhere. At least until the mid-1980s, increases in replacement power prices caused the cost of nuclear plant outages to increase substantially. Such increases in outage costs, therefore, represented an incentive to improve performance (i.e., capital utilization) by increasing maintenance expenditures. By estimating a model where capital utilization is endogenous, the role of such economic factors in causing the escalation in O&M costs can be examined.

The formal derivation of the model is as follows. Let K be the stock of capital and T the capital services derived from the capital stock. Thus, the utilization rate of the stock of capital would be $U = T/K$. The rate of depreciation of the capital stock, γ, is a function of the level of maintenance, M, and the level of utilization, U. Thus, $\gamma = \gamma(M,U)$, $\gamma_M < 0$, $\gamma_U > 0$, $\gamma_{MU} < 0$.

γ_U measures how the capital stock depreciates as it is utilized (i.e., the so-called "aging effects").[85] $\gamma_{MU} < 0$ implies that the aging effects can be mitigated by increased maintenance. R is the quantity of replacement power obtained elsewhere when the plant is out of service. Finally, N is the net investment in the plant, and Z is the vector of other inputs. (The most important other input is fuel.)

The utility will minimize the present value of the costs:

$$(1) \quad \int_0^{\infty} e^{-rt} [P_N N + P_M M + P_R R + P_Z Z] \quad .$$

P_N, P_M, P_R, and P_Z are the prices of investment goods, maintenance, replacement power, and the vector of other inputs, respectively.

The discounted costs [equation (1)] will be minimized subject to the following two constraints:

$$(2) \quad \dot{K} = N + \gamma(M,U)\,K$$

and

$$(3) \quad \bar{Q} = R + Y(T,Z) \quad .$$

The first constraint, equation (2), simply states that the change in the capital stock equals the amount of new investment plus the depreciation of the old stock.[86]

[85]Throughout this appendix, $\gamma_M = \dfrac{\partial\gamma}{\partial M}$, $\gamma_{MU} = \dfrac{\partial^2\gamma}{\partial M \partial U}$, and so on.

[86]Note that $\dot{K}$ is the change over time in K. It is also the quantity of capital additions. These capital additions consist of the replacement of fully depreciated plant components, γK, and plant improvements that increase performance and/or safety, N. Additionally, in the estimation of the model, operating labor input (i.e., the individuals that operate the plant) is ignored. In most plants there are no more than 40 to 50 plant operators, while the typical staffing level is about 1,000. Thus, the remaining 950 or so employees perform some type of maintenance (in a very broad sense of word) activities. Finally, this derivation follows M. Kim, "The Structure of Technology with Endogenous Capital Utilization," *International Economic Review*, Vol. 29 (1988), pp. 111-129; and L. Epstein and M. Denny, "Endogenous Capital Utilization in a Short-Run Production Model," *Journal of Econometrics*, Vol. 10 (1980), pp. 189-207.

The second constraint states that a fixed level of output, Q, must either be produced from the plant, Y, or obtained elsewhere, R. The production of electricity from the plant is

$$Y = Y(T,Z)$$

or

$$Y = Y(KU,Z) \quad .$$

Thus, the formal constrained minimization problem is to minimize equation (1), subject to equations (2) and (3):

$$\theta = \int_0^\infty e^{-rt}[P_N N + P_M M + P_R R + P_Z Z] + \lambda_0[\dot{K} - N - \gamma(M,U)K] + \lambda_1[\bar{Q} - R - Y(KU,Z)] \quad .$$

The resulting Euler-Lagrange first-order conditions are:[87]

(4a) $\theta_N = P_N e^{-rt} - \lambda_0 = 0$

(4b) $\theta_M = P_M e^{-rt} + \lambda_0 \gamma_M K = 0$

(4c) $\theta_R = P_R e^{-rt} - \lambda_1 = 0$

(4d) $\theta_Z = P_Z e^{-rt} - \lambda_1 Y_Z = 0$

(4e) $\theta_U = \lambda_0 \gamma_U K - \lambda_1 Y_T K = 0$

(4f) $\theta_K = \lambda_0 \gamma - \lambda_1 Y_T U - \frac{d}{dt}(\lambda_0) = 0$

(4g) $\theta_{\lambda_0} = \dot{K} - N + \gamma(M,U)K = 0$

(4h) $\theta_{\lambda_1} = \bar{Q} - R - Y(KU,Z) = 0 \quad .$

These first-order conditions have some interesting interpretations. First, equation (4c) states that the shadow price of the plant's output, λ_1, equals the discounted price of replacement power, P_R. The expression $\lambda_1 Y_T K$ in equation (4e) shows the benefits of increasing output, Y, achieved by increasing the effective utilization of the stock of capital, U, one unit.[88] Clearly, increases in P_R would increase the benefits of increasing the plant's output by increasing the capital stock utilization. The cost of increasing the plant's output by increasing the capital stock utilization is $\lambda_0 \gamma_U (MU) K$. (That is, increased utilization will lead to increased depreciation.) Equation (4e) states that the utilization of the capital stock will be set such that the costs and benefits will be equal at the margin.

Equation (4a) states that λ_0 equals the discounted price of the investment good, P_N. From equation (4b), the benefits of increased maintenance are the decreased depreciation of the capital stock, or $\lambda_0 \gamma_M K$. According to equation (4b), at the margin, these benefits will equal the discounted costs of improved maintenance, P_M.

Equations (4a) - (4h) are a set of eight equations in eight unknowns that can be solved for the optimal quantities of the maintenance and capital inputs—M^* and K^*, respectively—as a function of prices, the rate of interest, and $\bar{Q}$. That is:

(5a) $M^* = F(P_N, P_M, P_Z, P_R, \dot{P}_N, r, \bar{Q})$

(5b) $K^* = F(P_N, P_M, P_Z, P_R, \dot{P}_N, r, \bar{Q}) \quad .$

To explicitly represent safety regulation, the following constraint could be added:

$$\bar{S} - S(KU, Z) = 0 \quad .$$

This equation states that the "safety" output would be a function of the aged capital stock and the other input, Z. The constraint states that the utility must produce a minimum level of safety, $\bar{S}$, that would appear as an independent variable in equations (5a) and (5b). In effect, plant safety and plant output are treated as a joint good.

The comparative statistics with respect to equation (5b) are straightforward, and therefore the discussion will be limited to the maintenance input. Most importantly, the price of replacement power is effectively the shadow price of the plant's output. Thus, as was noted above, the greater the price of replacement power, the greater would be the benefits of improving utilization (plant output) by increasing maintenance, and an increase in P_R would cause an increase in the demand for the maintenance input.

Additionally, the greater the price of maintenance input, the less of it will be demanded. If the other input, Z, and capital are substitutes, an increase (decrease) in P_Z would increase (decrease) the demand for

[87] Again, $\theta_N = \frac{\partial \theta}{\partial N}$, and so on.

[88] Note that $\frac{\partial Y}{\partial U} = Y_T K$.

the capital services. Everything else being equal, capital services, T, can be increased by increasing the capital utilization rate by improving maintenance. Thus, if capital and Z are substitutes, an increase (decrease) in P_Z would cause an increase (decrease) in the demand for the maintenance input.

Finally, following Kim and Jorgensen, the user cost of the capital services, $P_N(\gamma^* + r) - \dot{P}_N$, can be derived from equations (4a)-(4h).[89] Increases in the user cost of capital services would cause a reduction in the quantity of the capital services demanded by reducing the level of maintenance. Thus, an increase in the user cost of the capital services would cause a decrease in the demand for the maintenance input. Since depreciation, γ^*, is endogenous, the three exogenous components of the user cost of the capital services will be included as exogenous variables. Increases in P_N and r and decreases in $\dot{P}_N$ would cause the user cost of the capital services to increase and the demand for maintenance input to fall.[90]

Thus, the expected signs associated with the exogenous variables of interest in equation (5a) are:

$$\frac{\partial M^*}{\partial P_R} > 0, \quad \frac{\partial M^*}{\partial P_M} < 0, \quad \frac{\partial M^*}{\partial P_N} < 0,$$

$$\frac{\partial M^*}{\partial r} < 0, \quad \frac{\partial M^*}{\partial \dot{P}_N} > 0, \quad \frac{\partial M^*}{\partial P_Z} > 0 \quad .$$

Equations (4a)-(4h) imply that the optimality conditions hold at every period t. Thus, the model as specified suggests that utilities can instantaneously adjust the optimal level of maintenance to changes in any of the exogenous variables shown in equation (5). At any point in time, however, the actual and optimal level of M^* may be different. After postulating a simple lagged adjustment mechanism, the following can be derived:

$$\text{(6a)} \quad M_t = F(P_N, P_M, P_Z, P_R, \dot{P}_N, r, \bar{Q}, \bar{S}, M_{t-1})$$

$$\text{(6b)} \quad K_t = F(P_N, P_M, P_Z, P_R, \dot{P}_N, r, \bar{Q}, \bar{S}, K_{t-1}) \quad .$$

A very simple stock adjustment process leads to a relatively simple distributed lag specification; more complex stock adjustment processes will result in more complex lag structures.

An alternative to this continuous time model is one that uses discrete time periods. Such a model was developed in the original 1988 study and was extended in a recent paper by Hewlett and McCabe.[91] In these models, plant output "today" is a function of maintenance in year t (i.e., "today") and in years t-1 and t-2. The result of the constrained minimization is input demand functions that contain input prices in year t and expected prices in years t+1 and t+2. That is, increased maintenance in year t will lead to improved performance in years t+1 and t+2. Thus, maintenance in year t will be a function of price in year t and expected prices in years t+1 and t+2. The original report shows that the model estimated in the body of this report is the same as a dynamic discrete time period model with myopic expectations. Additionally, Hewlett and McCabe presented some evidence to support the assumption of myopic expectations. Thus, the implicit assumption used in the present analysis is that utilities are myopic. Again, there is some evidence to support this assumption, and it does simplify the analysis considerably.

Specification of the Model

There are a number of issues dealing with the specification of equations (6a) and (6b) that were not discussed in the text. First, equation (6b) deals with the capital stock. The capital additions data are changes in the stock of capital or equation 6b in first difference form. Therefore, in the capital additions equation, all the prices and the rate of interest were expressed in first difference form. There are also some issues dealing with the functional form of equations (6a) and (6b). Since these issues are related to issues dealing with the multicollinearity between age and the NRC regulatory variables, they are discussed below.

[89]M. Kim, "The Structure of Technology with Endogenous Capital Utilization," *International Economic Review*, Vol. 29 (1988), pp. 111-129; and D. Jorgenson, "Capital Theory and Investment Behavior," *American Economic Review* (January 1963), pp. 247-259.

[90]The mathematical derivation of these comparative statistics is extremely difficult; since this is an empirical paper, they were not derived. However, numerical techniques were used to solve equations (4a) - (4h). Then, the exogenous variables of interest were increased by a very small amount, and the change in M was computed. The changes were consistent with this discussion.

[91]See Energy Information Administration, *An Analysis of Nuclear Power Plant Operating Costs*, DOE/EIA-0511 (Washington, DC, 1988), and James G. Hewlett and Mark J. McCabe, "Economic Regulation of Nuclear Power Plants," paper delivered at the 1995 meeting of the American Economic Association (Washington, DC, January 8, 1995).

Thus, the specifications of the O&M and capital additions cost equations are:[92]

$$(7a)\quad OM_{i,t} = a_o + a_1 P_{ml,i,t} + a_2 P_{mm,i,t} + a_3 P_{N,i,t} + a_4 r_{i,t}$$
$$+ a_5 P_{F,i,t} + a_6 P_{R,i,t} + a_7 P_{R,i,t} FAC_{i,t}$$
$$+ a_8 P_{R,i,t} REG_{i,t} + a_9 P_{R,i,t} REG_{i,t} FAC_{i,t}$$
$$+ a_{10} OEXSP_{i,t} + a_{11} IROR_{i,t} + a_{12} AGE_{i,t}$$
$$+ a_{13} CREG_t + a_{14} SIZE_{i,t}$$
$$+ a_{15}(P_{n,i,t} - P_{n,i,t-1}) + a_{16} OM_{i,t-1} + \varepsilon_{i,t}$$
$$+ \eta_i$$

$$(7b)\quad Ln(CAKW_{i,t}) = a_o + a_1 P_{ml,i,t} + a_2 P_{mm,i,t} + a_3 P_{N,i,t}$$
$$+ a_4 r_{i,t} + a_5 P_{F,i,t} + a_6 P_{R,i,t}$$
$$+ a_7 P_{R,i,t} REG_{i,t} + a_8 OEXSP_{i,t}$$
$$+ a_9 IROR_{i,t} + a_{10} AGE_{i,t}$$
$$+ a_{11} CREG_t + a_{12} \log(SIZE_{i,t})$$
$$+ a_{13}(P_{n,i,t} - P_{n,i,t-1}) + \varepsilon_{i,t} + \eta_i \quad .$$

where:

$OM_{i,t}$ = O&M expenditures for plant *i* in year *t*

$OM_{i,t-1}$ = O&M expenditures for plant *i* in year *t*-1

$Ln(CAKW_{i,t})$ = natural logarithm of real capital additions costs per kilowatt of capacity for plant *i* in year *t*

$P_{ml,i,t}$ = price of the O&M labor input as measured by the wage rate of onsite employees at plant *i* in year *t*

$P_{mm,i,t}$ = price of the O&M material input as measured by the cost of ready mix concrete in the area surrounding plant *i* in year *t*

$P_{N,i,t}$ = price of the capital input as measured by the wage rate of skilled construction workers in the area surrounding plant *i* in year *t*

$r_{i,t}$ = cost of capital as measured by the return on equity for the owner of plant *i* in year *t*

$P_{R,i,t}$ = price of replacement power for plant *i* in year *t*

$FAC_{i,t}$ = 1 if the owner of plant *i* in year *t* was subject to a fuel adjustment clause, and 0 otherwise

$REG_{i,t}$ = stringency of the State regulatory commission with jurisdiction over plant *i* in year *t*

$IROR_{i,t}$ = 1 if plant *i* was subject to an incentive rate of return program in year *t*

$OEXP_{i,t}$ = number of reactor operation years of other plants owned by the owner of plant *i* in year *t*

$AGE_{i,t}$ = age of plant *i* in year *t*

$CREG_t$ = cumulative NRC actions in year *t*

$SIZE_t$ = size of plant *i* in year *t*

$\varepsilon_{i,t}$, η_i = two random error terms for plant *i* in year *t*.

Note that the dependent variable in equation (7a) is O&M expenditures instead of the quantity of the O&M input. Roughly 75 percent of O&M expenditures are labor related, and the other 25 percent are for materials such as concrete for small construction projects, oil and lubricants, etc.[93] Thus, the best measure of the quantity of the O&M input would probably be staffing level measured in person-hours. Since such data are not available, expenditures were used as the dependent variable. Since O&M input prices are included as independent variables, the use of O&M expenditures should not present any problems.[94] Therefore, the estimates represent real changes (i.e., changes in quantities).

As discussed below, a proxy variable for the price of the capital good was used. Consequently, nominal capital additions expenditures were not used as the dependent variable. The alternative was to deflate the nominal expenditures. Unfortunately, there is no index

[92]Note that a static version of the capital additions cost equation was used. A version of the capital additions cost equation with a lagged dependent variable was estimated. As noted in the text, there are some distortions in the year-to-year changes in the capital additions costs, and as a result, the lagged capital additions cost coefficient was actually negative. Since this makes no economic sense, the lagged capital additions cost term was excluded. It should be noted that the inclusion of the lagged dependent variable did not affect the results of interest.

[93]H. Bowers, L. Fuller, and M. Myers, *Cost Estimating Relationships for Nuclear Plant Operation and Maintenance*, ORNL/TM-10564 (Oak Ridge, TN: Oak Ridge National Laboratory, 1988).

[94]Initially, an attempt was made to estimate factor share equations using a translog specification. This specification produced poor results. To compute factor shares, the cost of replacement power had to be computed. As noted below, the computation of the price of replacement power was difficult. The quantity of replacement power was even more difficult to compute. The use of the product of the price and quantity of replacement power introduced massive measurement error and probably explains the poor results.

of capital additions prices; therefore, by default, nominal capital additions deflated with the GDP Implicit Price Deflator were used as the measure of the quantity of the capital additions input.

There are, however, problems with the use of both the O&M labor wage rates and the GDP Implicit Price Index as deflators. First, as was noted in the text, the O&M labor wage rate variable does not include any overtime or fringe benefits. More importantly, the GDP deflator measures the changes in all prices and is not regional. Therefore, two other deflators were used. Those results are presented later in this appendix.

Estimation

Equations (7a) and (7b) were estimated using the so-called "fixed effects" model. These estimates were essentially derived by using ordinary least squares to estimate a version of the model that included a series of 69 plant-specific dummy variables.[95] Thus, fixed effects estimates allow for the intercept to vary across plants. These estimates are consistent, and if the two error terms in equations (7a) and (7b) are uncorrelated with any of the independent variables, efficient estimates can be derived by using Generalized Least Squares (GLS).

Ordinary Least Squares (OLS), Fixed Effects, and GLS estimates of equations (7a) and (7b) are shown in Tables A1 and A2, respectively.[96] As these two tables show, there are differences between the fixed effects and GLS estimates. Not surprisingly, the Hausman specification error test suggests that the cross-sectional error term is correlated with at least one of the explanatory variables, therefore causing the GLS estimates to be biased and inconsistent. Thus, the focus will be on the fixed effects estimates.

It must also be noted that the inclusion of a lagged dependent variable in the O&M cost equation will cause the fixed effects estimates of the lagged O&M cost coefficient to be biased downward and the OLS estimates to be biased upward if the number of time series observations is relatively small. In the present analysis, there are roughly 15 time series observations per plant. According to Hsiao, for such a sample, the bias will be slightly less than 0.1, and, therefore, the bias will be relatively small.[97] All of these observations are consistent with the estimates shown in Table A1. That is, the OLS estimate of the lagged O&M cost coefficient is greater than the fixed effects estimates. However, since the bias is rather small, the differences are not that great.[98]

Additionally, there is some evidence of cross-sectional heteroskedasticity. Fixed effects estimates can be derived by including dummy variables for each cross-sectional observation in the sample. To correct for the heteroskedasticity, each observation was weighted by the inverse of plant size. The standard errors increased by less than 5 percent.

The GLS and fixed effects results shown here were derived using the PANEL procedure in the econometric software package, *Time Series Processor* (TSP). This procedure automatically computes the fixed effects and GLS estimates. Unfortunately, although the PANEL procedure in TSP is easy to use and is computationally very efficient, weighted regressions cannot be estimated. Since the biases resulting from heteroskedasticity appear to be small, for computational reasons no correction for heteroskedasticity was made here.

To test for autocorrelated residuals over time, an average first order autocorrelation coefficient—i.e., rho—was computed. In the capital additions equation, rho was extremely small, suggesting that first order autocorrelation was not present. Since the O&M equation has a lagged dependent variable, both rho and the Durbin-Watson statistic will be biased. Thus, an average Durbin H-statistic was also computed (Table A1). These Durbin H-statistics suggest that first-order autocorrelation was again not present in the O&M equation.[99]

The fixed effects estimates allow the intercepts to vary across the cross-sectional observations. There is also every reason to believe that some of the coefficients

[95]Issues dealing with the correlation in the error terms over time (i.e., intertemporal autocorrelation) and across plants (cross-sectional heteroskedasticity) are discussed below.

[96]The GLS estimates are sometimes called "random effects" estimates. To derive these estimates, the variances of the cross-sectional and time-series errors terms are computed. These estimates are then used to derive the GLS estimates. Finally, the Hausman specification error test is used to determine whether the fixed effects and GLS estimates are equal. If they are not, there is an omitted cross-sectional variable that will bias the GLS estimates. For a complete description of these points, see H. Cheng, *Analysis of Panel Data* (New York, NY: Cambridge University Press, 1987).

[97]See H. Cheng, *Analysis of Panel Data* (New York, NY: Cambridge University Press, 1987), p. 74.

[98]There some instrumental variable techniques that can be used to derive consistent estimates of fixed effects models with lagged dependent variables. In the present analysis an attempt was made to use these techniques. The results, however, were very poor.

[99]See Appendix A in the original report for a discussion of how the average first order autocorrelation statistic was computed.

Table A1. OLS, GLS, and Fixed Effects Estimates of the Operating and Maintenance Cost Model

Variable	Coefficient		
	OLS	Fixed Effects	GLS
Plant Age	-223.729 (146.746)	-285.114 (1,492.22)	-72.8152 (205.359)
Price of Replacement Power	6,669.6 (6,409.06)	2,922.1 (8,936.16)	4,227.02 (7,399.45)
Price of Replacement Power × Stringency of Public Utility Commission	2,539.63 (1,876.8)*	4,560.91 (2,735.76)*	4,346.35 (2,187.37)*
Price of Replacement Power × Use of Fuel Adjustment Clause Dummy	-2,928.63 (6,654.38)	-4,221.28 (8,651.46)	-3,637.18 (7,492.69)
Price of Replacement Power × Use of Fuel Adjustment Clause Dummy × Stringency of PUC	-334.29 (2,245.77)	760.371 (3,264.25)	-331.616 (2,637.8)
O&M Worker Wage Rate	1,379.75 (733.657)	348.649 (1,003.87)	1,367.28 (821.34)
Price of O&M Materials	-83.0138 (123.259)	-115.481 (220.688)	-92.5336 (147.297)
Fuel Price	100,936 (36,074.1)*	124,504 (44,339.7)*	94,338 (37,835.2)*
Acquisition Price of Capital Good	-586.116 (438.483)	-1,636.99 (570.754)*	-944.209 (478.502)*
Cost of Capital	-30,118.1 (37,812)	23,571.4 (39,552.7)	-11,506 (36,956)
Change in Acquisition Price of Capital Good	1,320.32 (1,321.85)	2,496.52 (1,283.67)*	1,823.4 (1,242.8)
NRC Regulatory Activity or Industry Learning	12.6483 (4.50473)*	39.6544 (13.6862)*	19.9341 (5.22144)*
Average NRC Fines to Year t-1	39.0177 (18.0861)*	129.069 (24.649)*	60.6868 (19.8877)*
Incentive Rate of Return Binary Variable	4,999.46 (1,763.95)*	5,091.22 (2,694.28)*	6,259.04 (2,156.59)*
Plant Size	13.9188 (1.30079)*	16.7881 (4.47107)*	17.1128 (1.73588)*
Experience at Other Plants Owned by the Same Utility	-89.4729 (64.5383)	256.99 (144.898)	-71.0138 (84.6276)
Retrofit Binary Variable	3,155.08 (3,458.13)	8,650.86 (3,472.93)*	5,326.29 (3,339.37)
O&M Costs in Year t-1	0.715061 (0.02362)*	0.464712 (0.02864)*	0.611025 (0.0246)*
Constant	-14,718.7 (7,038.86)*	NA --	-17,833.6 (7,381.45)
R-Squared	0.90	0.84	0.88
Durbin H-Statistic	NA	-0.04	NA
Hausman M-Statistic	NA	115.4	NA

Note: Standard errors are shown in parentheses. An asterisk (*) indicates that the coefficient is significant at the 0.95 level of confidence using a one-tailed test.

Table A2. OLS, GLS, and Fixed Effects Estimates of the Capital Additions Cost Model

Variable	Coefficient		
	OLS	Fixed Effects	GLS
Plant Age	0.004573 (0.01587)	0.360374* (0.07142)	0.037103 (0.02421)
Price of Replacement Power	0.312385 (0.60008)	0.587918 (0.57099)	0.329172 (0.56212)
Price of Replacement Power × Stringency of Public Utility Commission	0.03519 (0.14138)	0.045535 (0.13494)	0.029329 (0.1331)
O&M Worker Wage Rate	0.038054 (0.08098)	-0.01935 (0.0774)	0.03766 (0.07569)
Price of O&M Materials	-0.04578 (0.0195)	-0.02976 (0.01842)	-0.03862 (0.01823)*
Acquisition Price of Capital Good	0.119392 (0.08265)	0.047417 (0.08509)	0.101013 (0.08112)
Cost of Capital	0.095135 (1.21227)	-0.32099 (1.15797)	0.191548 (1.14314)
Fuel Price	3.26084 (3.52683)	0.399877 (3.40665)	2.11167 (3.32322)
NRC Regulatory Activity	0.000045 (0.00018)	-0.00343 (0.00074)*	-0.00017 (0.00025)
Cumulative NRC Fines to Year t-1	0.55644 (0.17472)*	0.519819 (0.23443)*	0.355519 (0.19879)
Use of Incentive Rate of Return	0.443615 (0.10846)*	0.369591 (0.17754)*	0.422314 (0.13484)*
Experience at Other Plants Owned by the Same Utility	-0.00084 (0.00217)	0.004695 (0.00505)	0.00104 (0.00284)
Plant Size	-0.51298 (0.10266)*	0.813763 (0.44187)	-0.4936 (0.16368)*
New Plant Binary Variable	0.222257 (0.342)	NA --	0.32101 (0.341)
Steam Generator Binary Variable	1.62802 (0.31483)*	1.60996 (0.30407)*	1.66167 (0.29968)*
Constant	5.86561 (0.75035)*	NA --	5.62405 (1.17591)*
Adjusted R-Squared	0.14	0.26	0.05
First-Order Autocorrelation Coefficient	NA	0.03	NA
Hausman M-Statistic	NA	38.8	NA

Note: Standard errors are shown in parentheses. An asterisk (*) indicates that the coefficient is significant at the 0.95 level of confidence using a one-tailed test.

might not be constant across plants, suggesting that some type of random coefficient model would be appropriate.[100] Any of these random coefficient models essentially requires separate estimates of the model for each plant. Unfortunately, with only 15 or so time series observations, there will be more independent variables than observations, resulting in negative degrees of freedom. Thus, at this point, the estimation of a random coefficients model is apparently not possible. Instead, to determine the sensitivity of the results to the restrictions of equal coefficients across plants, the age, NRC regulatory activity, fuel price, and capital price coefficients were individually allowed to vary across plants while holding all others constant. This exercise did suggest that many of the coefficients varied across plants—a point that should not be over-

[100]The most obvious coefficient that might vary across plants is age. As any car owner knows, there is random variation in the aging of cars with the same make and model.

looked when forecasting plant-specific costs. In the aggregate, however, the results of interest did not change noticeably when each of the other coefficients was allowed to vary.

Multicollinearity and the Functional Forms of the NRC Regulatory and Plant Aging Variables

Obviously, there is a substantial amount of collinearity between plant age and NRC regulatory activity, because both were increasing over time. Multicollinearity will result in relatively large standard errors, and as a result, the coefficients of two collinear variables will often be statistically insignificant. However, this was not the case in the analysis presented in the body of this report. In this respect, multicollinearity was not a problem.

A linear functional form was used in the O&M cost analysis presented in the text. If, in fact, either the aging or the regulatory effects were nonlinear, the bias caused by the misspecification of one effect could be captured by the other collinear variable. That is, because of the multicollinearity between age and the NRC regulatory variable, the misspecification of the functional form of one variable could cause serious biases in the other one. Additionally, the elasticities computed from a linear model will depend upon the ratios of the independent and dependent variables. Thus, in a linear model the elasticities could either be very large or very small, depending on the relative values of the independent and dependent variables. Third, when expenditures are used in an input demand equation, the natural logarithm of expenditures is typically used as the dependent variable. It is important, therefore, to estimate some nonlinear O&M cost models.

Two basic types of nonlinear specifications were examined. The first general type was multiplicative/ exponential models. A multiplicative model can be estimated easily by taking the natural logarithms of the independent and dependent variables. Exponential models can be derived by simply taking the natural logarithm of the dependent variable. These two are typically called the log-log and log-linear specifications, respectively. In the log-log specification, the elasticities are independent of the values of the independent or dependent variables. In the log-linear specification, the elasticity will depend only on the value of independent variable.

The second general type of nonlinear specification was derived by using piecewise linear variables.[101] These specifications, which allow the slopes to change over different intervals of the independent variable, are much less restrictive than log-log or log-linear models that impose *a priori* restrictions on the functional form of the variable in question.

Estimates of the linear and log-linear specifications of the O&M cost model are shown in Table A3.[102] Estimates of the O&M cost model with piecewise linear (and log-linear) age and regulatory variables are also presented in this table. Table A4 presents estimates of the model with two log-log specifications. Various elasticities are shown in Table A5.

The first noteworthy result of this analysis was that the replacement power price elasticity does not vary substantially across specifications (Table A5). This elasticity varies from 0.1 to 0.2, depending on the specification used.

The disentanglement of the aging and NRC regulatory effects was somewhat sensitive to the functional form of the O&M model. The log-log specification produced results that are roughly consistent with those presented in the body of this report. The estimated aging elasticity was somewhat larger that the one presented in the body (i.e., -0.14 as opposed to -0.08) and was statistically significant. Additionally, the elasticities associated with the NRC regulatory action variable derived from the linear and log-log specifications were very similar (Table A5).

The log-linear specification did result in a very large and positive plant aging effect and a statistically insignificant regulatory effect (Table A3, specification D). This, however, was due to the restrictive assumption that the regulatory effects were increasing exponentially over time. The pattern of the yearly dummy variables shown in Table 9 in the body of this report suggested that after 1980 the regulatory effect was

[101]See, for example, Victor McGee and Willard Carlton, "Piece-wise Regressions," *Journal of the American Statistical Association*, Vol. 65 (September 1970), pp. 1109-1124.

[102]Because panel data were used, the construction of databases used by the software employed in this analysis, TSP, was time-consuming. The 1992 and 1993 data were collected toward the end of this project. Consequently, much of the preliminary statistical analysis, including the sensitivity analyses described in this section of the appendix, was done using data ending in 1991. For comparison, estimates of the linear model with data through 1991 were included.

Table A3. Nonlinear Estimates of the Operating and Maintenance Cost Model

Variable	Specification[a] A	B	C	D	E
Plant Age	-554.605 (1,513.14)	NA --	646.8032 (1,769.44)	0.088894 (0.02246)*	0.028821 (0.02386)
Plant Age: 0 to 5 Years	NA --	-829.247 (1,245.77)	NA --	NA --	NA --
Plant Age: 6 to 10 Years	NA --	-71.3305 (99.848)	NA --	NA --	NA --
Plant Age: 11 to 15 Years	NA --	1,624.563 (1,451.64)	NA --	NA --	NA --
Plant Age: 16 to 20 Years	NA --	522.1309 (2,238.3)	NA --	NA --	NA --
Plant Age: 21 Years or More	NA --	1,383.131 (3,768.58)	NA --	NA --	NA --
Price of Replacement Power	5,421.47 (8,679.65)	4,350.907 (8,731.67)	3,687.338 (8,743.65)	0.366905 (0.12475)*	0.222863 (0.11746)*
Price of Replacement Power × Stringency of Public Utility Commission	4,854.34 (2,624.39)*	4,728.758 (2,632.38)*	5,373.19 (2,649.78)*	0.067851 (0.03761)*	0.065296 (0.03543)*
Price of Replacement Power × Use of Fuel Adjustment Clause	-6,576.62 (8,360.18)	-6,462.36 (8,433.02)	-6,298.41 (8,464.35)	-0.00581 (0.1204)	-0.10474 (0.11377)*
Price of Replacement Power × Use of Fuel Adjustment Clause × Stringency of Public Utility Commission	1,763.601 (3,195.24)	1,697.883 (3,205.04)	2,055.662 (3,242.08)	-0.0192 (0.04601)	0.019073 (0.04358)*
O&M Worker Wage Rate	-17.9185 (1,013.77)	4.702629 (1,015.55)	-382.806 (1,075.86)	0.022434 (0.01456)*	-0.02918 (0.01453)*
Price of O&M Materials	-85.1494 (218.308)	-58.2982 (212.68)	75.88964 (266.679)	0.009321 (0.00316)*	-0.005 (0.00358)
Fuel Price	182,469 (45,088.1)*	181,338.6 (46,520.5)*	169,407.5 (47,908.8)*	2.453263 (0.64737)*	0.743892 (0.62913)
Acquisition Price of Capital Good	-1,650.08 (600.977)*	-1,530.52 (611.164)*	-2,060.39 (642.596)*	-0.0142 (0.0086)*	-0.03087 (0.00864)*
Change in Acquisition Price of Capital Good	2,615.617 (1,231.16)*	2,720.669 (1,233.73)*	3,127.408 (1,270.05)*	0.010154 (0.0177)	0.04195 (0.01708)*
Interest Rate	26,285.02 (38,301.1)	9,737.738 (40,052.4)	-10,526.8 (46,966.8)	1.799962 (0.55831)*	-1.11428 (0.62782)*
Cumulative Number of NRC Actions	42.43193 (13.6549)*	44.446 (13.2467)*	NA --	-0.00015 (0.0002)*	NA --
Cumulative Number of NRC Actions: 0 to 300	NA --	NA --	-1.40554 (34.8684)	NA --	0.002388 (0.00046)*
Cumulative Number of NRC Actions: 301 to 700	NA --	NA --	47.39689 (22.7767)*	NA --	0.002212 (0.00031)*
Cumulative Number of NRC Actions: 701 to 1,100	NA --	NA --	35.79245 (16.3804)*	NA --	0.00075 (0.00022)*
Cumulative Number of NRC Actions: 1,101 or More	NA --	NA --	31.01448 (16.9001)*	NA --	0.000569 (0.00023)*
Average NRC Fines to Year t-1	132.2773 (24.442)*	128.1646 (25.107)*	131.6564 (24.5814)*	0.000705 (0.00034)*	0.001013 (0.00032)*
Plant Size	15.13734 (4.68633)*	14.9602 (4.73145)*	17.47171 (5.20665)*	0.000461 (0.00007)*	0.00035 (0.00007)*
Incentive Rate of Return Binary Variable	5,503.742 (2,573.19)*	5,324.143 (2,570.28)*	5,370.145 (2,580.57)*	0.181208 (0.03707)*	0.153379 (0.0347)*
Experience at Other Plants Owned by the Same Utility	177.9969 (169.27)	188.9335 (169.657)	215.4931 (170.552)	-0.00474 (0.00243)*	-0.00283 (0.00229)

See notes at end of table.

Table A3. Nonlinear Estimates of the Operating and Maintenance Cost Model (Continued)

Variable	Specification[a] A	B	C	D	E
Retrofit Binary Variable	14,049.22 (3,429.92)*	14,045.78 (3,432.91)*	14,278.09 (3,435.26)*	-0.00062 (0.04873)	0.053206 (0.04577)
O&M Costs in Year t-1	0.464112 (0.02908)*	0.469342 (0.03065)*	0.46061 (0.03017)*	0.241032 (0.02506)*	0.18325 (0.02411)*
Constant	NA --	NA --	NA --	NA --	NA --
R-Squared	0.85	0.85	0.85	0.91	0.92

[a]Specifications: A = linear; B = linear with piecewise linear age variables; C = linear with piecewise linear NRC regulatory variables; D = log-linear; E = log-linear with piecewise linear NRC regulatory variables.

Note: Standard errors are shown in parentheses. An asterisk (*) indicates that the coefficient is significant at the 0.95 level of confidence using a one-tailed test. In the log-linear specifications, the dependent variable was the natural logarithm of O&M costs.

constant over time. A similar result was obtained when the yearly dummy variables were included in the log-log and log-linear specifications (Figure A1). Moreover, the use of piecewise linear and log-linear regulatory variables also suggested that, after 1979, real O&M costs were increasing at a roughly constant absolute rate (Table A3, specifications C and E, and Figure A2). That is, the last three piecewise regulatory variables suggest that after the 300th regulatory action, which occurred in 1979, the relationship between NRC regulatory activity and O&M costs was roughly linear.[103]

In short, all the specifications that imposed relatively few *a priori* restrictions on the functional form of the regulatory variables (i.e., the piecewise linear and yearly dummy variables) suggest that, after 1979, the NRC regulatory effects were roughly constant over time. It would, therefore, appear that the large and positive aging effect derived from the log-linear model was simply due to the very restrictive *a priori* assumption that costs induced by regulatory activity were increasing exponentially over time. In fact, when the piecewise linear NRC variables were included in the log-linear specification, large and positive regulatory effects were obtained (Table A3, specification E, and Figure A2.) Moreover, the aging coefficient in this specification was not statistically significant.[104]

As noted in the text, the levels of the O&M and capital input prices vary substantially from one region to another. However, there was substantially less variation in the changes in these input prices. That is, both input prices tended to change at roughly the same absolute rate. Thus, it was not surprising to find that the estimated elasticities for the labor and capital inputs were sensitive to the assumed functional form of the model.

Comparison With Results in the 1991 Update

The results of the aging analysis in the present update were different from those in the previous reports. With respect to O&M costs, the original study and the 1991 update found evidence of substantial negative aging effects, whereas the present update did not find any evidence of any measurable aging effect. Additionally, the original study and the first update found that aging caused capital additions costs to increase only in boiling-water reactors and reactors that used salt water as a source of cooling. However, the present analysis found aging effects for all power plants.

There are a number of differences between the original study (and the 1991 update) and the present report. The most important ones are as follows:

1. The current model is more fully specified to capture substitution between the O&M and capital additions inputs and fuel.
2. Different measures of the NRC regulatory effects are used.

[103]The last three piecewise linear regulatory coefficients shown in Table A3, specification C, suggest that the effects fell slightly over time. This was because the NRC regulatory coefficients were falling. However, the reductions were not statistically significant.

[104]Since the measure of NRC regulatory activity was increasing at a roughly constant absolute rate over time, this variable is roughly equivalent to a time trend. When the regulatory variable was replaced with time raised to the *e* power, positive regulatory and statistically insignificant aging effects were observed. Thus, the log-linear results seem to be odd.

Table A4. Log-Log Estimates of the Operating and Maintenance Cost Model

Variable	Specification[a] A	Specification[a] B
Plant Age	-0.14397 (0.0456)*	NA --
Plant Age: 0 to 5 Years	NA --	-0.05984 (0.05295)
Plant Age: 6 to 10 Years	NA --	0.149271 (0.09542)
Plant Age: 11 to 15 Years	NA --	0.602595 (0.14262)*
Plant Age: 16 to 20 Years	NA --	0.563675 (0.22537)*
Plant Age: 21 Years or More	NA --	0.177286 0.667996
Price of Replacement Power	0.078194 (0.04306)*	0.143146 (0.044)*
Price of Replacement Power × Stringency of Public Utility Commission	-0.00346 (0.02289)	-0.02708 (0.02295)
Price of Replacement Power × Use of Fuel Adjustment Clause	0.01808 (0.02769)	0.004169 (0.0273)
Price of Replacement Power × Use of Fuel Adjustment Clause × Stringency of Public Utility Commission	-0.02829 (0.02405)	-0.00623 (0.02403)
O&M Worker Wage Rate	0.4 (0.1821)*	-0.00662 (0.1959)
Price of O&M Materials	-0.44508 (0.1504)*	-0.08021 (0.163)
Fuel Price	0.030258 (0.03016)	0.076561 (0.03108)*
Acquisition Price of Capital Good	0.052249 (0.14297)	-0.00589 (0.14173)
Change in Acquisition Price of Capital Good	NA --	NA --
Interest Rate	0.083437 (0.05797)	0.137728 (0.06133)*
Cumulative Number of NRC Actions	0.561243 (0.07665)*	0.381194 (0.08356)*
Average NRC Fines to Year t-1	0.014843 (0.0045)*	0.012051 (0.00447)*
Plant Size	0.397581 (0.0682)*	0.601009 (0.07641)*
Incentive Rate of Return Binary Variable	0.123151 (0.03565)*	0.128531 (0.03499)*
Experience at Other Plants Owned by the Same Utility	-0.00557 (0.00666)	-0.00897 (0.00659)
Retrofit Binary Variable	0.071309 (0.04609)	0.051254 (0.04541)
O&M Costs in Year t-1	0.246554 (0.02585)*	0.232209 (0.02655)*

See notes at end of table.

Table A4. Log-Log Estimates of the Operating and Maintenance Cost Model (Continued)

Variable	Specification[a]	
	A	B
Constant	NA --	NA --
R-Squared	0.91	0.92

[a]Specifications: A = log-log; B = log-log with piecewise linear age variables.

Note: Standard errors are shown in parentheses. An asterisk (*) indicates that the coefficient is significant at the 0.95 level of confidence using a one-tailed test. In the log-log specifications, the dependent variable was the natural logarithm of O&M costs, and all the independent variables except the binary variables were expressed in logarithmic form.

Table A5. Estimated Elasticities From Various Specifications of the Operating and Maintenance Cost Model

Variable	Specification			
	Linear	Log-Linear	Log-Log	Deflated Costs
NRC Regulatory Actions	0.54	-0.12	0.56	0.26
NRC Enforcement Actions	0.04	0.01	0.01	0.03
Price of Replacement Power	0.09	0.17	0.08	0.11
Stringency of Public Service Commission	0.09	0.05	0.02	0.07
Use of Fuel Adjustment Clause	0.01	-0.01	0.06	-0.01
Plant Age	-0.08	0.79	-0.14	0.18
Price of O&M Labor	-1.00	-0.70	-0.60	-0.09
Price of O&M Materials	-1.06	-0.60	-1.45	0.04
Price of Capital Good	-0.41	-0.21	0.05	-0.54
Fuel Price	0.15	0.12	0.03	0.13

Note: In the log-linear and log-log specifications, the dependent variable was the natural logarithm of O&M costs. In the log-log specification, natural logarithms of the independent variables were also used. Additionally, in the linear and log-linear specifications, the elasticities were computed at the means of the appropriate variables.

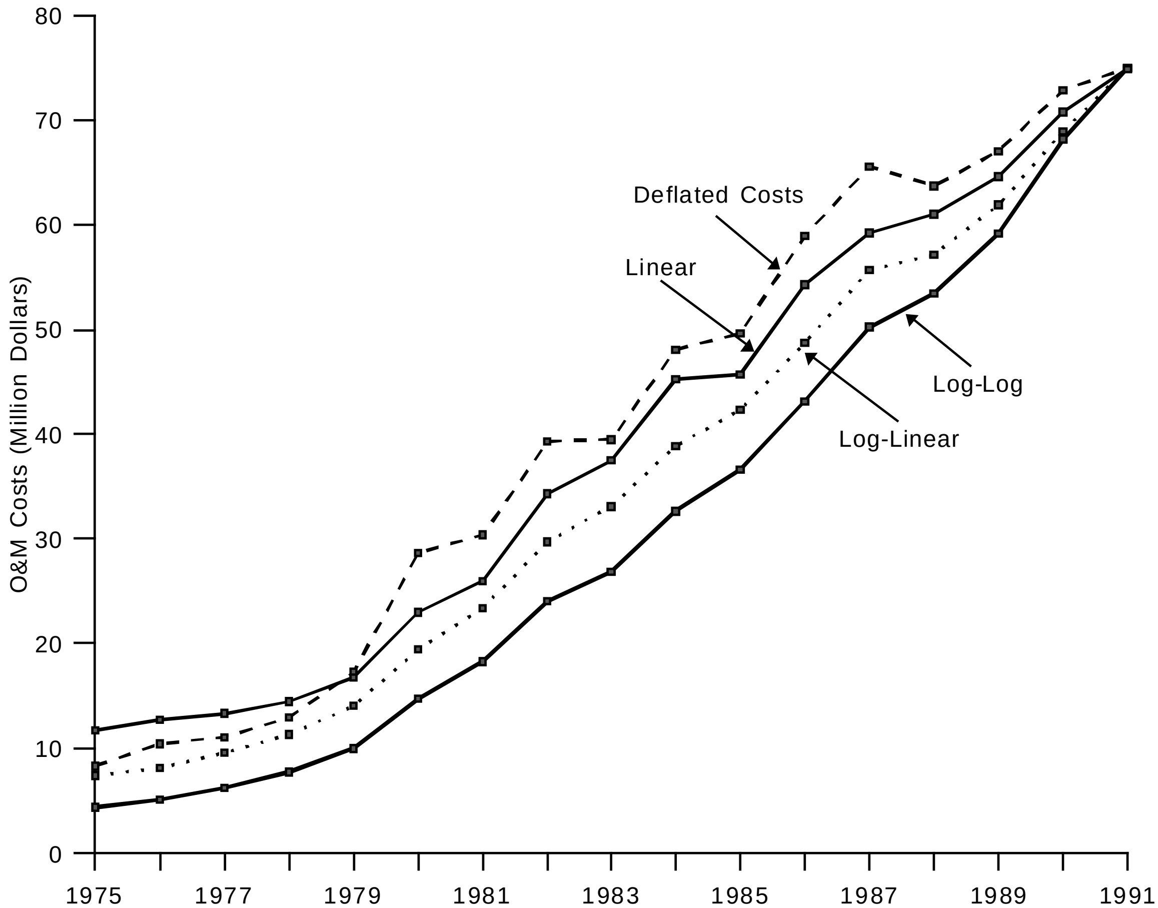
3. A different measure of the cost of the capital input is used.
4. A different measure of the price of the O&M materials input is employed.
5. A simpler lag structure is used.
6. The sample size is about 30 percent greater than that used for the 1991 update and 50 percent greater than the sample used in the original study.

To determine which of these changes caused different aging effects with respect to O&M costs to be observed, the model was reestimated using all the old data and the old specification (i.e., the ones used in the original study). Then, the model and/or data were changed to reflect all the changes discussed above. The exercise indicated that the two most important changes were the larger sample size and the use of regional prices for the O&M materials input.

These points are shown in Table A6, which shows the results of the O&M cost analysis using different model specifications, different measures of the price of the O&M materials input, and different sample sizes. The first column in the table shows the results of the analysis using the old model and data estimated from 1975 to 1984.[105] This essentially replicated the original study. The information in the first column shows

[105]The data in the original study began in 1975 and ended in 1984. The 1991 update used data from 1974 to 1987. The capital price data were not available before 1974. Because one of the independent variables is the change in the price of the capital good, the present update could not use 1974 data. Thus, in this section all the comparisons will be with the original study, since the beginning year in each was 1975.

Figure A1. Residual Escalation in Real Operating and Maintenance Costs



Note: This graph shows the residual escalation in O&M costs derived from four specifications of the model.

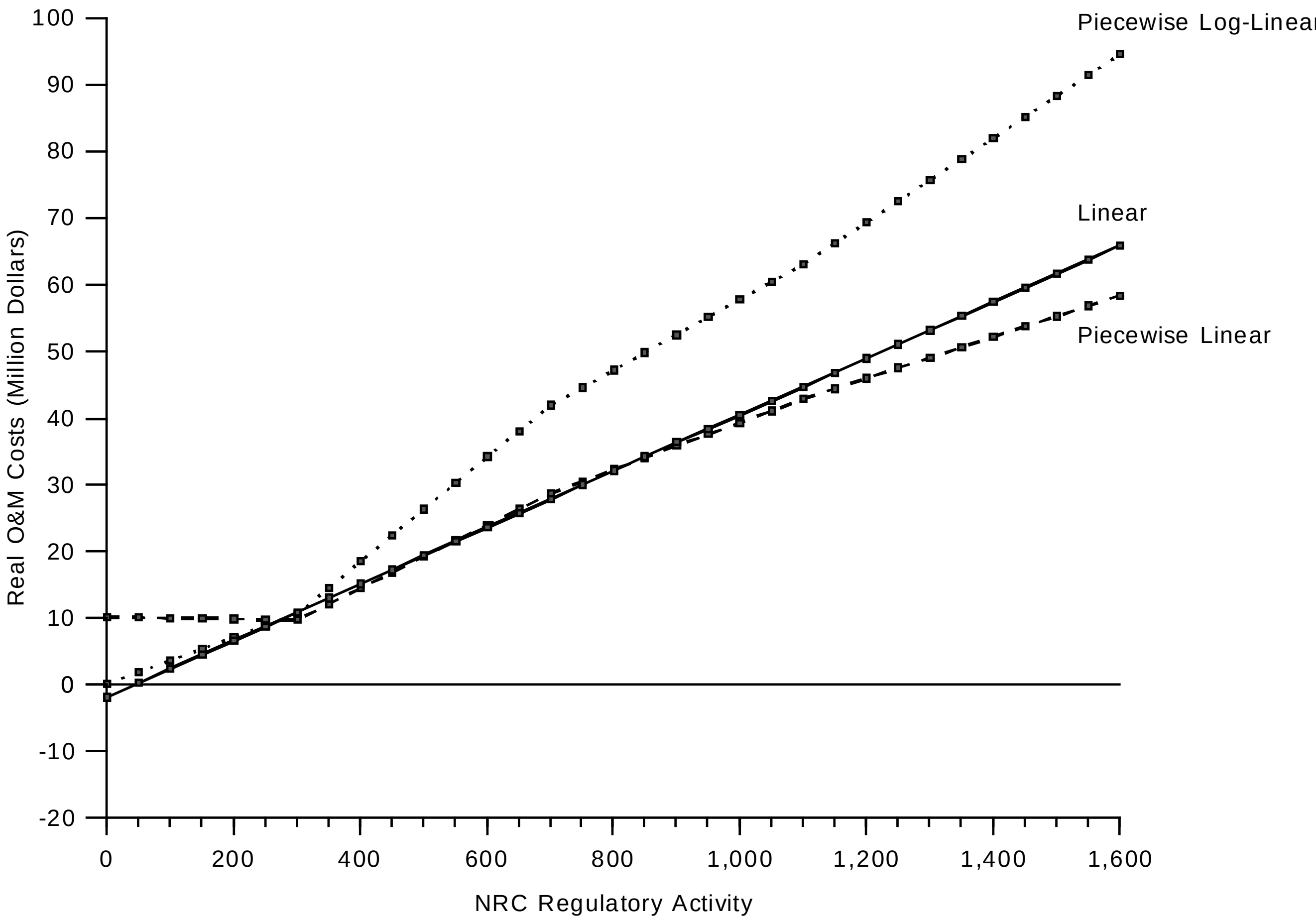
Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute.

that there are statistically significant, negative aging effects. However, when this model was reestimated with data through 1991, aging was no longer statistically significant. This observation would seem to suggest that the additional data caused the aging results to change.

The use of additional data was not the sole reason for the different aging results. First, when the new specification of the model was estimated with old data through 1984, the aging coefficient was not statistically significant (Table A6, column 3). Second, regardless of the specification and the endpoint of the data, when the new measure of the price of the O&M material was used, the age coefficient was not statistically significant. All of these results seem to suggest that the negative aging effect may have been an artifact of the time frame used in the original study, the specification of the model, and the measure of price of O&M materials.

With respect to the capital additions cost analysis, the original report found that the aging effects were limited to boiling-water reactors and ones using salt water as a source of secondary cooling, whereas the present report found aging effects for all reactor types. In the original study, the capital additions cost model was estimated using ordinary least squares, whereas fixed effects estimates were used in the present study. The

Figure A2. Relationship Between Operating and Maintenance Costs and NRC Regulatory Activity



Note: This graph shows the relationship between O&M costs and NRC regulatory activity based on three specifications of the model.

Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and predecessor survey forms; and Utility Data Institute.

differences in the results can be attributed to the use of different estimating techniques.

The first two columns in Table A7 show the estimates of a linear version of the capital additions model where the aging effect depends upon reactor type (i.e., boiling-water reactor versus pressurized-water reactor) and the source of secondary cooling (fresh versus salt water).[106] As was the case with the previous two studies, the OLS results suggest that the aging effects depend upon reactor type and source of cooling.[107] However, the fixed effects estimates show much larger aging effects that are invariant to reactor type or source of cooling.

[106]The linear and log-linear specifications produced similar results. The linear specification was used because the dummy variables can be more easily interpreted.

[107]Note that although the aging effects do depend upon reactor type and source of cooling, in neither case are aging effects positive and statistically significant.

Table A6. Comparison of 1984 and 1994 Specifications

Variable	Specification[a]				
	A	B	C	D	E
Plant Age	-3290.82 (1,595.34)*	3,140.674 (1,520.52)*	-1,791.6 (1,670.43)	-293.532 (1,232.19)	2,398.603 (1,253.39)*
Price of Replacement Power	12,284.22 (7,956.02)	12,269.86 (8,172.72)	10,136.87 (7,832.76)	15,937.2 (8,006.2)*	11,301.4 (8,095.9)
Price of Replacement Power × Stringency of Public Utility Commission	792.1906 (1,963.17)	8,449.342 (2,162.81)*	-1,029.98 (1,906.85)	694.8724 (1,980.79)	8,333.29 (2,159.63)*
O&M Worker Wage Rate	378.6022 (1,141.42)	1,070.516 (1,108.77)	844.2711 (1,121.64)	779.3734 (1,138.87)	1,040.595 (1,109.88)
Price of O&M Materials	441.1244 (194.17)*	-132.626 (202.23)	38.31361 (201.348)	4.485762 (197.097)	2.945708 (262.182)
Fuel Price	NA --	NA --	36,673.66 (50,103.8)	NA --	NA --
Acquisition Price of Capital Good	-1,305.18 (713.356)*	-1,759.91 (613.183)*	-3,053.35 (915.062)*	-1,137.02 (715.828)	-1,781.93 (624.417)*
Cost of Capital	NA --	NA --	28,295.19 (54,155.7)	NA --	NA --
Change in Acquisition Price of Capital Good	NA --	NA --	1,942.67 (1,190.61)*	NA --	NA --
NRC Regulatory Activity or Industry Learning	302.9473 (83.5746)*	63.2087 (39.792)*	61.0634 (17.3039)*	196.9239 (80.5561)*	78.27333 (42.0646)*
Average NRC Fines to Year t-1	229.807 (45.8986)*	207.3317 (27.3746)*	209.6921 (45.4668)*	212.1022 (45.8793)*	209.4498 (27.3089)*
Incentive Rate of Return Binary Variable	2,072.986 (1,818.81)	10,920.68 (2,860.43)	547.0855 (1,814.775)	2,614.504 (1,868.266)	10,821.85 (2,884.08)*
Plant Size	3.55545 (4.25883)	27.14985 (5.21729)*	8.259817 (4.24304)*	10.14575 (3.51201)*	25.29671 (4.66425)*
Experience at Other Plants Owned by the Same Utility	-286.192 (219.709)	191.3818 (190.875)	-167.968 (219.8262)	-242.667 (222.044)	181.7094 (190.3842)
Retrofit Binary Variable	NA --	NA --	8,068.763 (6,019.367)	NA --	NA --
O&M Costs in Year t-1	1.621938 (0.11089)*	0.747255 (0.06946)*	0.647228 (0.04416)*	1.623241 (0.11204)*	0.749337 (0.06959)*
Constant	NA --	NA --	NA --	NA --	NA --
R-Squared	0.86	0.80	0.86	0.85	0.80

[a]Specifications: A = old specification with 1984 data and old material price data; B = old specification with 1991 data and old material price data; C = new specification with 1984 data and old material price data; D = old specification with 1984 data and new material price data; E = old specification with 1991 data and new material price data.

Note: Standard errors are shown in parentheses. An asterisk (*) indicates that the coefficient is significant at the 0.95 level of confidence using a one-tailed test. In the old specification, the square of time was used as a measure of regulation, and average O&M costs from year i to year t-1 were used instead of O&M costs in year t-1.

These results clearly suggest that some cross-sectional variable is correlated with age. An examination of the cross-sectional intercepts suggested that the older vintage plants had lower capital additions costs.[108] Thus, the age of the plant as of 1992 was included as an explanatory variable, and this vintaging effect was allowed to vary by reactor type and source of cooling. The OLS results shown in column 5 of Table A7 suggest that older vintage plants have lower capital additions costs and that this negative vintage effect is

[108]There are a number of explanations for this result. First, the design of the older vintage plants was much simpler, and therefore, were much earlier to repair. Additionally, since the age distribution was not constant across regions, the vintaging variable could also be capturing regional factors.

Table A7. Ordinary Least Squares and Fixed Effects Estimates of the Aging Effect

Variable	Specification					
	Two Age Variables		One Age Variable		Maximum Age Variables	
	OLS	Fixed Effects	OLS	Fixed Effects	OLS	Fixed Effects
Plant Age	-0.62095 (0.42892)	8.80061 (1.82889)	-0.22613 (0.41697)	9.03791 (1.78873)*	2.02872 (0.76143)*	9.03664 (1.7932)*
Plant Age × Saltwater Cooling Dummy	0.423204 (0.23265)*	-0.39732 (0.57901)	NA --	NA --	NA --	NA --
Plant Age × BWR Dummy	0.648933 (0.21283)*	0.452945 (0.53519)	NA --	NA --	NA --	NA --
Price of Replacement Power	12.0199 (15.8391)	20.861 (15.0641)	12.6732 (15.9562)	20.688 (15.0477)	12.4041 (15.7026)	20.8375 (15.0946)
Price of Replacement Power × Stringency of Public Utility Commission	0.381927 (3.86312)	0.725574 (3.69931)	0.072254 (3.89131)	0.582377 (3.69369)	0.101214 (3.8302)	0.595161 (3.70286)
O&M Worker Wage Rate	-1.34954 (2.1546)	-4.00974 (2.06105)*	-1.51068 (2.16865)	-4.1609 (2.05435)*	-1.68934 (2.1371)	-4.16657 (2.06342)*
Price of O&M Materials	-0.71432 (0.51858)	-0.27653 (0.49058)	-0.7334 (0.52245)	-0.24734 (0.48883)	-0.6908 (0.51443)	-0.24414 (0.4902)
Acquisition Price of Capital Good	0.705679 (2.11739)	0.166788 (2.16236)	1.50586 (2.1124)	0.07999 (2.12849)	0.667627 (2.08757)	0.104952 (2.13606)
Cost of Capital	9.22813 (30.3284)	-9.08815 (28.9081)	7.23676 (30.5394)	-12.4844 (28.7135)	6.08637 (30.1723)	-12.1582 (28.8031)
Fuel Price	116.569 (89.0114)	71.6064 (85.8645)	117.959 (89.6841)	69.8043 (85.7533)	108.574 (88.3162)	70.1329 (85.9653)
NRC Regulatory Activity	0.001072 (0.00475)	-0.08969 (0.01876)*	-0.00177 (0.00471)	-0.09191 (0.01858)*	-0.02036 (0.00747)	-0.09184 (0.01862)*
Cumulative NRC Fines to Year t-1	18.9331 (4.8538)*	24.0594 (6.38017)*	23.3607 (4.71699)*	24.1168 (6.15237)*	18.2202 (4.76294)*	24.1286 (6.16742)*
Use of Incentive Rate of Return	11.3739 (2.99601)*	16.3167 (4.63606)*	12.5401 (2.85517)*	15.3446 (4.48223)*	10.4672 (2.94929)*	15.3442 (4.49281)*
Experience at Other Plants Owned by the Same Utility	0.030484 (0.06254)	0.048625 (0.14653)	0.058187 (0.06167)	0.086651 (0.14217)	0.037805 (0.06156)	0.084908 (0.14265)
Plant Size	-15.2973 (2.64745)*	24.098 (11.0767)*	-15.4262 (2.6637)*	24.3753 (11.0664)*	-14.6352 (2.63018)*	24.4613 (11.0967)*
New Plant Binary Variable	2.06372 (5.89734)	NA --	3.61362 (5.91935)	NA --	1.93267 (5.85533)	NA --
Steam Generator Binary Variable	72.8516 (7.88957)*	72.0104 (7.56372)*	73.434 (7.94031)*	72.2582 (7.55523)*	72.3177 (7.82538)*	72.1316 (7.58793)*
Maximum Age	NA --	NA --	NA --	NA --	-2.55396 (0.64313)*	NA --
Maximum Age × Saltwater Cooling Dummy	NA --	NA --	NA --	NA --	0.388231 (0.1441)*	NA --
Maximum Age × BWR Dummy	NA --	NA --	NA --	NA --	0.332305 (0.13544)*	NA --
Constant	128.279 (19.3466)	NA --	129.273 (19.4622)*	NA --	158.399 (20.7362)*	NA --
Adjusted R-Squared	0.34	0.31	0.33	0.30	0.34	0.31
Hausman M-Statistic	NA	NA	NA	38.5	NA	21.2

Note: Standard errors are shown in parentheses. An asterisk (*) indicates that the coefficient is significant at the 0.95 level of confidence using a one-tailed test.

less for boiling-water reactors and ones that use salt water as a source of cooling. Column 3 shows that when these variables are not included, no aging effects are observed. However, when these vintaging variables are included, the plant age coefficient is positive and significant.

It is also interesting to note that although the OLS and fixed effects estimates of the aging effects are positive in the specification that includes the vintaging variables, the order of magnitude of the estimates is quite different. Additionally, the Hausman specification error test indicates that the null hypothesis of no specification error cannot be rejected, suggesting that there are other cross-sectional variables influencing capital additions costs that are correlated with age.

Estimates of Scale Effects

As noted in the text, the fixed effects estimates of the plant size effects are very difficult to interpret. This is because the only time the size of the plant changed was when an additional unit at the same site was added. Additionally, most of the smaller plants had just one unit on site, while most of larger ones had two or more units. Since there are probably economies from having more than one unit on site, the plant size coefficient is measuring classic economies of scale and economies from having more than one unit. Finally, the Hausman specification error test suggests that an unmeasurable cross-sectional factor may be correlated with one or more of the independent variables. Most of the bias is probably being captured in the age coefficient. It is possible, however, that the size coefficient may also be biased.

Because of the interest in estimates of the economies of size effect, they will still be presented. It is interesting to note that the size coefficient in the GLS and fixed effects estimates of the O&M equation (Table A1) are very similar. The estimated scale effect, computed from the GLS estimate, was about -0.7. That is, a 1-percent increase in plant size was associated with a 0.7-percent decrease in costs per kilowatt of capacity. The estimated scale effect from the GLS estimates of a log-log version of the model was about -0.5.

The fixed effects and GLS estimates of the size coefficient in the capital additions equation were quite different. Since the size coefficient in the OLS estimate did not change when the cross-sectional vintaging variables were added, the size coefficient is probably not seriously biased (Table A7). The estimated scale effect computed from the GLS estimates shown in Table A2 suggests that a 1-percent increase in plant size was associated with a 0.5-percent decrease in real capital additions per kilowatt of capacity.

Data Issues

One problem common to all analyses of electric power generating technologies is the availability of plant-specific input price data. Plant-specific fuel price data are reported to the Federal Government and are used here. The price data for the other inputs were obtained from several secondary sources. Postoperational capital expenditures tend to be very labor intensive, and, therefore, the wage rates of skilled construction labor in the area surrounding the plant were used as a proxy for the acquisition price of the investment good. These data were obtained from the trade publication, *Engineering News Report*.

As noted above, O&M expenditures are 75 percent labor-related. The remaining 25 percent are for a variety of materials used mainly for small construction projects. Plant-specific data on wage rates of the onsite staff obtained from the union representing the workers in 75 percent of the plants in the sample were used. The price of ready-mix concrete in the area surrounding the plant was used as a proxy for the price of the O&M materials input. Again, this data series was obtained from *Engineering News Report*. Although this proxy is far from perfect, it is the only regional one available over the entire 1975-1992 period.

There are two sources of data that reflect replacement power costs for nuclear power plants. First, the quantities and revenues of sales of electricity for resale are published annually at the utility level in EIA's *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*.[109] These data essentially measure the sales and amounts of wholesale power that are sold to other utilities and, thus, should measure the cost of replacement power. The only other data source is plant-specific estimates of the cost of replacing power from a nuclear power plant that is shut down for a short time period.[110] These data are available for the years 1984,

[109]Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*, DOE/EIA-0437 (various issues).
[110]U.S. Nuclear Regulatory Commission, *Replacement Power Costs for Nuclear Electricity-Generating Units in the United States*, NUREG/CR-4012 (Washington, DC, November 1991).

1987, and 1990. These estimates, prepared for the NRC, are used by them to compute the cost of regulations that require a nuclear plant to be taken out of service.

As was noted in the 1988 report a comparison was made of about 10 percent of the published data on the price of bulk power sales with unpublished data; in most cases, the former was much lower than the latter. However, the publicly available data on the price of power for resale tended to move over time with fossil fuel prices. Additionally, some spot checks of the replacement power data found in the NRC publication suggested that these estimates are representative of marginal replacement power costs for short outages. The regional variations in the NRC data were also consistent with the price of the dominant fuel in that area.

These comparisons suggest that the NRC data were better measures of the level of replacement power costs. Variations in the price of power for resale were correlated with variations in fossil fuel prices and therefore reflect changes in replacement power prices over time. Consequently, the NRC data were used to measure 1990 replacement power prices. The percentage change in the price of power for resale was used to compute the levels for the other years. The means of all the variables of importance used in the analysis, along with the units, are shown in Table A8.

Deflation Issues

Another data issue deals with the deflation of the costs and the use of costs per kilowatt versus costs per kilowatthour. In this report, two slightly different definitions of real costs were used. In Chapter 2, the O&M and capital additions cost data were deflated using the GDP Implicit Price Deflator. Changes in this measure of real costs reflect changes in quantities of the O&M input (i.e., O&M labor and materials) plus changes in the prices of the inputs relative to changes in the overall rate of inflation. In economics, changes in real costs only reflect changes in quantities. Thus, the measure of real costs used in Chapter 2 is slightly different from the one used in economics.

As discussed in Chapter 3, the O&M cost data were implicitly deflated with measures of prices of O&M materials and O&M employee wage rates. Since the procedure used to implicitly deflate the O&M costs in Chapter 3 controls for changes in prices, any remaining variations are due to changes in quantities.

To determine whether the results of interest were sensitive to the method used to deflate the costs, two additional deflators were used. The first, the Handy-Whitman regional index for the wages of skilled electrical workers, was used to deflate the O&M costs. The capital additions costs were also deflated using the

Table A8. Means of Variables of Importance Used in the Analysis

Variable	Mean	Units
O&M Costs	64,304.14	Thousand dollars
Real Capital Additions Costs per Kilowatt of Plant Capacity	14.58	Dollars
O&M Worker Wage Rate	13.51525	Dollars
Price of O&M Materials	42.95597	Dollars
Industry Experience	615.6567	Years
Cumulative Number of NRC Regulatory Actions	817.1111	--
Price of Capital Good	15.42253	Dollars
Price of Fuel	0.048478	Dollars per kilowatthour
Average NRC Fines to Year t-1	19.14713	Thousand dollars
Plant Size	1,223.819	Megawatts
Rating of Public Service Commission	2.511228	--
Plant Age	9.194894	Years
Price of Replacement Power	0.34325	Dollars per kilowatt

Handy-Whitman index for reinforced concrete building construction. The tabulations of real O&M and capital additions costs using these deflators were similar to those shown in Tables 1 and 2 and Figures 1 and 2 in the body of the report.

Additionally, if the labor wage rate variable in the O&M equation was measured with substantial amounts of error, it is possible that some of the escalation attributed to NRC regulatory activity might be due to simple inflation. Thus, the O&M cost model was reestimated with O&M costs deflated with the Handy-Whitman Index for skilled electrical workers. These results are shown Tables A5 and A9 and Figure A1. The year-to-year changes in the residual escalation in costs depicted in Figure A1 tended to be more erratic. It was therefore not surprising that the NRC regulatory actions coefficient in Table A9 was relatively smaller. The O&M labor and material input elasticities were also substantially less than the ones presented in the text. Again, this was due to the lack of variability in the changes in these wages and prices.

There are also two reasons why the data in Chapter 2 are expressed in costs per kilowatt of installed capacity (as opposed to costs per unit of plant output). First, in the short run, staffing levels and O&M materials are invariant with the level of output. Thus, the O&M costs per kilowatthour of output for plants that were out of service for long time periods would approach infinity, and as a result, any traditional measure of the central tendency (i.e., mean, median, or mode) would be very difficult to interpret.[111] Second, to the extent that staffing levels, etc., are invariant with the level of output, changes in real O&M costs per kilowatthour of output could be due to unrelated factors that just influence plant performance. Additionally, in the long run, increases in staffing levels, etc. (the numerator) result in improved plant performance (the denominator). Thus, changes in O&M costs per kilowatthour of output actually reflect changes in labor productivity. In short, changes in real O&M costs per kilowatt of installed capacity reflect changes in quantities of the O&M inputs, whereas changes in real O&M costs per kilowatthour measure changes in productivity.

Methods Used To Predict Costs

The procedure used to "predict" what O&M costs would have been was straightforward. The regression results presented in Table 9, along with the yearly arithmetic means computed for all the plants in the sample, were used to "predict" total costs. Then, the mean net capacity was used to compute costs per kilowatt. (This mean will be different from the ones shown in Chapter 2, where costs per kilowatt were computed at the plant level.) Then, the arithmetic mean was computed.

The prediction of what capital additions costs would have been was more involved. First, because the relationships between age and costs and between learning and costs were not linear, there was the potential for serious aggregation bias. Thus, five subsamples of plants with roughly equal vintages were derived. Then, the regression results presented in Table 19 and the yearly means were used to "predict" costs for each subsample. Finally, costs for the entire sample were computed by taking weighted averages of the costs for each subsample. The numbers of plants in each subsample were used as weights.

The yearly means used in Chapter 4 are slightly different from the ones presented in Chapter 2. First, the means computed in Chapter 4 were computed using the same data employed in the regression analysis. Because of some missing data for some of the explanatory variables, there will be some minor differences between the O&M cost samples used in Chapters 2 and 3. Additionally, the tabulations of capital additions costs shown in Chapter 2 included the 50 or so observations with negative capital additions. These observations were not used in the statistical analysis presented in Chapter 3. Moreover, to compute the yearly means per kilowatt of plant capacity used in Chapter 4, the mean total nominal O&M costs were divided by the mean net capacity. This figure was then deflated. Alternatively, in Chapter 2, real costs per kilowatt of gross capacity were computed at the plant level. The means shown in Chapter 2 were then computed.

[111]Most analyses using costs per kilowatthour compute an average by dividing total O&M expenditures for the industry by total generation for the industry. This is equivalent to a generation-weighted mean. Because the weights will change over time, it is very difficult to interpret changes over time in the generation-weighted mean.

Table A9. Estimates of the Operating and Maintenance Cost Model With Deflated Costs

Variable	Estimate
Plant Age	1,730.848 (1,850.9)
Price of Replacement Power	16,822.63 (10,538.2)*
Price of Replacement Power × Stringency of Public Utility Commission	5,087.432 (3,188.39)
Price of Replacement Power × Use of Fuel Adjustment Clause	-11,669.7 (10,168.1)
Price of Replacement Power × Use of Fuel Adjustment Clause × Stringency of Public Utility Commission	2,967.308 (3,885.99)
O&M Worker Wage Rate	-552.307 (1,233.08)
Price of O&M Materials	78.29623 (265.094)
Fuel Price	227,327.5 (54,793.3)*
Acquisition Price of Capital Good	-3,073.39 (733.843)*
Change in Acquisition Price of Capital Good	2,684.448 (1,503.68)*
Interest Rate	46,948.18 (46,795.6)
Cumulative Number of NRC Actions	28.70321 (16.4825)*
Average NRC Fines to Year t-1	123.0866 (29.4724)*
Plant Size	23.23186 (5.79041)*
Incentive Rate of Return Binary Variable	8,622.833 (3,130.98)*
Experience at Other Plants Owned by the Same Utility	39.33929 205.3875
Retrofit Binary Variable	16,168.77 (4,178.41)*
O&M Costs in Year t-1	0.402223 (0.02982)*
Constant	NA
R-Squared	0.77

Note: Standard errors are shown in parentheses. An asterisk (*) indicates that the coefficient is significant at the 0.95 level of confidence using a one-tailed test.