Nuclear Power Plants and Implications of Early Shutdown for Future Natural Gas Demand

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PREFACE

This report, commissioned by the INGAA Foundation, attempts to determine the future competitiveness of the 71 American nuclear generating sites. During the 1990s, operational efficiency and performance of many of the 110 U.S. reactors dramatically improved. But with increasing competition, there is widespread concern about the future competitiveness of some of these units.

The analysis done by the Washington International Energy Group is based on conservative estimates of the performance of plants and the prices those plants will compete against in the region they sell their output. The analysis assumes that operation and maintenance (O&M) costs will stay at the levels of 1993 to 1995 for all plants. It assumes that electricity prices will remain stable until 2005 despite a widespread assumption that prices will decline. It assumes a 10-year period (including internal preparation) for extending reactor licenses, even though there is a common belief that it may take longer. And, it assumes that extensive stranded cost recovery will be permitted so that utilities will be able to operate generating stations on a marginal cost basis without the burden of associated debt and other legacies of the past. Even with these conservative assumptions, a number of nuclear plants are vulnerable to shutdown. We assume that some utility decision-makers, as has already been the case, will conclude that the benefits of shutting down a plant sometimes exceed those of continued operation.

We further assume that there will **not be:**

- safety problems requiring long term or permanent shutdown at a facility;
- costly generic retrofits;
- complete political gridlock on resolution of waste management; or
- onerous financial requirements imposed by the Nuclear Regulatory Commission (NRC) in responding to the move to competition.

The U.S. nuclear industry is sensitive to criticism and has often tried to create a perception that all nuclear plants are under a common rubric. This report concludes that many competitive nuclear plants will almost certainly operate profitably for the foreseeable future. There are also some plants which simply may not be competitive. The majority of other plants, we believe, will continue to assist in meeting the nation's power supply requirements.

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Executive Summary

The nuclear power industry, along with the rest of the North American utility industry, is moving to a highly competitive, price-driven environment. Often perceived as a monolith, in this industry, like others, there are winners and losers. Despite very impressive improvements in O&M costs and output in recent years, the study found that among the 54 sites that are top or good performers, 20 are vulnerable to shutdown because projected annual production costs are higher than projected prices in the market. In addition, 17 sites that have a poor performance record over the past several years are vulnerable to shutdown, again because production costs are higher than the market price each will face. Some of these sites may be able to improve performance and survive.

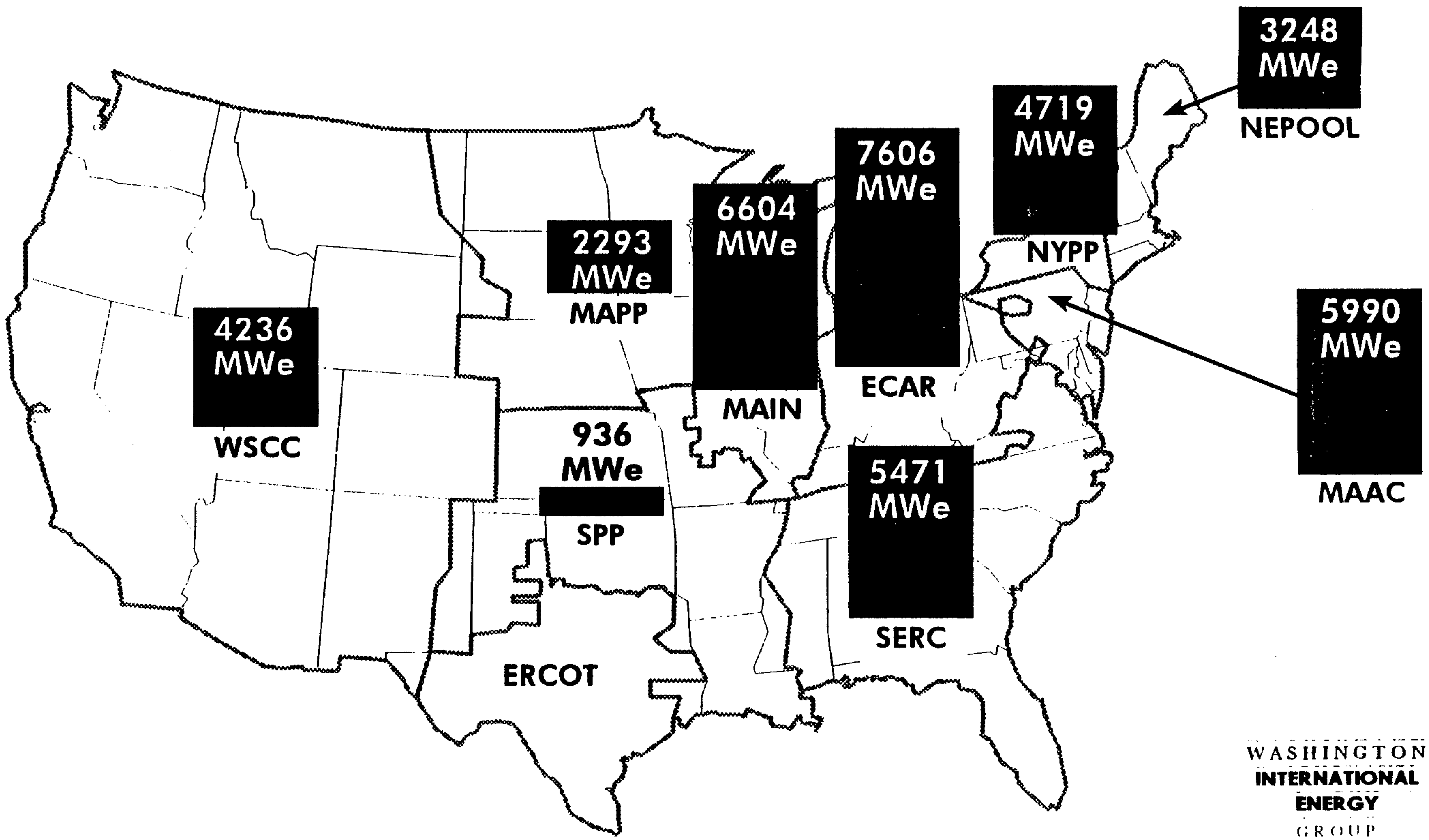
These 37 sites represent 40 percent of the nuclear generating capacity in the United States, providing just over 40,000 megawatts (mW) of generating capacity that produced nearly 250,000 megawatt hours (mWh) of electricity annually in the 1993 to 1995 time period. The need for additional capacity is of interest to the gas industry because of the potential market for natural gas. If all 37 sites close down, there would be opportunities for up to 1.55 trillion cubic feet (tcf) of natural gas use per year in electricity generation, which is equivalent to approximately 45 percent of the natural gas used for electricity generation in 1995. Realistically, increased demand for gas would be lower since improved efficiency in the electric industry will reduce the need for a one-to-one replacement and will compete against other facilities.

Important regional concentrations are evident in nuclear site shutdown. The vast majority is in the Northeast and Midwest, where 1.16 tcf of the total gas potential is found. Including the Southeast, north of Florida, adds another 0.21 tcf of potential.

These sites are vulnerable to shutdown because the market price each is likely to face in their particular region will be less than their annual production costs, even if prices remain level—which most experts believe is unlikely. The study looks only at actual operating costs and assumes stranded cost recovery and other means of reducing corporate debt are not direct factors in affecting the shutdown decision on individual plants. Of course, poor corporate performance may negatively affect nuclear facilities.

Besides economic performance and market competition, a number of other external dynamics were analyzed to determine if they would affect shutdown. These include shortage of capacity for on-site storage of nuclear waste, the need to renew the NRC license, decommissioning requirements, and low safety performance as rated by NRC. When combined with other problems, these may lead an owner to shut down a facility. However, none of these in isolation is likely to force the decision.

MWe Of Nuclear Capacity Vulnerable To Shutdown By NERC Region



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BACKGROUND

Improving Industry Performance

The nuclear power industry, along with the rest of the North American electric power industry, is in a transition from its regulated status to a highly competitive price-driven market world.[1] For the nuclear industry, the move to improved performance began in the 1980s as it became obvious that continuously increasing O&M costs along with constant infusions of capital, was turning the industry into an unacceptable burden for stockholders and ratepayers.

Compared with the gloomy outlook in the mid 1980s, recent years have shown significant improvements in the performance of the industry. Consistently, each year for the past six years, average O&M costs are down, output is up, and some nuclear plants are now the least costly to operate of all baseload generating plants. Many nuclear facilities are positioned well for the coming transition to competitive markets.

The traditional mind set of the industry was that plant costs were largely determined by outside forces—safety and economic regulation by state and federal agencies, nuclear fuel supplier market dynamics, advocacy groups opposing nuclear power, and others.

Reflecting this philosophy is a widely cited study by the Energy Information Administration.[2] This study was done to isolate individual causes of plant costs so that overall costs could be forecast. The most significant factors were plant aging, NRC regulatory activity, and state regulatory incentives to improve performance.

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[1] The Washington International Energy Group, *1997 Electric Industry Outlook*, January 1997, p. 5.

[2] "An Analysis of Nuclear Plant Operating Costs: A 1995 Update," *EIA Service Report*, SR/OIAF/95-01, Energy Information Administration, U.S. Dept. of Energy, April 1995.

More recently, a statistical analysis of nuclear plant performance leads off with, "dwindling economic competitiveness has plagued the nuclear industry for some years."[3] That study focused on time related factors, number of units per site, reactor type, unit size, vintage, and region—none of which an owner or manager can do anything about.

Neither of these studies addresses the changes that have occurred in the industry. Although both use sophisticated statistical techniques, they do not consider factors outside the traditional variables of statistical analysis, such as refocused corporate goals and changes in the marketplace. Another flaw in these studies is that they include the entire history of the industry. That approach overlooks the major changes that have taken place over the past few years. We strongly believe that the performance in recent years is a more reliable indicator of the future than is the entire 30-year commercial history of the industry. By missing the improvement that characterized recent performance, these analyses paint a dim picture of prospects for improving the economics of individual plants.

Paradigm Shift in the Middle to Late 1980s

The paradigm shift from a focus on external factors to one of owner and manager control began in the middle to late 1980s when the industry began to exert greater control over cost and performance. It was the philosophy that the industry could do more to control its own destiny. Inter-industry analyses were initiated to examine what could be done to cut costs and improve the economic performance of individual plants. Conferences were held to exchange information, studies were initiated to identify best industry practices, and project management practices were shared between plants and owners. Performance began to be seen as more than just technical competence; management savvy became the critical variable for success. Outside experts were called upon to instill positive thinking and a can-do attitude.

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[3] "Numbers that Make Sense: Gauging Nuclear Cost Performance," by Michael R. Fox and J.P.M. Maidmont, *Public Utilities Fortnightly*, Public Utilities Reports, Inc., June 15, 1996, p. 15.

The industry is now moving into a new phase of management reform characterized by joint actions and consolidation. Nuclear power remains expensive but centralization of control and innovative teaming efforts may be successful in cutting costs even further. What follows are some examples of efforts toward improving future performance.

- Companies owning nuclear units at more than one site are consolidating all nuclear plants into one operating division to provide nuclear expertise and a single nuclear management team at the corporate level. GPU was the first to do this after the Three Mile Island (TMI) accident as a means of company survival. In the late 1980s, Entergy embarked on this path. Since the predecessor companies typically owned a single nuclear site, the first step was to purchase other nuclear-owning utilities to concentrate all the company's nuclear expertise in management and operations in one organization.

- Mergers and acquisitions are occurring among electric utilities to reduce overall costs; about 10 have been initiated within the past year. The process is in its infancy, however. One situation is the merger of companies having similar nuclear commitments for the purpose of concentrating nuclear expertise, exemplified by the proposal of Centerior Energy and Ohio Edison to form FirstEnergy. Both companies have significant nuclear investment. They hope to save $1 billion over the first 10 years.[4]

  Another situation is the merger of nuclear with non-nuclear utilities to provide important economies of scale for competing in the future. Such an arrangement can provide complementary peak and baseload generating capabilities, and reduce stranded cost exposure. This is exemplified by the proposed merger of Baltimore Gas & Electric and Potomac Electric, whereby their contiguous market areas and fuel diversity are cited as the main benefits of the merger.

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[4] "Centerior Energy, Ohio Edison Announce $4.8-Billion Merger to Form FirstEnergy," *Electric Power Daily*, The McGraw-Hill Companies, Sept. 17, 1996, p. 1, and "Are Mergers Alike? Not in Ohio Edison-Centerior Deal," *The Energy Daily*, King Publishing Group, September 17, 1996, p. 1.

Discussions are being held among some smaller utilities, each owning one or more nuclear facilities, to explore merging or consolidating nuclear operations to achieve the benefits of a larger company. If such a venture is successful, it could improve the viability of some of the individual facilities and thus some of the conclusions of this report.

- A further initiative is the formation of cross-utility organizations to concentrate nuclear experience and make it available to participating utilities. Such formations, now in initial stages, include pooled buying as well as inventorying and sharing of specialized engineering services, in which teams of specialists provide service for the other participating utilities. The Utilities Service Alliance (USA) is the farthest along in cross-utility efforts. Other groups are the Northeast Energy Alliance and a group formed by Duke Power, Virginia Power, and South Carolina Electric and Gas.[5]

- Another initiative is exemplified by the January 1997 announcement that Maine Yankee Atomic Power Co. has hired Entergy Operations to manage the troubled Maine Yankee facility.[6] Entergy is generally recognized as a good manager of its nuclear facilities. The concept could bring major changes to plants whose performance is below that necessary to survive. There have been other similar plans, including an aborted plan by Entergy and New York Power Authority (NYPA) for Entergy to manage the Indian Point Unit 3 for NYPA, a sometimes troubled facility.[7]

- Next are joint efforts to improve plant performance. Under the sponsorship of the Nuclear Energy Institute (NEI), industry wide

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[5] "Justice Okays Eight Utilities' Bid to Merge Buying, Resource Sharing," *Nucleonics Week*, The McGraw-Hill Companies, July 18, 1996, p. 3.

[6] "Entergy to the Rescue in Maine," *The Electricity Daily*, The Electricity Journal, January 10, 1997, p. 1.

[7] "Entergy, NYPA Announce Precedent-Setting Nuclear Pact," *The Energy Daily*, King Publishing Group, August 1, 1996, p. 1.

benchmarking studies will identify best practices and evaluate how these can be transferred to other plants. The objectives are to:

- identify plants that have performed best at a substantially lower cost than the average;
- conduct site visits to a number of these plants; and
- communicate the results of the plant visits to the entire industry.

The first two objectives seem to have been met and the third is under way. Various aspects of plant operations were selected for evaluation to determine which plants were "best-in-class." These aspects are: Operations, Maintenance, Engineering, HP/Radwaste, and Training. Reports of the site visits have such titles as, "How the Best Plants Minimize Errors, Efficiently Schedule Work and Enhance Communications to Boost Performance," "How the Best Plants Increase Wrench Time, Cut Backlogs, Boost Moral," "How the Best Plants Cut Dose, Trim Costs, Boost Worker Safety," and "How the Best Plants Train Their Employees for Top Performance."

The culture of modern management, including total quality management (TQM), is evident in this project. That is, emphasis is given to systems engineering, corporate cultures that emphasize teamwork and communication, employee ownership of problems and empowerment to solve them, best-in-class plants, and encouragement of workers to perform tasks beyond work-classification bounds.

▸ An earlier effort akin to benchmarking is the sharing of knowledge in performing specialized activities. The most noteworthy effort of this kind concerns refueling. Refueling time has been cut from a median duration of 83 days in 1989 to 55 days in 1994, a 33 percent reduction. In 1995, one unit refueled in 23 days.[8] More recently, PECO Energy announced that Peach Bottom 2 had

[8] *Sharpening The Competitive Edge,* Issue Brief, Nuclear Energy Institute, August 1995.

completed its refueling outage in a world record of 19 days and 10 hours.[9]

- Over the long run, nuclear owners can work with industry associations to reduce the cost of complying with NRC regulations, even changing some of the regulations that contribute little to public safety. Efforts have been made for some time to render the regulations less prescriptive and more results oriented. This process between the industry and NRC tends to be tortuous, yet its success can bring significant industry wide savings. One example is changing the requirement of containment leak rate testing from three times every 10 years to once every 10 years. According to the NEI, this change alone could save the industry as much as $1 billion over the next 15 years.[10]

- Finally, some utilities are moving aggressively to improve management and business practices by employing expertise from other industries that are experienced in cost controls and market development.

Accomplishments Not Shared by All Facilities

The major improvements that characterize our analysis have not been shared by all reactor owners or facilities. Although this study finds that a large number of facilities are cutting production cost per kWh and so are likely to be competitive in the evolving era of competition, a significant number have been plagued by low output, resulting in high cost per kWh. The latter, of course, are of primary interest in this report for identifying opportunities for natural gas use. Site-by-site examination in Chapter I shows the performance of facilities by categories.

Our analysis shows that good performance can be achieved regardless of some of the traditional factors usually examined, such as size, age, type of

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[9] *Peach Bottom Unit 2 Returns to Service After World Record Refueling Outage*, Press Release, PECO Energy Company, October 4, 1996.

[10] *Sharpening the Competitive Edge*, Issue Brief, Nuclear Energy Institute, August 1995.

reactor and regulatory issues. We conclude that the differences in cost and performance among facilities stem largely from differences in facility management and operation and that actions taken by owners and operators over time can improve performance, although lapses can also occur. Either way, significant changes in management approaches can make a difference.

In short, the Washington International Energy Group is convinced that management performance, not technology or other external factors, is the most critical variable in determining which plants will continue to operate. Although some units, due to location or size, may be inherently more vulnerable than others, any nuclear unit in the United States is capable of both operating at high capacity and of cutting cost at rates comparable to the better performers. Depending on how electricity is marketed, the somewhat higher operating costs of some units may be rolled into a system price that still allows a seller to compete in the increasingly price conscious markets that are now emerging.

The Best of Times for Nuclear Power Performance

Compared with the future, these are the "golden years" of performance for nuclear power. As competition takes hold, (1) prices in the regions in which these facilities will compete will at best stay at current levels and may decrease and become more uncertain, (2) firm sales will become more uncertain, and (3) regulated utilities will have to market products and services to customers rather than deal with public utilities commissions to set rates. Those utilities that have already cut costs and increased output are much better positioned for a competitive market than those that have not. It will be more difficult to devote the company's management and financial resources to facility improvements when competition threatens sales and revenue.

Although we cannot categorically state that those utilities most aggressively facing competition are also, in the cases where they own nuclear plants, the most likely to be successful, we believe that good performers tend to be successful players. Conversely, those sites where performance lags may tend to stay in that situation.

It is important to note that although cutting costs is often said to reduce safety, the Washington International Energy Group does not believe that competition will lead to a decline in safety or result in more plant closures. As an analogy, despite drastic cost cutting, marred by strikes and billions of dollars in annual losses, airline safety has not declined because of competition. In a recent presentation, NRC Chairman Shirley Jackson affirmed this point.[11]

Every industry is characterized by good and bad performers. The nuclear industry has tended to encourage a view that all nuclear plants are good performers and that failure at any plant will negatively affect the whole industry. As competition winnows out the winners and losers, the Washington International Energy Group believes it is important to highlight the strengths of the winners while candidly acknowledging that some nuclear units may not remain in service as long as others.

Regional Importance of Nuclear Power Generation

Before proceeding with the analysis, a regional perspective is needed. The United States is a large country and generalized conclusions about market prices and circumstances are always risky.[12] Table B-1 shows the role of nuclear power in each region.[13] For the total United States, 14 percent of the electricity generating capacity is nuclear with 21 percent of the actual output coming from these plants. The kWh of output of nuclear facilities is a higher percentage of the total electricity output than is capacity of nuclear compared with total generating capacity, because of the much higher utilization of nuclear units (due to operation as baseload) than for the average.

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[11] *Talking Points on Industry Restructuring and the NRC*, by Shirley Ann Jackson, Chairman of the U.S. Nuclear Regulatory Commission, to the Washington International Energy Group, December 11, 1996.

[12] This analysis does not consider the Canadian nuclear industry's future nor does it focus on other transboundary issues. They are relevant factors, however.

[13] Taken from, *Assumptions for the Annual Energy Outlook 1996*, DOE/EA.-0554(96), Energy Information Administration, January 1996, Table 62.

Nuclear generation and capacity vary greatly by region. Regional dependency on nuclear is high in New England, where 25 percent of the capacity and 44 percent of the generation is nuclear. The highest concentration of nuclear power is in the MAIN national electrical reliability region, consisting of Illinois, eastern Missouri, and eastern and northern Wisconsin, and where nearly 30 percent of the capacity and 40 percent of the electricity are provided by nuclear power. Commonwealth Edison is in the MAIN region and operates 12 units at six sites. Other regions where nuclear power plays a significant role are New York, with 15 percent of the capacity and about 30 percent of the output; the MAAC region, consisting of Delaware, Maryland, New Jersey, and most of Pennsylvania (except the western part), with 25 percent of the capacity and 40 percent of the output; in the SERC region excluding Florida with slightly over 20 percent of the capacity and 30 percent of the output. These differences in regional dependence on nuclear are likely to be a factor in the acceptability of nuclear shutdowns by various state and regional interests.

Table B-1. Regional Nuclear Capacity and Output, Compared with Total, 1995

Region	Total Generating Capacity Gigawatts	Nuclear Generating Capacity Gigawatts	Percent Nuclear of Total Capacity	Generation Total Billion kWh	Generation Nuclear Billion kWh	Percent Nuclear of Total Generat.
New England	25.7	6.4	25	95.1	41.6	44
New York	33.0	4.9	15	108.1	31.3	29
Mid-Atlantic	54.0	12.7	24	216.0	85.1	39
Southeast, except FL	121.5	25.4	21	541.3	167.8	31
Florida	35.5	3.8	11	133.7	27.2	20
OH, MI, West. PA	108.0	7.6	7	529.1	49.1	9
KS, OK, AR, LA	73.1	5.9	8	274.7	42.3	15
IL, parts of WI, MO	51.4	14.8	29	238.2	95.4	40
MN, IA, NE, ND, SD	34.0	3.7	11	143.2	25.5	18
Most of Texas	53.9	4.8	9	225.1	28.5	13
Northwest	51.0	1.1	2	239.6	6.3	3
R Mountain & AZ	27.2	3.0	11	141.6	20.6	15
CA & NV	56.0	5.1	9	166.8	37.3	22
Total U.S.	724.2	99.2	14	3063.1	657.8	21.47

Data include utility and non-utility

Source: Assumptions for the Annual Energy Outlook 1996, DOE/EIA-0554(96) Energy Inforamtion Administration, January 1996.

The Industry Views

For the past six years, the Washington International Energy Group has conducted an annual survey of the electric power industry. Each year we have asked senior utility executives about their views of the future. Although optimism about the potential for new orders or a "resurgence" in the nuclear industry has sharply declined, there has been very little change in views about continued operation of existing units or about the percentage of plants that will be considered for license extension.[14] Respondents who said there would be a resurgence in nuclear power declined from 37 percent in 1994 to 8 percent for both 1996 and 1997. Figure B-1 at the end of this section shows these data. Similarly, as was the case last year, very few in the industry—2 to 3 percent—would ever consider ordering a new nuclear plant.

Industry representatives have also been asked whether they believe nuclear will be competitive in the future. Both those who own and those who do not own nuclear units responded. On this point, there is no consensus, with 44 percent responding "yes," 33 percent "no," and 23 percent "not sure." Representatives were also asked whether it was expected that nuclear plants would shut down prematurely. In 1996, 13 percent said "yes," and in 1997, 19 percent said "yes." The "no's" dropped from 66 percent in 1996 to 59 percent in 1997. Figures B-2 and B-3 at the end of this section show these data.

Concerns of the Financial Community

Emerging competition in electricity markets has raised a number of concerns among securities and investments analysts. In its 1994 annual report on the U.S. electric utility industry, Moody's Investor Service stratified nuclear owners into three groups regarding expectations for success in competitive markets. Moody's identified controlling production costs as the single most important factor for successful competition.[15]

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[14] *The 1997 Electric Industry Outlook*, Washington International Energy Group, pp. 34 & 35.

[15] Reported in, "Production Costs Point to Competitive Winners—Moody's," *The Energy Daily*, King Publishing Group, November 1,

However, well-conceived and executed marketing strategies are also important; a small number of companies combining low-cost production with effective marketing will prosper. At the other end of the spectrum will be companies whose financial flexibility will suffer from high-cost production and loss of customers. In the middle of the pack will be companies with average or above average costs but with imaginative marketing programs.

A more recent study by Moody's Investor Service expanded upon the analysis.[16] It concluded that the industry faces a troubled future, with questionable prospects for license renewal, the possibility of premature shutdowns, decommissioning costs, and uncertainties over nuclear waste disposal. It identified eight investor-owned nuclear utilities whose credit ratings have been upgraded since its last report in 1993. But 24 nuclear utilities were downgraded. Notwithstanding progress made by many of these utilities in lowering costs, cash costs remain high and may not be recoverable through rates in a more competitive market.

The report also expressed pessimism about prospects for license renewal. The benefits of having more time to accumulate decommissioning funds and the flexibility to stretch depreciation costs will likely be offset by significant additional capital investment, needed to meet future regulatory and operating requirements. The waste storage crisis reduces the likelihood a utility will extend its operating license. Moody's contends that many utilities face a genuine crisis on spent fuel storage.

For the 47 utilities that Moody's put into a significant risk category, the suggestions are to

- improve the company's financial flexibility to compensate for increased business risk and the potential for nuclear plant write-downs;

1994, p. 3.

[16] "Moody's Assesses Nuclear Power Risks In A More Competitive Market," reported in "Moody's: The Nuclear Picture is Not A Pretty One," *The Energy Daily*, King Publishing Group, Inc. November 22, 1996, p. 1.

- seek authorization to accelerate the amortization of deferred regulatory asset depreciation or both;

- cut the company's operating costs; and

- continue to push for a solution to the radioactive waste problem.

Ernst & Young has identified major issues which the industry faces.[17] Three major forces—market-based pricing, nuclear capital and operating costs, and stranded assets—will reshape the nuclear industry. If a utility makes timely and major changes in its nuclear performance, the negative financial impact of market-based pricing will be partially offset. The nuclear utility will find the transition from the current period to the future difficult, particularly in adopting behaviors for success. A panel of industry executives assessed the report and believes that the amount of change required will be significant, perhaps even radical. They also believe the industry in general is behind the pace necessary for a successful and timely transition.

Comparison with a Related Study

In a study done for the same general purpose as this one, much of the same data are analyzed, but with surprisingly different conclusions.[18] Whereas this report concludes that many nuclear facilities are vulnerable to shutdown, the American Gas Association (AGA) study concludes that the amount of nuclear capacity retired prematurely will be very small. The AGA study recognizes the importance of market prices (at $20/MWh, nuclear powerplants operating around $175/kW/year would be in danger).[19] However, the AGA study does not include a formal analysis to project how competitive market prices may effect individual plants. Our report includes such an analysis, and shows that several plants seem viable

[17] *Nuclear 2000, Transforming the Nuclear Power Industry to Ensure Competitiveness,* Ernst & Young LLP, undated report issued in October 1996.

[18] *Existing and Future Electric Generation: Implications for Natural Gas,* American Gas Association, Policy Analysis Group, October 1996.

[19] "Existing and Future Electric Generation: Implications for Natural Gas, *op. cit.*, p. 55.

when only considering cost and output performance, but are projected to be vulnerable to shutdown when forecasting the market prices to site production costs. We believe that this will affect owners decisions as to whether to shut down facilities. We believe that if the AGA study had undertaken that kind of analysis, a significantly greater number of plants would have been identified for shutdown. Beyond this, it is difficult to assess why the conclusions are so different. That report does a plant-by-plant analysis, just as our study does. A narrative review of a number of plants was done and a prognosis given for the shutdown potential for each, without a clear basis developed for the conclusions. For most, a prognosis was made that the plant will not be shut down. Here are examples of the reasons:

- Oyster Creek—It is performing well, and because of other nuclear supply problems in the Northeast, "it is unlikely that much thought would be given to prematurely retiring it while its performance is rapidly improving."

- Indian Point 2—Given the difficulty of constructing baseload capacity or new transmission anywhere near New York City, it is "worth keeping operational."

- Millstone 1 & 2—"Northeast Utilities cannot afford either economically or technically to prematurely retire the plants. Alternative forms of low cost baseload power are not available."

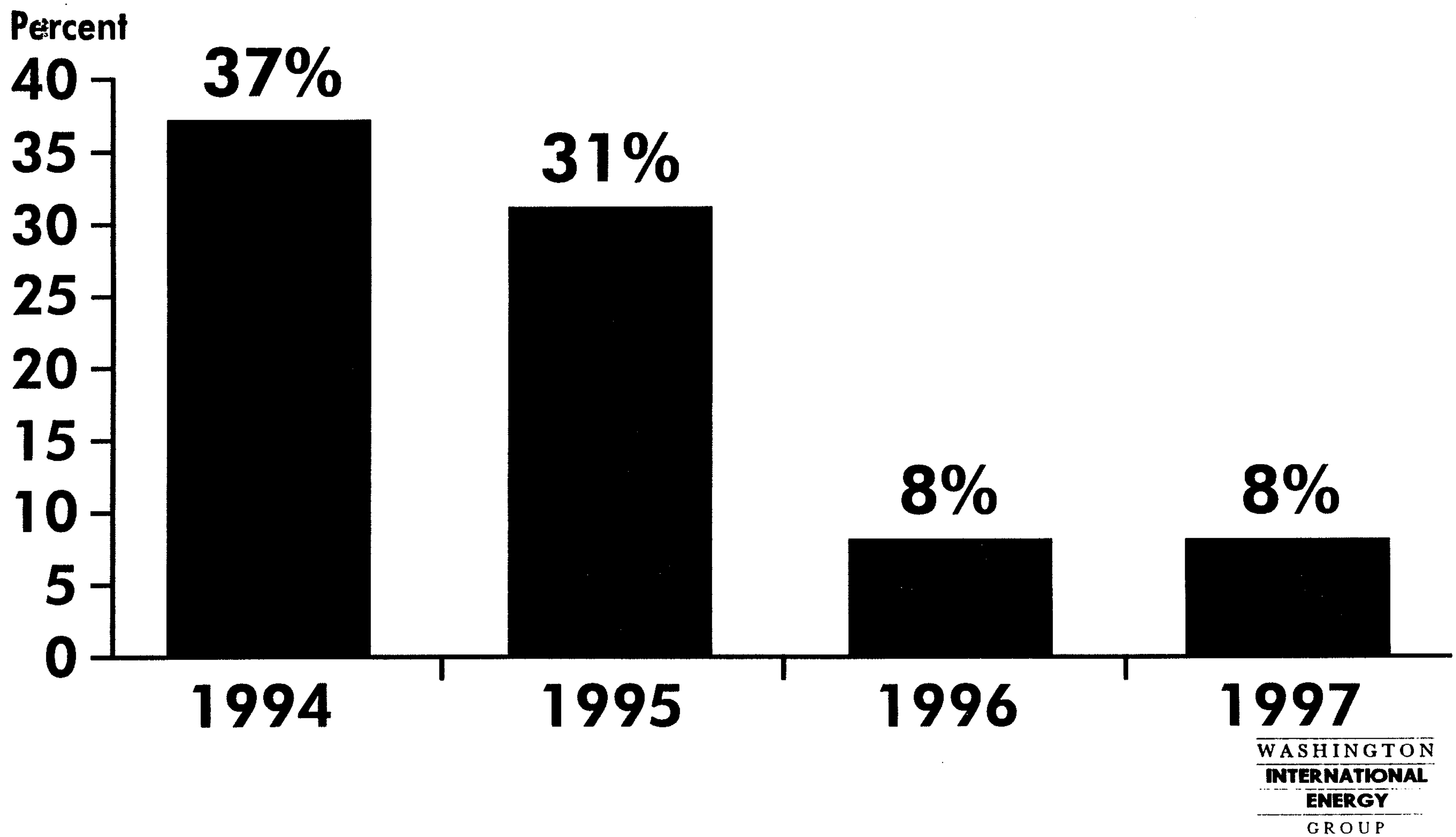
In some situations, plant retirements were predicted **only if** a competitive market emerges.

- Indian Point 3—The future depends on how the state deregulates retail generation and deals with preferences for municipal utilities.

- Dresden and Quad Cities—If Illinois permits retail wheeling soon, and can reach agreement with Commonwealth Edison to preserve its solvency, these plants would be at risk for premature shutdown.

Figure B-1

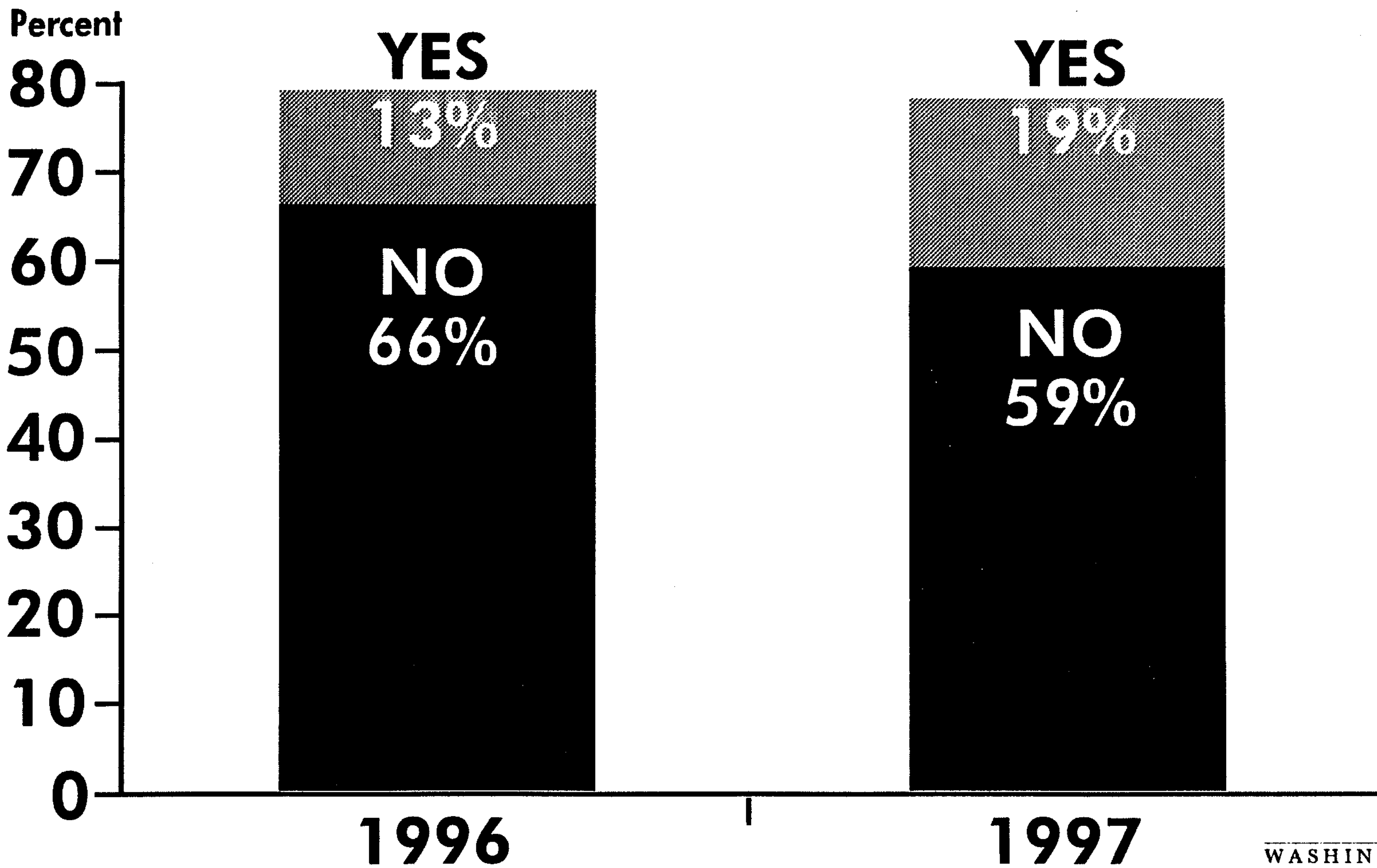
Executives Expecting A Nuclear Power Resurgence



Source: Washington International Energy Group, The 1997 Electric Industry OUTLOOK

Figure B-2

Executive Opinions On Nuclear Power Shutdowns



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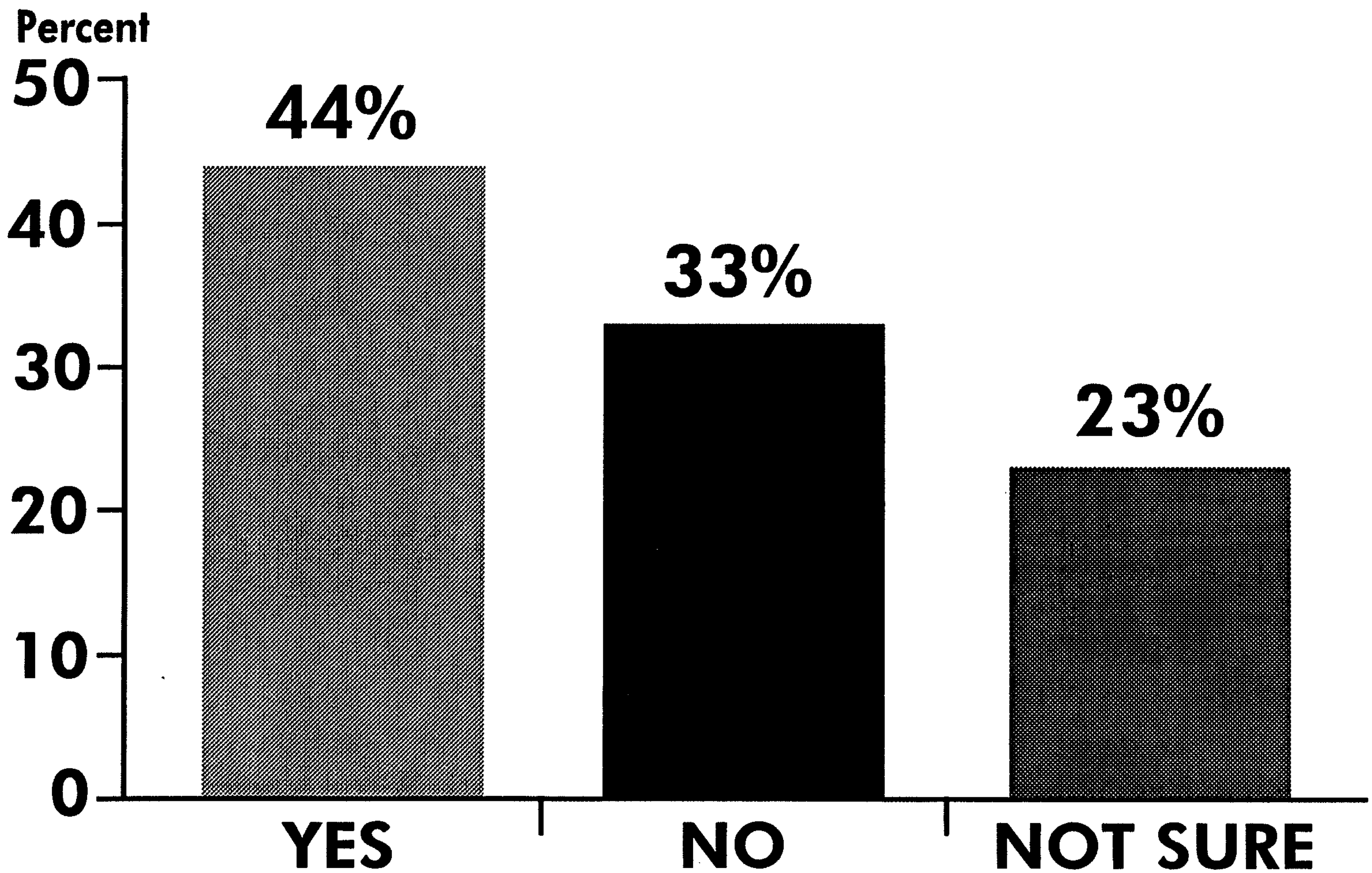
Source: Washington International Energy Group, The 1997 Electric Industry OUTLOOK

Executives Believing Nuclear Power Can Compete



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Source: Washington International Energy Group, The 1997 Electric Industry OUTLOOK

Chapter I — Economics of Individual Sites

This report has been undertaken to project the future performance of nuclear plants in the United States to determine the potential for shutdown and, hence, the need for additional capacity. As mentioned in the Background section of this report, previous studies have tended to focus on the factors that increase the cost of production, i. e., external forces. By contrast, this chapter focuses on factors that the companies can influence, in other words, internal management.

The economic performance of each facility is investigated first. To provide an analytical framework, the outlook period for the study is from 1997 to 2005. As indicated in the Background, for nearly a decade most nuclear plant owners have worked to reduce costs and improve performance. Thus, rather than concentrating on the entire history of the industry, this chapter focuses on the economic performance of each facility from 1990 to 1995, a six-year period during which there has been impressive, consistent improvement in the performance of many plants. The current paradigm is much more indicative of **expectations** than is past performance.

The most visible result of the industry turnaround is the increase in the all-plant average capacity factor. Higher capacity factors can be achieved for very little addition to O&M costs. Calculations done for this study show that the overall average capacity factor was 79.0 percent in 1995, compared with 70.8 percent in 1990, a 12 percent improvement.[20] For comparison, a study by Tim Martin & Associates reported in *Nucleonics Week* shows for 1993 to 1995 a 79.3 percent median capacity factor, and for the period 1989-91 a median capacity factor of 70.9 percent.[21] The

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[20] Output taken from *Nuclear Plant O&M Cost Data 1981-1995*, NUCOM.DBF, and Utility Data Institute, the McGraw-Hill Companies, Inc. Plant capacity taken from *Licensed Operating Reactors*, NUREG-O020, Volume 24, U.S. Nuclear Regulatory Commission.

[21] "Data Shows U.S. Nuclear Costs Dropping as Safety Improves," *Nucleonics Week*, The McGraw-Hill Companies, Inc., July 11, 1996, p. 5.

U.S. NRC reported a capacity factor of 79.6 percent using net maximum dependable capacity (MDC) in 1995.[22]

Although capacity factors for nuclear sites remain lower than for the average fossil plant, especially compared with some of the best performing plants, the importance of capacity factors cannot be overstated. According to the Energy Information Administration (EIA) study cited previously, average non-fuel O&M costs for all units (measured by $/kW) have been fairly stable for about the last decade. *Nucleonics Week,* in the foregoing article, provided a somewhat different perspective, showing that when put on a constant dollar basis, production costs in $/kW decreased from the 1990-1992 to 1993-1995 periods.

Regardless of whether total production costs have remained stable or decreased, when put on an output basis ($/kWh) EIA shows a decrease each year since 1993. The reason is the much higher output per plant. Total nuclear production in the United States increased by five percent between 1993 and 1994 and another five percent between 1994 and 1995. This occurred despite the fact that only one new plant was brought on line during these two years.[23] Nuclear generated electricity production as a percent of total U.S. generation was the highest ever in 1995, at 22.5 percent.[24] In short, the industry produced enough additional electricity from existing plants to displace about 700 billion cubic feet of natural gas that might otherwise have been needed, a figure that is 20 percent of the approximately 3,500 bcf used in electricity generation in 1995.[25]

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[22] *Licensed Operating Reactors*, NUREG-0020, Vol. 24. U.S. Nuclear Regulatory Commission.

[23] *Information Digest*, NUREG-1350, Volume 7, U.S. Nuclear Regulatory Commission, March 1995

[24] *U.S. Nuclear Plant Statistics*, UDI-2014-96, Utility Data Institute, McGraw-Hill Companies, Inc., June 1996, p. 1.

[25] Assuming the use of advanced combined cycle facilities with a heat rate of 7000 btu/kWh.

O&M Costs and Capacity Factors—Current Results and Recent Trends

In this section, we focus on non-fuel O&M costs per kWh and capacity factors, due to the importance of these two factors in indicating economic performance. The two measures are related, but all other factors being equal, the higher the capacity factor, the lower the cost per unit of production. The findings of the report relate to the cost per unit of production. The reason for selecting non-fuel O&M costs is that these costs are more controllable by owners and operators, and thus, are more indicative of performance. The industry efforts to improve performance and practices, reviewed in the Background, are largely directed at reducing non-fuel O&M costs. Nuclear fuel costs are much less subject to the control of the operator, especially since fuel supply is typically contracted over a multi-year period. Capacity factor is shown not because it is important by itself, but because it is the primary reason for changes in cost per unit of production.

The primary source of information for this evaluation is an electronic database provided by the Utility Data Institute, called *UDI Nuclear Plant O&M Cost Data 1981-1995.*[26] The UDI data come directly from the Federal Energy Regulatory Commission, FERC Form 1, which utilities are required to provide from company records. This was supplemented by a UDI publication, and by statistics from the NRC.[27] The UDI data generally combine all nuclear units on a site into one reporting unit. This, of course, does not reveal differences among individual units located on the site. But for the vast majority of cases, all units on the site are very similar in size, manufacturer, and plant management.

This study, therefore, uses all units on the site as an analytical unit and refers to this as "a site."[28] UDI refers to all units on a site as a plant. It seems less ambiguous to term this "a site," which we have done. The database splits Indian Point 2 and Indian Point 3, near New York City,

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[26] *Nuclear Plant O&M Cost Data 1981-1995*, NUCOM.DBF, *op. cit.*

[27] "U.S. Nuclear Plant Statistics, UDI-2014-96, *op. cit.,* and "Information Digest," Volume 7, *op. cit.*

[28] In some cases, units are physically connected, share control rooms and other facilities; in other cases units are not physically connected.

because although they are on the same site, they are owned and operated by different companies. The least desirable situation with this data source is that Northeast Utilities' Millstone 1 and Millstone 2 are combined, even though they are of very different size and different nuclear steam supply system (NSSS) supplier.

With this framework, there are 71 sites in the United States, consisting of 107 individual nuclear units. Of the 110 licensed units in the United States, 3 are excluded—Tennessee Valley Authority's Watts Bar because it just obtained its operating license in 1996 and has significant operating history; TVA's Browns Ferry 1 because it has been shut down since 1985; and Browns Ferry 3 because it resumed operation in late 1995 after a number of years of outage—too late to be part of the data source.[29]

Production costs per kWh of production are extremely important because these will determine which units will be competitive over the long run. We believe that owners will compare expected production costs with anticipated market prices in assessing whether the facility will be an economic asset to the company. This will become even more important in a competitive environment where the site will be competing with many other suppliers and marketers across a wide area of the U.S. and Canada.

On the basis of our analysis, we categorized all sites based on a combination of:

- trend in non-fuel O&M costs per kWh from 1990 to 1995;
- fuel O&M costs per kWh in 1995;
- trend in capacity factor from 1990 to 1995; and
- capacity factor in 1995.

A high level of output is very important for all baseload plants, but particularly for nuclear plants because a high proportion of total operating and maintenance costs are virtually fixed compared with other generating technologies, in which fuel costs are a much larger share of costs and labor costs are much smaller. Nuclear plants by their nature are among the cheapest forms of generation when they are operating, and are by far the most expensive when they are not. Whether a plant is shut down for a

[29] The project manager for Browns Ferry at the U.S. Nuclear Regulatory Commission confirmed that Unit 1 remains in long-term shutdown.

short period for routine maintenance, for an extended period, or permanently, as long as there is nuclear fuel on-site and major safety systems are operating, nuclear plant fixed costs are quite high.

We did an initial screening of performance at all sites and found that, despite overall industry improvements, there is great variation in performance among sites. We used primarily the **trend** in non-fuel O&M cost from 1990 to 1995, and the **trend** in capacity factor from 1990 to 1995, to categorize the performance of all nuclear sites. This covers the time when the performance of many sites improved significantly and also a period long enough to include a few refueling outages that last from 30 days for the very successful sites to months for others. The trends were calculated statistically for each site for the period 1990 to 1995.[30] We show the 1995 non-fuel O&M costs and capacity factors primarily as a reference point, although the 1995 results influenced the category in which we placed some sites. The number of sites and MWE in each category are shown in Figure I-1 at the end of the chapter. Summaries of cost and capacity factor by performance group are shown in Figures I-2 and I-3. Details of individual sites in the three groups are shown in Tables A-I-1 through A-I-3 at the end of this chapter.

Estimating trends in this way evens out yearly variations in performance, refueling outages, or unforeseen incidents. **All such efforts to group according to performance contain elements of judgment and this is no exception**. However, we found three rather distinct groups.

> **Top performers group** compared with all sites, shows the trend in O&M costs down and the trend in capacity factors up and has low O&M costs, high capacity factors. There are 32 sites in this group, with total capacity of 50,689 MWE, which is 52 percent of the total of 96,853 MWE of all sites included. Two sites in this group—Summer and Point Beach—were somewhat difficult to categorize. Both had a slight upward trend in non-fuel O&M costs. However, both had low 1995 non-fuel O&M costs and the capacity factor for both improved over the period.

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[30] A least-squares regression was done separately for each of the 71 sites with years (1990 to 1995) as the independent variable and non-fuel O&M cost or capacity factor as the dependent variable. The resulting regression coefficient is used as the annual trend in the dependent variable for that site.

Good performers group has sites in which, for most, the trend is down for non-fuel O&M costs and up for capacity factors. There are 22 sites in this group with total capacity of 27,109 MWE which is 28 percent of the capacity of all sites included. **Cumulatively, 76 percent of the sites and 80 percent of the capacity are in the top two groups.** In the group of good performers, there are some mixed results. For example, Fort Calhoun had high non-fuel O&M costs in 1995, but there was a significant reduction over the 1990 to 1995 period and substantial improvement in capacity factor. LaSalle would have been placed in the top performers if only considering 1995 non-fuel O&M costs. However, it was placed in the good performers group because costs increased and capacity factors decreased over the 1990 to 1995 period.

Poor performers group has high O&M costs, low capacity factors, and the trends in the wrong direction. There are 17 sites with total capacity of 19,055 MWE, which is 20 percent of the capacity of all sites included. Sequoyah, which seems anomalous for this group, was placed here in spite of its good performance in 1995. Non-fuel O&M costs and capacity factor was erratic over the 1990 to 1995 time period and thus the trend calculation has little meaning. Its non-fuel O&M costs ranged from 0.7 cents per kWh to 2.0 and capacity factor ranged from 36 to 88 percent.

There are some apparent anomalies in these data and there are some sites where the economics are adequate but where we have not considered safety concerns. As shown in Table A-I-1 at the end of the chapter, some sites have more than 100 percent capacity factor for 1995 as a result of the way capacity factor is defined. We have chosen the measurement of capacity used by the NRC in reporting nuclear performance.[31] Nuclear plants have the capability of operating at higher levels than the MDC, resulting in the possibility of operating at more than 100 percent capacity factor. Table I-1 is a summary of the findings about trends in non-fuel O&M costs and capacity factor over the 1990 to 1995 period.

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[31] *Information Digest*, NUREG-1350, Volume 7, *op. cit.*, p. 110. Gross output is total output of the plant. NRC uses net MDC to report capacity factor which deducts in-plant use of electrical output. We adopt this convention for this report. The UDI database uses nameplate rating which is typically about 10 percent higher than MDC.

Table I-1. Trends in Non-fuel O&M Costs and Capacity Factor, 1990-1995, and 1990, and 1995 Levels

	non-fuel O&M cents/kWh 1995	non-fuel O&M cents/kWh 1990*	capacity factor percent 1995	capacity factor percent 1990*
All Sites	1.61	1.69	79.0	70.8
Percent change from 1990 over 5 years	-4.4		11.7	
Top Perf. Group	1.05	1.43	89.4	73.4
Percent change from 1990 over 5 years	-26.6		21.9	
Good Perf. Group	1.50	1.76	80.3	70.2
Percent change from 1990 over 5 years	-14.9		14.4	
Poor Perf. group	2.66	2.10	63.1	72.4
Percent change from 1990 over 5 years	27.1		-12.9	

*Estimated from 1990 to 1995 trends.

Top Performers Group

The first notable finding is that the 32 sites in the top performing category showed a 27 percent decrease in non-fuel O&M costs over the 5-year period. The associated 22 percent improvement in capacity factor strongly indicates how capacity factor correlates with non-fuel O&M costs/kWh. This may mean that significant improvements in lowering costs can be made by sites in the other groups. The 1995 non-fuel O&M costs of these sites range from 0.6 cents to 1.5 per kWh, (see Table A-I-1 at the end of this chapter) so some sites may be able to further cut costs. Capacity factor, however, cannot improve much more for many of these sites. The lowest capacity factor in 1995 was 79 percent. Twenty-two of the 32 sites had capacity factor above 85 percent in 1995. Unless there is a major new development in refueling, average capacity factor cannot be much higher than about 95 percent, and we assume that on a sustained basis, compared with the most productive fossil fired plants, a 90 percent capacity factor should be considered optimum.

Good Performers Group

The good performers group, consisting of 22 sites, also shows notable improvement, and would be news by itself, were it not for the much greater improvements by the top performers. This group can be characterized as having a potential for further improvement, based on the recent past. But all generating sources will be scrutinized in the immediate future for cost cutting. There is more variation in performance within this group than the top group. The range in O&M costs was from 1.07 cents to 2.20 cents/kWh in 1995 (see Table A-I-2 at the end of this chapter). Non-fuel O&M costs for the group decreased 15 percent between 1990 and 1995. The capacity factor ranged from 68 to 97 percent. Capacity factor for 15 of these 22 sites was at or above the average of 79 percent for all sites in 1995. Before the late 1980s, a capacity factor of 80 percent or higher was rare for any nuclear plant.

Poor Performers Group

The 17 sites in this group are clearly vulnerable to early shutdown. For this group, non-fuel O&M costs per kWh have increased 27 percent while capacity factor has decreased by 13 percent, from 1990 to 1995. Most of these sites have been plagued by extended shutdowns for safety or operational problems. There are individual reasons for low performance for each site in this group and a more detailed analysis of the nature of their problems would shed greater light on their vulnerability to shutdown. From Table A-I-3 at the end of this chapter, it is seen that non-fuel O&M costs ranged from 0.90 to 3.89 cents/kWh in 1995. Capacity factor ranged from 17 to 89 percent in 1995. Even for this group, capacity factor of 3 sites was above the 79 percent average for all sites. Five of the sites in this group licenses expire by 2010.

This study's key conclusion is that owners and operators have the ability to improve the performance of their facilities. Therefore, any single plant may change from one performance group to another—most likely to the closest, but potentially to any, group. We are not aware of any fundamental characteristic related to size, age, location, or system vendor that is inconsistent with this finding, although it is generally believed that pressurized water reactors can operate a little less expensively than can boiling water reactors. We anticipate that most changes will move "good performer" sites into the "top performers" category. This will be a result of industry efforts to improve performance of all sites; but it should not be expected that all sites in the group will improve. The unexpected shutdown of Yankee Rowe in Massachusetts in 1991 and the recent shutdown of Connecticut Yankee are warnings. We believe it will be relatively more difficult to change from the category of "poor performers" to "good performers." Sites in the poor performers group have not shared in the overall improvements that characterize the industry.

Capital Additions

The remaining important cost in determining if a site may be economically viable is capital additions to the plant during its operating life. In some cases, these additions add several tens of millions of dollars to the plant each year. Capital additions are variable costs because there is still a choice about how and when they will be made (unless the addition is required for safety). Decisions on these investments depend on whether such costs are expected to be recovered given projected economic realities of the future. If the expectation is that they cannot be recovered over a certain number of years, a utility will be unlikely to make massive capital additions even in the current cost-plus-rate environment, let alone in a highly competitive price-driven market.

Even though nuclear sites have high initial capital costs, they also have historically required large additional capital expenditures. There are many causes. One is safety regulation. In the aftermath of the TMI accident, together with an electrical fire at one of the Browns Ferry units, costly changes to most plants were required by NRC. Another cause is faulty components, some of which did not have the performance life originally expected.[32] The biggest single and most visible capital item has been steam

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[32] An assessment of future capital costs is problematic. We obtained data for these costs from FERC Form 1 as provided by UDI. The data available are far from adequate, however, as they are missing for several plants. Moreover, the data are not provided directly. Capital additions are calculated by subtracting the previous year's total capital investments from the current year's. Also, if an owner has sold part of the plant, for example by a sale-and-lease-back program, "apparent" investment in the facility has decreased. UDI recognizes these problems and adjusts the data where there is a basis for doing so. For further

generator replacements in pressurized water reactors. However, most owners that plan to make replacements have already done so. Boiling water reactors have suffered from stress corrosion pipe cracking which was also costly to fix. The vast majority of sites have had one or more extended outages where major repairs or replacements have taken from several weeks to a few months or longer.[33]

Most utilities have been making significant efforts to avoid capital expenditures, particularly those that require external borrowing. If nuclear capital costs would require turning to the capital markets, we believe the difficulty of raising capital would push a utility to review shutdown options. This is particularly true for those units with a limited license period remaining.

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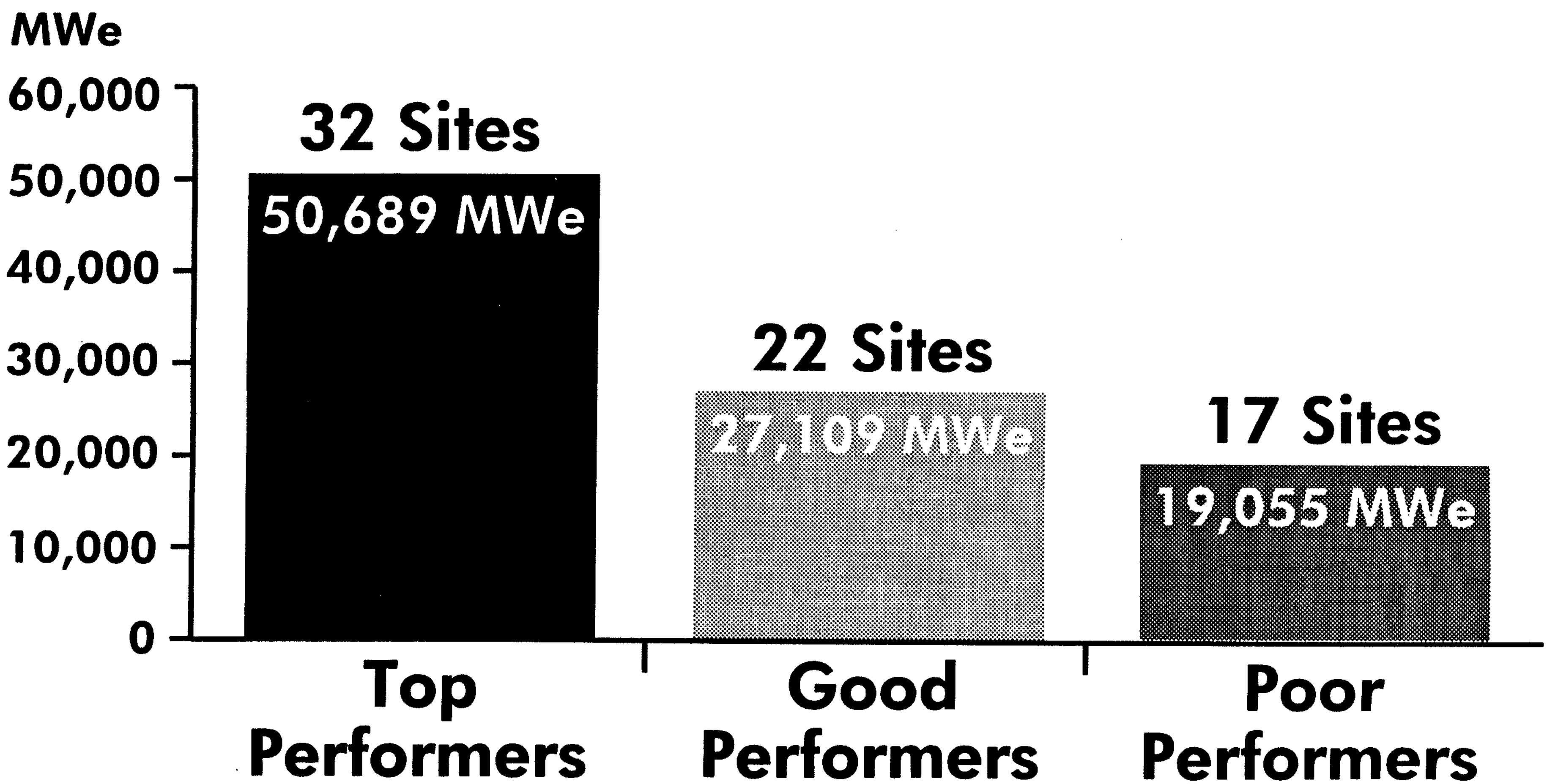
discussion, see *U.S. Nuclear Plant Statistics*, UDI-2014-96, *op. cit.*, p. 38. A fuller discussion of the data problems on capital additions is found on pp. 30 to 34, 37, and 38. Given the quality of the data, we did not analyze the impact of capital additions for determining future viability of sites, even though capital additions can be an important factor in deciding the future of a facility.

[33] *U.S. Nuclear Power Plant Operating Cost and Experience Summaries*, prepared for the U.S. Nuclear Regulatory Commission, Oak Ridge National Laboratory, March 1995.

Figure I-1

Performance Categories

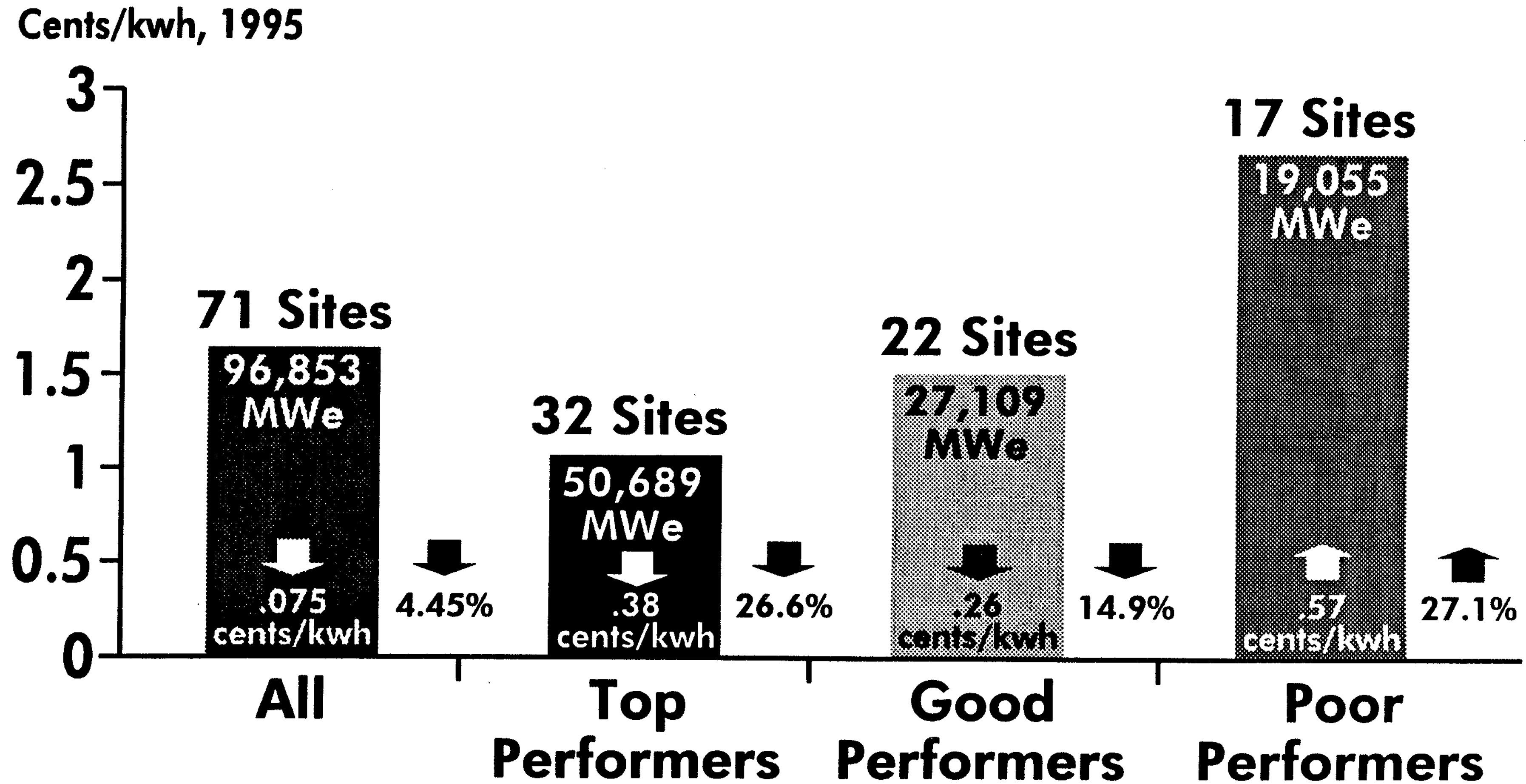


WASHINGTON INTERNATIONAL ENERGY GROUP

Cost Based On Data From UDI Nuclear Plant O&M Cost Data, 1981 - 1995
MWe From NRC Information Digest, 1995 Edition

Figure I-2

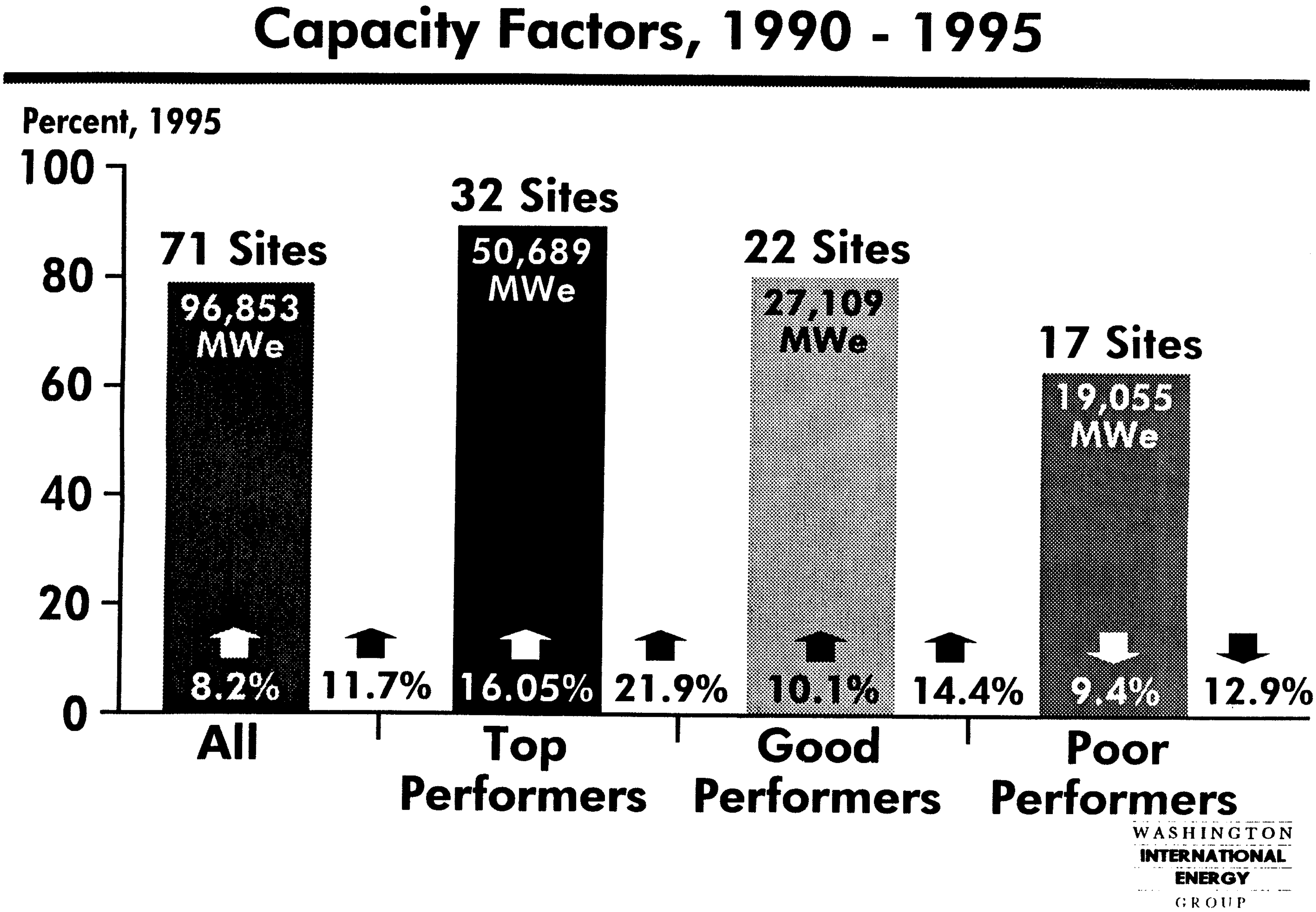
Non-Fuel O&M Costs, 1990 - 1995



WASHINGTON INTERNATIONAL ENERGY GROUP

Cost Based On Data From UDI Nuclear Plant O&M Cost Data, 1981 - 1995
MWe From NRC Information Digest, 1995 Edition

Figure I-3



Cost Based On Data From UDI Nuclear Plant O&M Cost Data, 1981 - 1995
MWe From NRC Information Digest, 1995 Edition

Table A-I-1. Nuclear Sites of Top Performers in O&M Cost and Output Performance, 1990-1995

Site	No. Units	Site MWe Net MDC	Operator	90-95 Change Capac. Factor	NOTE	1995 Capac. Factor	1990-95 Change Non-fuel O&M cost Cents/kWh	NOTE	1995 Non-fuel O&M Cost Cents/kWh	License Expiration Year	NRC Watch List
ARKANSAS ONE	2	1694	Entergy Oper.	7.5		78.6	-0.60		0.82	14, 18	
BRAIDWOOD	2	2240	Com Ed.	11.0		82.2	-0.10		0.90	26, 27	
BRUNSWICK	2	1521	CP&L	29.0		90.0	-0.44		1.23	16, 14	7/92 to 6/94
BYRON	2	2210	Com Ed.	13.0		82.0	-0.23		0.88	24, 26	
CALVERT CLIFFS	2	1675	BG&E	28.5	91-95	88.2	-0.81	91-95	1.18	14, 16	12/88 to 2/92
CATAWBA	2	2258	Duke Power	19.5		84.3	-0.10		1.13	24, 26	
COMANCHE PEAK	2	2300	TU Elec.	33.0	91-95	84.2	-0.67		0.95	30, 33	
CRYSTAL RIVER	1	818	Flor. Pwr Corp.	35.5		101.5	-0.93		1.28	16	
DAVIS BESSE	1	868	Toledo Edison	15.5	91-95	100.8	-0.66	91-95	1.04	17	
HATCH	2	1506	So. Nuc. Oper.	7.5		87.3	-0.28		1.27	14, 18	
KEWAUNEE	1	511	Wisc. Pub. Ser.	0.5		84.7	-0.35		1.19	13	
LIMERICK	2	2110	PECO Energy	18.0		89.5	-0.41		1.01	24, 29	
MAINE YANKEE*	1	860	Maine Yankee At.	20.0	90-94	88.0	-0.40	90-94	0.73	08	
MCGUIRE	2	2258	Duke Power	21.0		90.8	-0.41		0.90	21, 23	
MONTICELLO*	1	536	Northern States	5.0		101.3	-0.15		0.98	10	
NINE MILE POINT 1*	1	565	Niagara Mohawk	56.5	91-95	87.0	-0.97	91-95	1.39	09	7/88 to 6/91
NORTH ANNA	2	1787	VEPCO	6.0		88.6	-0.21		0.67	18, 20	
OCONEE	3	2538	Duke Power	-2.0		89.1	0.15		0.97	13, 13, 14	
PALO VERDE	3	3663	APS	10.0		84.1	-0.45		1.14	24, 25, 27	
PEACH BOTTOM	2	2128	PECO Energy	23.5		88.3	-0.72		1.31	13, 14	12/87 to 6/89
POINT BEACH	2	970	Wisc. Elec. Pwr.	1.0		84.5	0.22		1.02	13	
PRAIRIE ISLAND	2	1125	Northern States	8.0		94.5	-0.20		0.84	14	
ROBINSON TWO*	1	683	CP&L	21.5		86.1	-0.70		1.38	10	
SAN ONOFRE	2	2150	SCE	7.0		98.2	-0.51		1.02	13, 13	
SEABROOK	1	1150	N. Atlan. Energy	7.5		83.2	-0.27		1.17	26	
SOUTH TEXAS	2	2502	HL&P	11.0	excl. 93	87.7	0.12	excl. 93	1.08	27, 28	6/93 to 2/95
SUMMER	1	885	South Car. E&G	6.0		97.4	0.03		1.00	22	
SURRY	2	1562	VEPCO	3.0		80.3	-0.01		1.03	12, 13	6/89 to 6/90
THREE MILE ISLAND	1	786	GPU Nuclear	15.0		92.8	-0.06		1.45	14	
TURKEY POINT 3&4	2	1332	Florida Power	28.0	excl. 91	94.3	-1.31	excl. 91	1.25	12, 13	12/87 to 2/90

CONTINUED ON NEXT PAGE

Table A-I-1. Nuclear Sites of Top Performers in O&M Cost and Output Performance, 1990-1995, (continued)

Site	No. Units	Site MWe Net MDC	Operator	90-95 Change Capac. Factor	NOTE	1995 Capac. Factor	1990-95 Change Non-fuel O&M cost Cents/kWh	NOTE	1995 Non-fuel O&M Cost Cents/kWh	License Expiration Year	NRC Watch List
VOGTLE	2	2338	So. Nuc. Oper.	21.0		93.5	-0.48		0.63	27, 29	
WOLF CREEK	1	1160	WC Nuc. Oper.	26.0		99.0	-0.23		0.78	25	
Number of Sites	32										
Number of Units	55										
Total MWe		50689									
Average MWe		1448				89.4			1.05		
*License expires			5-year change			16.0			-0.38		
by 2010.			1990 estimate			73.4			1.43		
			percent change			21.9			-26.58		

NOTE: For this table and all tables showing site cost and output performance, where a site had very high or low results for one year compared with other years, the unusual year is excluded from the analysis. The exception is Browns Ferry, where both 1990 and 1991 were exclu 1992 was Unit 2's first full year of operation after an extended shutdown.

Table A-I-2. Nuclear Sites of Good Performers in O&M Cost and Output Performance, 1990-1995

Site	No. Units	Site MWe Net MDC	Operator	90-95 Change Capac. Factor	NOTE	1995 Capac. Factor	1990-95 Change Non-fuel O&M cost Cents/kWh	NOTE	1995 Non-fuel O&M Cost Cents/kWh	License Expiratic Year	NRC Watch List
BEAVER VALLEY	2	1630	Duquesne	8.5		80.6	-0.15		1.41	16, 27	
CALLAWAY	1	1115	Union Elec.	2.0		79.9	0.09		1.17	24	
CLINTON	1	930	Illinois Power	31.0		74.9	-1.40		1.58	26	
DC COOK	2	2060	Ind/Mich Power	4.5		77.6	0.05		1.39	14	
DIABLO CANYON	2	2160	PG&E	0.5		86.0	0.21		1.41	21, 25	
DUANE ARNOLD	1	515	IES Utilities	10.5		82.7	-0.07		1.96	14	
FARLEY	2	1634	So. Nuc. Oper.	-2.5		75.7	-0.03		1.26	17, 21	
FITZPATRICK	1	774	NYPA	13.0		71.2	-0.61		1.68	14	2/92 to 1/94
FORT CALHOUN	1	478	OPPD	27.0		80.2	-1.06		2.20	13	7/88 to 6/89
GINNA*	1	470	Roch. G&E	2.0		88.3	-0.16		1.62	09	
GRAND GULF	1	1143	Entergy Oper.	6.0		79.9	-0.04		1.42	22	
HARRIS	1	860	CP&L	1.5		79.2	0.42		1.38	26	
LASALLE	2	2072	Com Ed.	-6.5		79.0	0.14		1.07	'22, 23	
MILLSTONE 3	1	1137	NU	26.0		80.5	-0.56		1.42	25	1/96 to now
NINE MILE POINT 2	1	994	Niagara Mohawk	38.0		83.3	-1.36		1.65	26	12/88 to 6/91
PALISADES*	1	730	Consumers	15.5		75.6	-0.29		1.76	07	
RIVER BEND	1	936	Entergy Oper.	15.5		96.7	-0.46		1.51	25	
ST LUCIE	2	1678	Flor. Pwr. & Light	-0.5		74.0	-0.01		1.26	16, 23	
SUSQUEHANNA	2	2134	PP&L	2.0		83.6	0.14		1.22	22, 24	
VERMONT YANKEE	1	504	VT Yankee Nuc.	5.0		87.4	-0.02		1.87	12	
WATERFORD 3	1	1075	Entergy Oper.	-1.0		82.4	0.06		1.24	24	
ZION	2	2080	Com Ed.	25.0		67.8	-0.64		1.42	13, 13	6/91 to 2/93
Number of Sites	22										
Number of Units	30										
Total MWe		27109									
Average		1232				80.3			1.50		
*License expires by 2010			5-year change			10.1			-0.26		
			1990 estimate			70.2			1.76		
			percent change			14.4			-14.92		

Table A-I-3. Nuclear Sites of Poor Performers in O&M Cost and Output Performance, 1990-1995

Site	No. Units	Site MWe Net MDC	Operator	90-95 Change Capac. Factor	NOTE	1995 Capac. Factor	1990-95 Change Non-fuel O&M cost Cents/kWh	NOTE	1995 Non-fuel O&M Cost Cents/kWh	License Expiration Year	NRC Watch List
BROWNS FERRY	1	1065	TVA	1.5	92-95	40.2	-0.39	92-95	1.29	13, 14, 16	12/87 to now
BIG ROCK POINT*	1	67	Consumers	9.0		87.9	0.10		3.89	00	
CONN YANKEE*	1	560	NU	-2.0	91-95	74.7	0.02	91-95	2.47	07	
COOPER	1	764	NPPD	-32.5		61.7	1.74		2.26	14	
DRESDEN*	2	1545	Com Ed.	-19.0		39.3	1.91		3.79	06, 11	2/92 to now
FERMI	1	1085	Det Ed	-12.5	excl. 94	53.6	-0.31	excl. 94	2.10	25	12/87 to 6/89
HOPE CREEK	1	1031	PSE&G	-6.5		78.0	0.60		1.67	26	
INDIAN POINT THREE	1	965	NYPA	-73.0	excl. 94	17.4	0.91	excl. 94	7.42	15	6/93 to now
INDIAN POINT TWO	1	951	Con Ed.	13.0		58.3	-0.44		2.88	13	
MILLSTONE 1&2*	2	1514	NU	-8.5		53.7	0.91		3.04	10, 15	1/96 to now
OYSTER CREEK*	1	619	GPU Nuc.	3.0	excl. 95	66.9	0.22	excl. 95	3.60	09	
PERRY	1	1166	Clev. Electric	-6.0		89.1	0.90		1.47	26	
PILGRIM	1	670	Boston Ed.	5.0		76.4	0.53		2.68	12	12/87 to 6/89
QUAD CITIES	2	1538	Com Ed.	-17.0		62.0	1.28		2.14	12, 12	
SALEM	2	2212	PSE&G	-8.0	90-94	58.3	0.98	90-94	2.10	16, 20	
SEQUOYAH	2	2217	TVA	-19.5		81.6	0.75		0.90	20, 21	12/87 to 6/89
WNP 2	1	1086	WPPSS	14.0		73.0	-0.04		1.57	23	
Number of Sites	17										
Number of Units	22										
Total MWe		19055									
Average		1121				63.1			2.66		
*License expires by 2010.			5-year change			-9.4			0.57		
			1990 estimate			72.4			2.10		
			percent change			-12.9			27.09		

Chapter II—Non-Economic Drivers—Individual Sites

This phase of the report investigates other issues that may influence decisions as to whether to shut down nuclear facilities. These are:

- the NRC Watch List and other indicators of regulatory problems;
- availability of waste storage on-site;
- license renewal;
- decommissioning requirements and related regulatory requirements;
- stranded costs; and
- public attitudes.

None of these dynamics alone would appear to lead management to shutdown a facility. However, when combined with poor performance, we believe these factors, especially the lack of waste storage, could influence management decisions as to whether to shut down a facility.

Trends in Safety Performance as Rated by NRC and Others

We had expected safety to be an important determinant of nuclear site viability over the next several years. However, after review, there do not seem to be significant differences among the three performance groups in Chapter I. Two measures of safety performance, NRC's SALP (Systematic Analysis of Licensee Performance) scores and NRC's Watch List, are intended to inform licensees of low safety performance. Neither evaluation is intended as a safety ranking, but we had expected that some relationship would be shown between these safety evaluations and our economic performance groups, and there does not seem to be any strong association. Several sites that are top performers have been on the NRC Watch List, as have plants in the other two categories. A larger proportion of sites in the low group have been on the NRC Watch List; however, several have not. It is difficult to see how some plants get on the Watch List, and how others avoid getting on the List, based on other performance measures such as SALP scores. Indeed, the NRC has been criticized for not making public the procedure for selecting plants for the Watch List, implying that its criteria may be arbitrary. The primary evidence for this statement is the Northeast Utilities' Millstone units, which received low SALP scores over the years, but only in 1996 were placed on the Watch List. Figure II-1 at the end of the chapter shows the number of sites in each group that have been on the Watch List.

Public Citizen, an anti nuclear organization, publishes occasional reports entitled "Nuclear Lemons" showing for a number of NRC performance measures—plus operating and maintenance costs—which plants are the worst overall. There is some commonality between this year's "lemons" and the category of poor performers identified in Chapter I, see Appendix Table 1 at the end of the report.

In addition to NRC, the Institute for Nuclear Power Operations (INPO), an industry group, performs independent safety evaluations of individual plants. Its evaluations are not made public. Thus, it is of value only to its members and cannot be considered in this report.

It is not fruitful to give much weight to "lemons" or the Watch List in searching for sites that are vulnerable to shutdown prematurely. We believe the economic performance trends we have identified are much more important. However, the licensee's relationship to NRC is important. If the agency has ordered a plant to shut down, or is requiring plant modifications or major evaluations, it is costly in time and attention to the licensee, and diverting resources that might otherwise improve economic performance. It is thus important to keep abreast of NRC interactions with licensees to know which plants are being closely scrutinized. The negative impact on stock prices, embarrassment, loss of credibility, and hard costs (for replacement power, upgrades, etc.) associated with NRC review may result in a decision to not reopen units. And, of course, negative public responses that erode confidence can be devastating and may in themselves encourage a utility to close a plant.

Developments That Can Impact the Analysis

Reliance on published data sources for the foregoing evaluations does not take into account late-breaking developments at individual sites. Any site potentially can be shut down for a long period, even posing the question about whether it should be permanently shut down. This is easier to predict for some sites than others. In 1996, a dramatic example occurred when NRC ordered the shutdown of all sites operated by Northeast Utilities, with the exception of Seabrook. The future of these sites is still unknown except for Connecticut Yankee, which the owners decided to permanently shut down on December 4, 1996. For the quantitative analysis of this report, these units are placed in the categories that the data indicate. However, on the basis of NRC reports and actions regarding these sites, we believe that all of the Northeast Utilities sites except for Seabrook are now vulnerable to shutdown.

Millstone Unit 3 was the biggest surprise. It is a newer, larger facility than Units 1 and 2 or Connecticut Yankee. The data derived from Unit 3's performance placed it in our category of **good performers**, with its non-fuel cost per kWh trending downward and capacity factor trending upward. Although the reason for its shutdown was safety concerns, the NRC findings can be extended to maintenance in general, which does affect the economics and safety of operations.[34] Lower cost of production seems to have been achieved partly at the expense of performing needed repairs and maintenance. The company, according to a statement from the plant director, focused on the day-to-day task of keeping its plants on line and avoiding costly shutdowns. As the backlog of repairs and maintenance grew, some maintenance came to be regarded casually.

The Impact of the Department of Energy's Nuclear Waste Program on Existing Nuclear Power Plants

We have thoroughly reviewed the Department of Energy's (DOE) program to construct a permanent repository at Yucca Mountain to

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[34] "A-Plant Managers Try Attitude Adjustment, Hundreds of Standards Fell, N.R.C. Says," *The New York Times*, September 3, 1996, p. B1, and "New Report Blames NU's Top Management for Millstone Nuclear Plant Problems, *Electric Power Daily*, January 2, 1997, Inc. p. 3.

dispose of commercial nuclear fuel. Our analysis concludes that the failure of DOE to take title of spent fuel by January 31, 1998, as required by statute and contract, is a major irritant to electric utilities that own and operate nuclear power plants. However, we have concluded that the waste situation by itself will not lead a utility to shut down a plant that is in either the top performers or good performers category. Owners who are either running out of on-site storage for waste, or need to apply for license renewal, combined with having performance problems, may be inclined to close down a facility rather than take on the politically contentious fight in their state that usually accompanies a request to add new waste storage facilities at a site. Some states require formal proceedings before their respective commissions and agreement that there is a need for additional facilities before new storage facilities can be added. A formal proceeding quickly polarizes the situation and raises all the controversial issues surrounding each plant and nuclear power in general. Some states do not require such a formal proceeding.

A paper presented by Eileen M. Supko of Energy Resources International at the Nuclear Waste Issues Forum in May of 1995 identified the universe of sites and reactors that could be affected by running out of storage. The paper also detailed the costs that are imposed by adding new storage facilities and stated that NRC has issued six site specific licenses for utilities to add dry spent fuel storage facilities at reactor sites, but that one utility is operating under a general license.

The paper estimated that 26 reactors will require additional storage in 1998, the date by which DOE was supposed to begin taking the waste based on contracts it signed with owners of nuclear facilities. An additional 39 to 63 reactors will have to expand on-site storage capacity at some point. Approximately 90 reactors will require additional storage if DOE has not begun to accept waste by 2010. It should be noted that there are different estimates with respect to the number of sites and units that will require additional storage. Most importantly, the paper estimated that life cycle costs of adding an additional 500 metric tons uranium (MTU) capacity at on-site storage facilities are approximately $34 to $50 million. There are also costs associated with storage of spent fuel after the reactor is shut down. The life cycle costs include up-front, incremental, operating and decommissioning costs.[35] The costs are the reason we have reached our conclusions regarding the impact of waste situations on existing facilities. If plants in either of the top two categories are generating significant revenues, $50 million does not figure to be prohibitive to maintain an expensive asset. This is the primary reason we have reached our conclusion.

Regulation—the Developing Issues

License Expiration/License Renewal

There is little evidence to show that many facility owners will proceed with license renewal. The Washington International Energy Group's annual survey shows, at most, ambivalence toward license renewal—47 percent in 1994, 39 percent in 1995, 41 percent in 1996, and 40 percent in 1997 expressed the belief that license renewal would go forward.[36] See Figure II-2 at the end of the chapter.

The first license to expire among the facilities still in operation is that of Big Rock Point in 2000. By 2007, original licenses at four sites will expire, including Big Rock Point. As shown in Tables A-I-1 through A-I-3 at the end of Chapter I, by 2010 licenses at an additional seven sites will expire by 2010. Figure II-3 at the end of this chapter shows the location of these sites. These 11 sites have capacity of 8149 MWE or 8 percent of the total MWE. These older facilities are smaller than more recent facilities. Twenty-five more sites are subject to license expiration by 2015, with a total MWE of capacity of 33,376 MWE or about 35 percent of total nuclear MWE. Thus, about half of the sites' licenses will expire by 2015.

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[35] In order to review the methodology utilized to forecast when reactors may require additional storage and the costs of doing so, see, "Utility at Reactor Spent Fuel Storage Requirements and Costs, presented at the Nuclear Waste Issues Forum, sponsored by the Nuclear Waste Program Office, National Association of Regulatory Utility Commissioners, (NARUC) Eileen M. Supko, Energy Resources International, May 1995.

[36] *The 1995 Electric Industry Outlook, The 1996 Electric Industry Outlook,* and unpublished response to the survey for *The 1997 Electric Industry Outlook,* Washington International Energy Group.

The Atomic Energy Act provides that a license to operate a nuclear power plant may be issued for up to a maximum of 40 years and that the license may be renewed. To date, no applications have been submitted to NRC although a number of utilities are preparing to do so. By current NRC regulations, licenses may be renewed for up to an additional 20 years. Although there is some controversy about the reasons for a 40-year license, most analysts agree that the restriction was not safety related. One explanation is that the Congress in 1954 was concerned with the antitrust implications of allowing large utilities to construct large facilities and obtain monopolistic advantages over smaller utilities. By the time license renewal became an important issue, NRC's concerns were directed at safety. NRC wishes to ensure that the structures and systems that have not been reviewed for long periods of time, for example, some containment structures, are still capable of performing their safety functions.

In 1985, NRC began work that would lead to rulemaking for license renewal. This was a lengthy and contentious process of conducting studies and technical and legal debates on what should be required for license renewal. It was to be a joint undertaking with industry, the Nuclear Energy Institute, and its predecessor organization, participating at various levels. DOE participated by selecting two sites as pilot projects, Monticello in Minnesota as a boiling water reactor and Yankee Rowe in Massachusetts as a pressurized water reactor. DOE supported research on license renewal for these two sites.

An extensive debate ensued, internal to NRC and with the industry, over what was required for license renewal ranging from (1) "a site that has a history of safe operation should receive a license to continue" to (2) "the site should be shut down if it cannot show NRC that it can be operated safely in the future according to the most recent requirements for licensing a new site." An initial regulation was completed in 1991, which could be characterized as closer to the more stringent end of the spectrum. It called for an extensive review of structures, systems, and components to confirm that they are likely to function for safe operation during the period of the renewed license. Little credit was given for a site's past record of safe operation.

Two events occurred that prompted questions on the future of license renewal:

- the owners of both pilot sites dropped out, and
- the industry made clear to NRC that the license renewal regulation was too complex to attract any license renewal applications.[37]

The owners of Yankee Rowe dropped out because the site was permanently shut down due to questions of pressure vessel safety. Northern States Power, the owner of Monticello, bowed out because of general uncertainty of proceeding and it was embroiled in a major proceeding with the state about being allowed to place additional waste storage facilities on-site at its Prairie Island nuclear facility. Northern States Power indicated it had terminated the pilot program partly because of its uncertainty in working with NRC to resolve regulatory issues.

A new license renewal regulation was enacted in 1995. Credit can now be taken for plant structures, systems, components, maintenance, and operations that have received periodic inspections. The regulation focuses on the management of the adverse effects of aging during the extended period of operation.

The industry has expressed greater satisfaction with the current regulation. However, no owner has announced that it plans to proceed with license renewal. The current approach of the industry is to work through owners' groups. Baltimore Gas and Electric Company (BGE) is developing a specific approach for the license renewal application for its Calvert Cliffs plants, which have licenses expiring in 2014 and 2016. BGE has submitted several technical reports but it has not given any dates for when an application may be submitted. The Westinghouse Owners Group and the Combustion Engineering (CE) Owners Group each plan a generic application.

Attempting to determine if any site owner will renew its operating license is difficult. Furthermore, there remains considerable uncertainty on just how long the license renewal process will require, starting from a decision by the

[37] *License Renewal: The Utility Decision Making Perspective*, OPP-93-01, Office of Policy Planning, U.S. Nuclear Regulatory Commission, February 1993.

licensee to initiate license renewal to the final NRC action. Official releases from NRC indicate that the licensee may require 3 to 5 years for application preparation. An application must be filed 5 years prior to expiration of the original license. A licensee starting without any technical analyses completed before a decision to go forward would add a few years to the process. Some NRC officials expect that the entire time span required for license renewal will be about 15 years, with the time required likely to vary depending on the past safety record of the plant. If the license expires during the 5-year review process, it is probable that the plant would be allowed to continue in operation under a provision called "timely filing."[38]

Decommissioning and Related Competitiveness Concerns

Nuclear facilities are much more costly to decommission than are other power generating facilities. NRC has by regulation established requirements for decontamination and decommissioning to remove the radiological risk. For radiological decommissioning alone, NRC requires that each plant accumulate $130 to $160 million.[39] A licensee may use its own estimate if it believes NRC's estimate is too low, and most are planning for higher costs. To provide reasonable assurance that funds will be available to decommission nuclear facilities when they are no longer productive assets, regulations also provide for paying into a decommissioning fund. The fund is to be designed so that decommissioning costs can be fully covered through periodic payments and accrued earnings.

Requirements for license renewal, decommissioning, and safety have added to regulatory costs. Modifications to the decommissioning regulations continue to be made. Currently, the regulations only require that the radiological danger be controlled so that there can be unrestricted public access to the site. Others argue that licensees should also remove many of the nonradiological structures so that the entire site can be restored to some unspecified "greenfield" level.

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[38] Administrative Procedure Act, 5 USC 558 and Code of Federal Regulations, 10 CFR 2.109.

[39] Code of Federal Regulation, 10 CFR 50.75. The actual regulation is in terms of a formula to calculate the cost for a specific reactor.

Although not strictly a part of decommissioning, the lack of resolution of the disposition of high and low level waste has forced licensees to include the cost of temporary handling of these materials when deciding on the timing of decommissioning. If holding these materials on-site requires additional facilities, these will have to be decontaminated and perhaps eventually disposed at an off-site waste facility.

NRC Concern about the Impact of Competition on Nuclear Utilities

NRC has new concerns with discharging its responsibilities with respect to decommissioning now that competitive markets and competition are moving forward. The current Commissioners, especially the Chairman, are likely to keep this an active area of concern. Two general areas will receive attention. One is to add regulatory requirements ensuring that funds will be available when needed to meet license requirements. The other is to review changes in the ownership of a nuclear facility—NRC seeks assurance that there is no question as to who all the licensees of a facility are. Thus reviewing organizational changes from a safety and financial capability viewpoint will receive more attention. Antitrust reviews of ownership changes will be more thorough.

The basis for NRC's current financial regulations is the presumption that all licensees are either investor-owned utilities (IOUs) which are regulated at the state and federal levels, or publicly owned utilities (POUs). For both IOUs and POUs, it is NRC's position that the current system of economic regulation provides reasonable assurance that licensees will be financially able to meet NRC's requirements for decommissioning. Rate regulators almost always accept without question expenditures to meet NRC requirements, viewing them as prudent expenditures. Therefore, IOU licensees can recover these costs through rates. The concern is that in the move to competitive markets, some licensees may not have the status of a regulated utility. Thus, NRC's presumption may no longer be valid and there would no longer be sufficient assurance that funds are available for safe operations and funding for decommissioning.

By far, the biggest potential change relates to decommissioning funding. Currently, licensees that are IOUs are required to pay into a decommissioning fund which, over the remaining operating life of the site, will provide funds to meet NRC decommissioning requirements. In all cases, these licensees are following the option of periodically putting money into an "external sinking fund" over the remaining operating life of the nuclear site. Public Utility Commissions (PUCs) have always considered this to be a prudent expense and have allowed it to be recovered in rates. POUs are allowed greater latitude on the basis that funds are more likely to be available from general revenue sources. NRC is reviewing whether the current requirements are sufficient to ensure funding in a competitive market.

Implications for continuing or shutting down specific reactors are many, some of which are not perceived at this time. The most important one is the possibility of having to provide decommissioning funding assurance from external sources. This means that several hundred million dollars will have to be assured by one or more financial devices. Whether financial sureties or other mechanisms of this magnitude can be arranged is yet to be determined. The net effect is likely to heighten the dilemma of several nuclear site owners of when to permanently shut down nuclear sites.

Changing Regulatory Requirements

The industry has been subject to a number of unanticipated requirements from NRC over the years. Many believe they are the principal cause of capital cost increases during the 1980s. New requirements have diminished, but not disappeared. Recently, NRC ordered nuclear operators to submit comprehensive information on their efforts to maintain accurate design documents of the reactor facility. At several plants in the past several months NRC inspectors have found discrepancies between the original design and current configurations. In some instances these deficiencies could "adversely affect the operability of required safety systems."[40]

Some regulatory changes benefit licensees by allowing more options in meeting safety requirements. One NRC analyst credits a significant part of the reduction in refueling outage duration to changes in regulations to allow more on-line maintenance. The refueling outage now can be devoted

[40] Press Release, U.S. Nuclear Regulatory Commission. A letter was sent to all licensees on October 9, 1996.

more to the single purpose of refueling rather than to maintenance that was delayed during plant operation.

Stranded Costs

The issue of stranded costs, one of the most important concerns for the nuclear industry, will be discussed in greater detail in Chapter V. In short, states and the federal government took significant action in 1996 to develop procedures for the recovery of stranded costs. Existing systems, we believe, will set the pattern for other states. All those in place provide for substantial recovery of sunk investment costs. The Washington International Energy Group believes that most states and the federal government will provide for stranded cost recovery, even if not 100 percent of all such costs. Thus, we believe that stranded costs will not be a direct determinant in shutting down a nuclear plant.

But even if stranded costs are not recovered, shutting the plant down will do nothing for a company's exposure to stranded costs. A nuclear plant that has high operating cost or other defects may be shut down to improve company profitability. But continuing to run a facility with low operating costs could be the best choice for enhancing company profitability—even if it has large stranded costs.

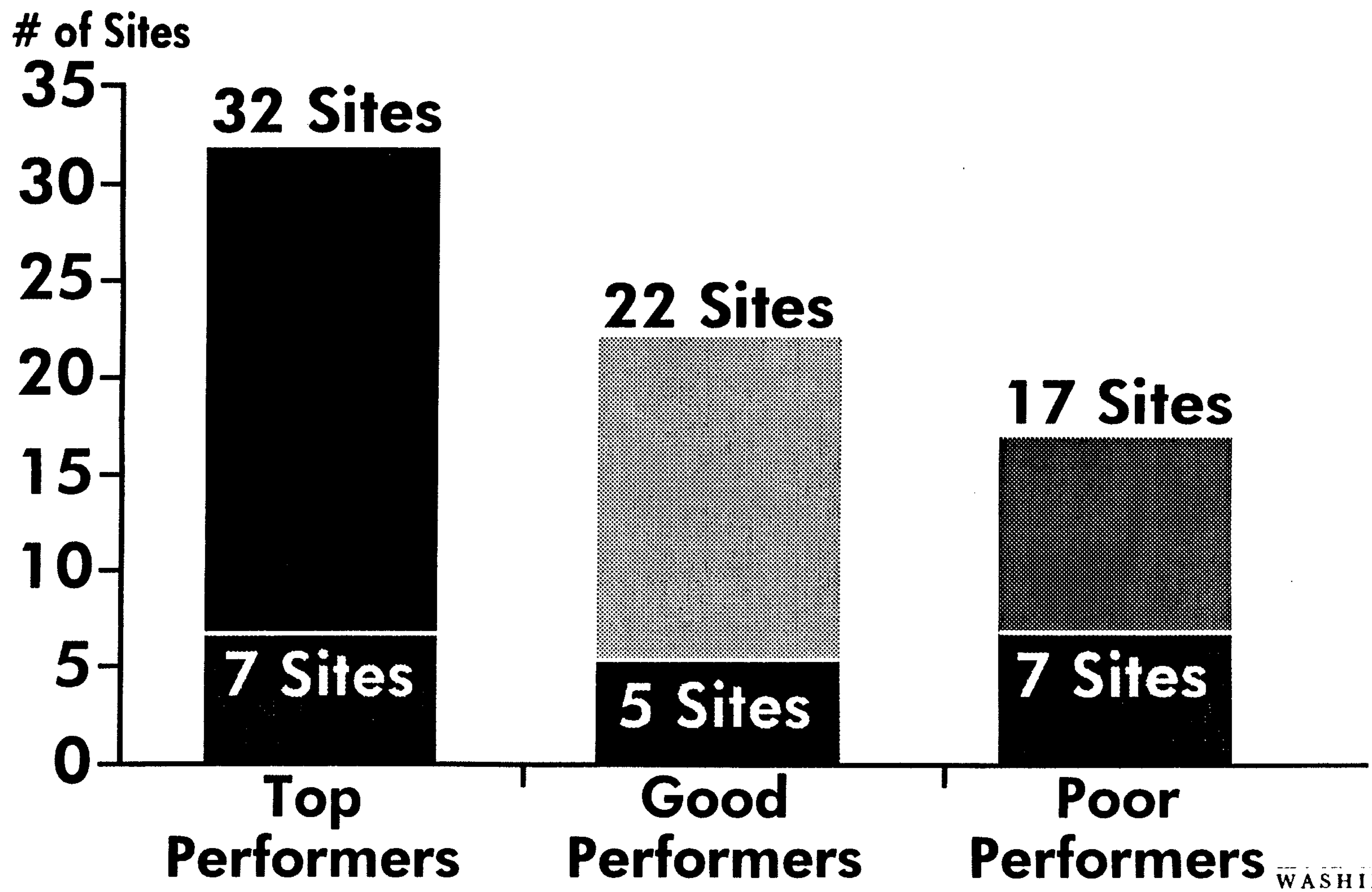
Stranded cost recovery can have an important indirect impact on continuing a plant's operation. If, for an investor-owned utility, these costs mostly relate to debt, the company has reduced ability to make needed capital expenditures, including improvements to enhance the economic performance of its nuclear facilities. This situation can eventually force a decision to shut down a low-performing nuclear plant.

Public Attitudes and Nuclear Opposition

The position of public advocacy groups is likely to be a major factor in licensees' decisions to maintain nuclear capacity. A guide to the degree of public opposition to nuclear activities is the intensity currently directed at nuclear waste facilities, both high and low level, including on-site storage. Examples are (1) the request of Northern States Power to add additional on-site storage at its Prairie Island nuclear facility, and (2) the intense opposition to the proposed Low Level Waste (LLW) facility at Ward Valley in California, and to low-level waste (LLW) storage in Nebraska. Various public advocacy groups are likely to be strongly opposed to license renewal.

Figure II-1

Sites That Have Been On NRC Watch List

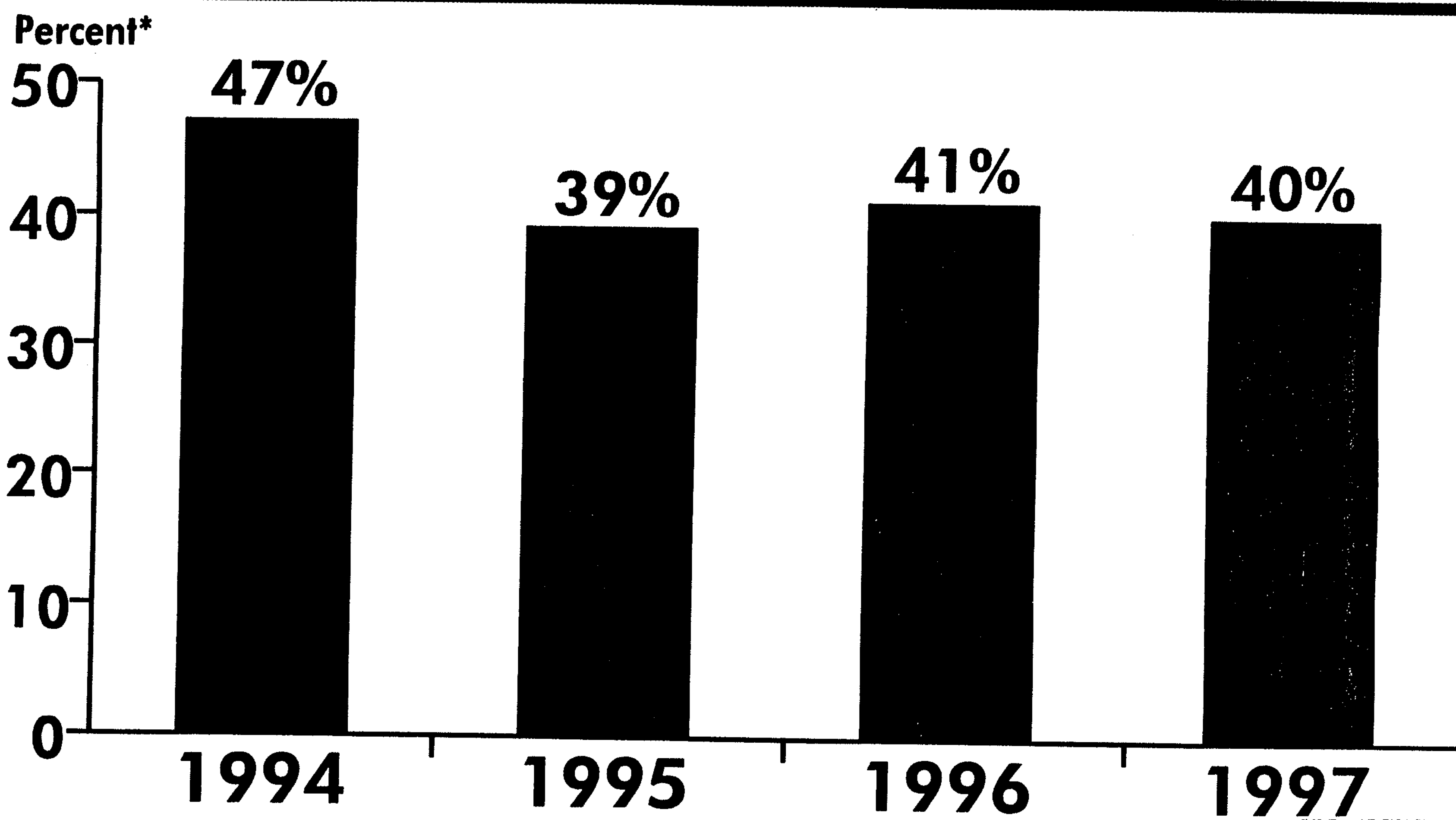


WASHINGTON INTERNATIONAL ENERGY GROUP

Source: NRC Commission Briefings

Figure II-2

Percentage Of Respondents Who Think License Renewal Will Occur

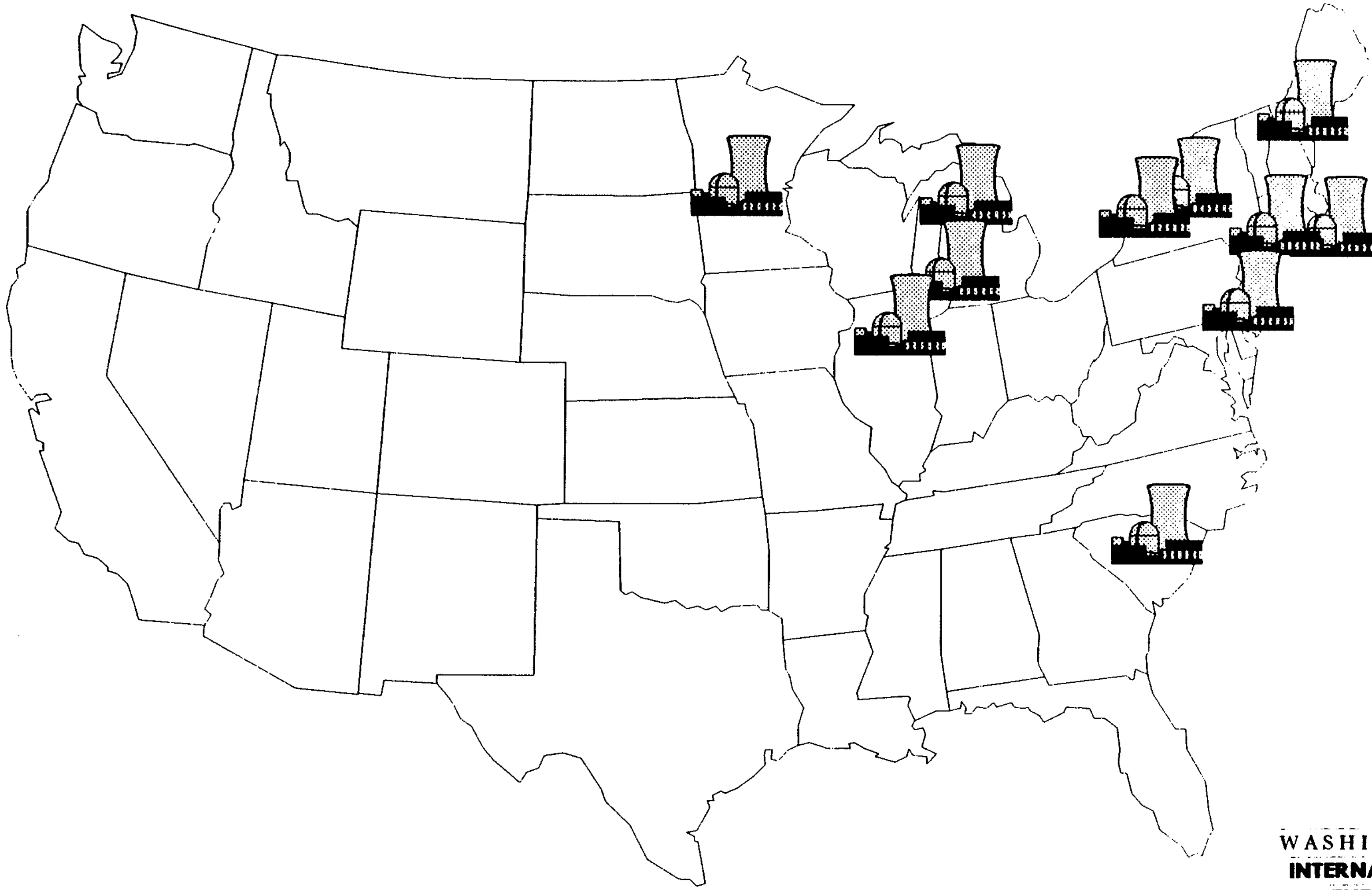


* Percentage of Respondents

Source: Washington International Energy Group, The 1995, 1996 and 1997 Electric Industry OUTLOOK's

Figure II-5

Sites With Licenses Expiring By 2010



WASHINGTON INTERNATIONAL ENERGY GROUP

Source: NRC Information Digest, 1996 Edition

CHAPTER III—COMPETITIVE ENVIRONMENT

Overview

In this chapter we make the transition from evaluating the economic performance of sites and other dynamics that affect individual sites to evaluating the market environment in which the product, electricity, will be sold. Ultimately, the future of these facilities will be determined by the markets in which they are competing. This phase of the analysis attempts to look at general trends in these markets. There is a widespread belief that competition will tend to push down prices and test the competitiveness of most existing utility assets. Nuclear plant costs, which have been declining, may have to go even lower in order to compete. The two uncertainties facing the nuclear industry are:

- what is the lowest possible sustainable price for nuclear generation consistent with continued safe operation; and
- what will be the market price for electricity?

A subsidiary question—beyond the scope of this report—is what will be the generating costs of other fuel sources, such as coal and natural gas? This analysis is not as rigorous as many site owners will perform, but is instead an attempt to project future prices in general terms to determine how sites will compete.

Evaluation of Competitive Position of Nuclear Sites at Market Prices

An important dynamic in deciding whether to continue operating a facility is the future cost of doing so. Chapter I evaluates recent trends in cost for each of the 71 nuclear sites in the U.S. This is only part of the information that an owner will require when deciding the future of nuclear assets—it is also important to know the expected revenues as determined by prices. In a highly competitive market, according to economic theory, the decision to continue running a nuclear site will be made the same way as is any other business decision, that is, to maintain it as a production unit if it is expected to make a contribution to fixed costs with all variable costs covered. But nuclear power facilities involve further considerations.

The cost structure of nuclear facilities presents special circumstances that must be considered in deciding to shut down a facility. Categorizing cost as fixed or variable is not adequate for deciding the competitiveness of a facility. The most important distinction is whether costs are sunk, in which case they have to be **paid by someone**, or future costs, in which case they can be **avoided** by a decision to discontinue operation. Past capital costs are clearly sunk costs. In keeping with the theory, facilities will be run even if sunk costs are not fully covered. Aside from whether sunk costs are considered in the decision to operate, these costs are expected to be recovered in many instances through arrangements with state and federal regulators.

If a decision is made to shut down a nuclear facility, fuel and O&M costs will cease after the facility is stabilized and decontamination/ decommissioning begun. Note that the analysis now includes both fuel and non-fuel O&M costs for comparison with market prices. Therefore, if an owner does not anticipate that average annual revenues in the future will be sufficient to cover average annual O&M costs, there is no economic reason to keep the facility in operation. In this situation, the sooner a facility can be shut down and decommissioning begun, the less cash outflow there will be. Furthermore, additional burdens of safety regulation and public opinion make it unlikely that a site would continue operation if it is expected that all fuel and O&M costs cannot be covered. For these reasons, because this report is to evaluate the vulnerability of nuclear sites to a **permanent** shutdown, fuel and O&M costs are used in the following analysis.

A decision on permanent shutdown is quite a different situation from an **economic** decision on **temporarily** operating the facility. A facility may be operated temporarily if only marginal costs are covered—for nuclear facilities this is primarily fuel costs.

The quantitative analysis that follows includes only the value of energy sales—mWh. Other marketable values are derived from electric power plants, one of the most common being capacity. Capacity is sold by one company contracting for a certain amount of capacity—megawatts—from another company over a given period, with a set of terms for the price. A major uncertainty for this study relates to the future value of capacity. At today's low prices, we do not expect capacity to have substantial market value. This could change and generate the equivalent of a few dollars per mWh.

Another potential marketable service is to sell electricity on the recently established electricity futures market. In this case, any price in excess of marginal production cost may be attractive because futures would only be sold if idle capacity is anticipated at the time of delivery. Another way to enhance revenue is to shift more of the year's production to peak demand periods—the summer in most areas of the U.S.—and the winter peak. Prices are substantially higher during peak demand periods. This can be done by always planning for refueling and other planned outages in the spring and fall—the off-peak, when prices are substantially lower. To assess the potential market value of these services would require a more detailed analysis than is possible here of each company's capacity and the market in which each will operate. We can only state that other marketable values of nuclear facilities may provide a revenue cushion in some situations where fuel and O&M costs are high relative to market prices for electricity.

In Chapter I, nuclear fuel costs are excluded from O&M costs for grouping sites according to 1990 to 1995 cost and output performance because owners have limited control over nuclear fuel costs. However, in the future, power plant owners will be likely to have more control over nuclear fuel prices. Many think the impending privatization of the U.S. Enrichment Corp. (USEC) will allow site owners more flexibility in buying such services than if they were still dealing with a government-owned entity. In addition, the accelerated downblending of Russian weapons-grade high enriched uranium and the potential for burning of subsidized mixed oxide fuel, may all put downward pressure on mid- to long-term nuclear fuel prices. For 1995, nuclear fuel averaged 30 percent or nearly $6/mWh of total O&M costs of just over $19/mWh. It is difficult to project how changes in the nuclear fuel supply industry will affect prices, however, downward pressure on nuclear fuel prices can be anticipated. A significant reduction in nuclear fuel cost would make sites that are now vulnerable to shutdown more viable.

The discussion so far relates to a highly competitive situation where market price forces high cost units off a system. In a less competitive market, however, where price is at least as high as the average cost of all units owned by a company, an owner may choose to keep high cost units in operation to meet other company objectives by rolling them in.

Owners of nuclear sites will have to consider other corporate trade-offs when making decisions on plants, such as meeting air quality standards by operating a nuclear plant rather than investing new capital in an old, amortized but possibly lower-cost fossil unit. There are significant uncertainties about the cost of fossil generation in relation to implementation of the Clean Air Act Amendments (CAAA) of 1990. Implementation of the Clean Air Act could require further capital costs to reduce emissions of nitrogen oxides, sulphur dioxide, particulates, and potentially mercury. These are separate from costs that could be imposed to reduce emissions of carbon dioxide. The administartion is currently negotiating an international agreement that will address greenhouse gas emissions in the 21st century. The agreement might be achieved at a meeting in Japan in December 1997.

In short, an analysis that only looks at cost without trade-offs and other considerations is not complete; **yet cost remains the single most important variable, especially in a competitive marketplace.**

Source of Price Projections

Properly estmating expected prices from now until 2005 presents a dilemma. One approach is to rely on forecasts that project prices on the basis of the current regulatory regime that governs the industry. This is exemplified by studies performed by the Energy Information Administration in its *Annual Energy Outlook.* The EIA is restricted in the assumptions it can make regarding the market structure of the future. However, in its *1997 Outlook*, EIA adjusts to this restriction by projecting that electricity prices will fall due to cost cutting by electric utilities in preparation for the evolving competition.[41] The Washington International

[41] *Annual Energy Outlook 1997*, DOE/EIA -0383(97) Energy Information Administration, December 1996 p. 50. EIA has not included a formal analysis of the impacts of competition on prices, however, its forecasts project cost reductions that are driven by the industry's expectations of lower prices.

Energy Group does not believe that the current system of rate regulation will continue. The most recent annual survey of the industry finds that 86 percent of the respondents believe that retail choice is inevitable.[42]

Therefore, we take another approach to price forecasting. Our forecast proceeds on there being no historical basis for projecting electricity prices in a competitive environment. Models of a competitive market are utilized and future prices simulated by these models. By the nature of this approach, there is no track record to test the validity of such models. Their value is that, if reasonably constructed, they provide a logical and consistent basis for anticipating prices.

Not only is there a lack of experience with competitive electricity markets for projections, but there is extensive controversy on just how rapidly full competition will develop. The Washington International Energy Group believes that the pace will be quite rapid. But what emerges will not be a neat textbook case of open competition, rather there will be many experiences and models utilized to accommodate varying market circumstances. For this reason and others, a great measure of caution is in order in interpreting specific conclusions derived from the analysis.

IREMM, the model we have used, provides price and other projections on a regional basis from 1997 to 2015.[43] The model projects rising prices throughout the period. As the industry moves into competition, it is widely assumed that prices will fall due to overcapacity and the innovations that competition will facilitate. This is the view of the Washington International Energy Group backed by our survey results and the forecasts of the Energy Information Administration. Therefore, to be as conservative as possible, we have chosen to use the 1997 prices from the IREMM model for our price estimates and hold them constant through 2005. This should maintain as many sites as possible as being competitive. Admittedly, we have made a judgment with which others may disagree, especially if they project large declines in electricity prices. Models are not good tools for measuring volatility and other short-term swings. But it is

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[42] *1997 Electric Industry Outlook*, Washington International Energy Group, p. 5.

[43] The simulation model was developed by IREMM, Inc., and is described in the Technical Annex.

only after time has passed that is it known whether the change is short term or longer term. Thus, irrevocable decisions on issues such as nuclear plant shutdowns could be made because of an expectation that the change is more permanent. Nevertheless, we believe the model provides a strong basis for a structure of regional prices.

We emphasize that in this study "electricity prices" are defined as what the generator is paid, not what the wholesale or retail customer pays. This is an important distinction because it recognizes that the middlemen who buy energy, bundle it, sell it, transmit it, distribute it, and do the administrative work to manage the system will also be paid. They, not only the generator, may be squeezed by competition. For perspective, in 1994, end-use prices ranged regionally from 6 to 12 cents per kWh. As will be presented in a following section, bulk power prices—prices a generator may expect—range regionally from about 1.5 to 2.2 cents per kWh. The difference is what the middlemen get.

Analysis and Calculations

We compare O&M costs with market price for each of the 71 sites to determine how each may fare in the competitive era. Sites in the three categories of cost and performance (Chapter I) are first reviewed according to their competitiveness. From this we developed a new categorization based on sites that are competitive in the market.

The prices are derived from the model that places power plants in the United States and Canada in one of three interconnected systems:

- Eastern Interconnection System,
- Western Interconnection System, or
- Electric Reliability Council of Texas (ERCOT)

Price projections are obtained for each of the 71 sites by dividing the United States and Canada into market areas, each of which is a North American Reliability Council (NERC) region or smaller. Appendix Table 2 at the end of the report shows, among other information, the market area in which each nuclear company is located. These market area price projections are compared with O&M costs of each site.

O&M costs in ($/MWh) are taken from the UDI data source for each site referenced in Chapter I. For this purpose, we used all O&M costs (fuel and non-fuel). We averaged cost over the time period 1993 to 1995 and held them constant through 2005. Whether O&M costs will be further reduced for the good performers or will increase for the poor performers is very difficult to assess. There is certainly a potential for cutting costs significantly at many sites. Whether this is done, as we have stated before, rests with owners and managers. Some good performers can cut costs further. On the other hand, some sites in the top performers category have little room for improvement. We decided to assume the O&M costs for each site will remain at the average of those from 1993 to 1995. Obviously, if owners further cut costs, more sites can remain in operation.

Next, a comparison is made between market clearing prices and O&M costs—the critical values for deciding whether to maintain the site in production.

Market Price Effects on the Future of Nuclear Sites

This section shows the viability of each of the 71 nuclear sites given the costs as reviewed in Chapter I, as well as the projected market prices. The focus is on vulnerability to permanent shutdown by 2005 because if the site is operating now, it probably will continue for another few years. Decisions on keeping a site in operation are more likely to be based on expectations for the longer term. Figure III-1 at the end of this chapter shows that 34 sites, representing 56,750 MWE are likely to be competitive, and 37 sites representing 40,103 MWE may not be competitive. There are 71 sites and 96,853 MWE in total.

Competitive Position of Top Performers

Although there is much similarity between the sites that are low cost and those that are viable considering market price, there are notable exceptions. **These exceptions are the most important findings of this chapter and perhaps in the study. Some of the top performing or low cost sites are vulnerable because they are located in regions of projected low market price, and some low performing or high cost**

sites seem to be viable because of regionally high market prices for electricity in the region in which they will compete.

This situation is shown in Figure III-1 and Table A-III-1 at the end of the chapter. Any site in regions with projected prices higher than O&M costs is considered competitive. Because of the uncertainties involved with this analysis, we also treated any site with less than $1 per MWh difference between market price and O&M cost as competitive. Many would expect that low operating cost sites are the ones that are likely to be valuable assets in producing revenue above fixed cost. However, of these 32 sites that are **top performers** (see Chapter I) 8 are considered to be not competitive in 2005. These are as follows:

- Davis Besse, owned by Toledo Edison
- Hatch, owned by The Southern Company
- Kewaunee, owned by Wisconsin Public Service
- Monticello, owned by Northern States Power
- Nine Mile Point 1, owned by Niagara Mohawk
- Peach Bottom, owned by PECO Energy
- Robinson 2, owned by Carolina Power and Light, and
- San Onofre, owned by Southern California Edison

If these 8 sites are shut down, there will be a decrease of 8,947 MWE, or 18 percent of the 50,689 MWE represented by this group.

Competitive Position of Good Performers

Figure III-2 and Table A-III-2 at the end of this chapter show that **in many cases** for the 22 sites that are in the group of **good performers** over the period from 1990 to 1995, **this level of performance is not sufficient to ensure viability in the market**. Our analysis shows that for 12 sites, O&M costs will be higher than market price. If these 12 sites shut down, there will be a decrease of 12,101 MWE or 45 percent of the 27,109 MWE represented by this group. These are as follows:

- Beaver Valley whose majority owner is Duquesne for Unit 1 and Ohio Edison for Unit 2

- DC Cook, owned by Indiana Michigan Power, a subsidiary of American Electric Power
- Clinton, owned by Illinois Power
- Fitzpatrick, owned by New York Power Authority
- Fort Calhoun, owned by Omaha Public Power District
- Ginna, owned by Rochester Gas and Electric
- Nine Mile Point 2, owned by Niagara Mohawk
- Palisades, owned by Consumers Power
- Vermont Yankee, owned by Vermont Yankee Nuclear Company
- Zion, owned by Commonwealth Edison
- Duane Arnold, whose majority owner is IES Industries, and
- River Bend, owned by Entergy Gulf States, a subsidiary of Entergy, Inc.

Competitive Position of Poor Performers

All of the 17 sites consisting of 19,055 MWE are found not to be cost competitive. These are as follows:

- Browns Ferry and Sequoyah, both owned by TVA
- Big Rock Point, owned by Consumers Power
- Connecticut Yankee and Millstone 1&2, owned or operated by Northeast Utilities
- Cooper, owned by Nebraska Public Power Authority

- Dresden and Quad Cities, both owned by Commonwealth Edison
- Fermi, owned by Detroit Edison
- Hope Creek and Salem, both operated by Public Service Electric and Gas—PSE&G along with PECO Energy are majority owners
- Indian Point 3, owned by New York Power Authority
- Indian Point 2, owned by Consolidated Edison
- Oyster Creek, owned by GPU
- Perry, owned by Cleveland Electric
- Pilgrim, owned by Boston Edison, and
- WNP 2, owned by Washington Public Power Supply System

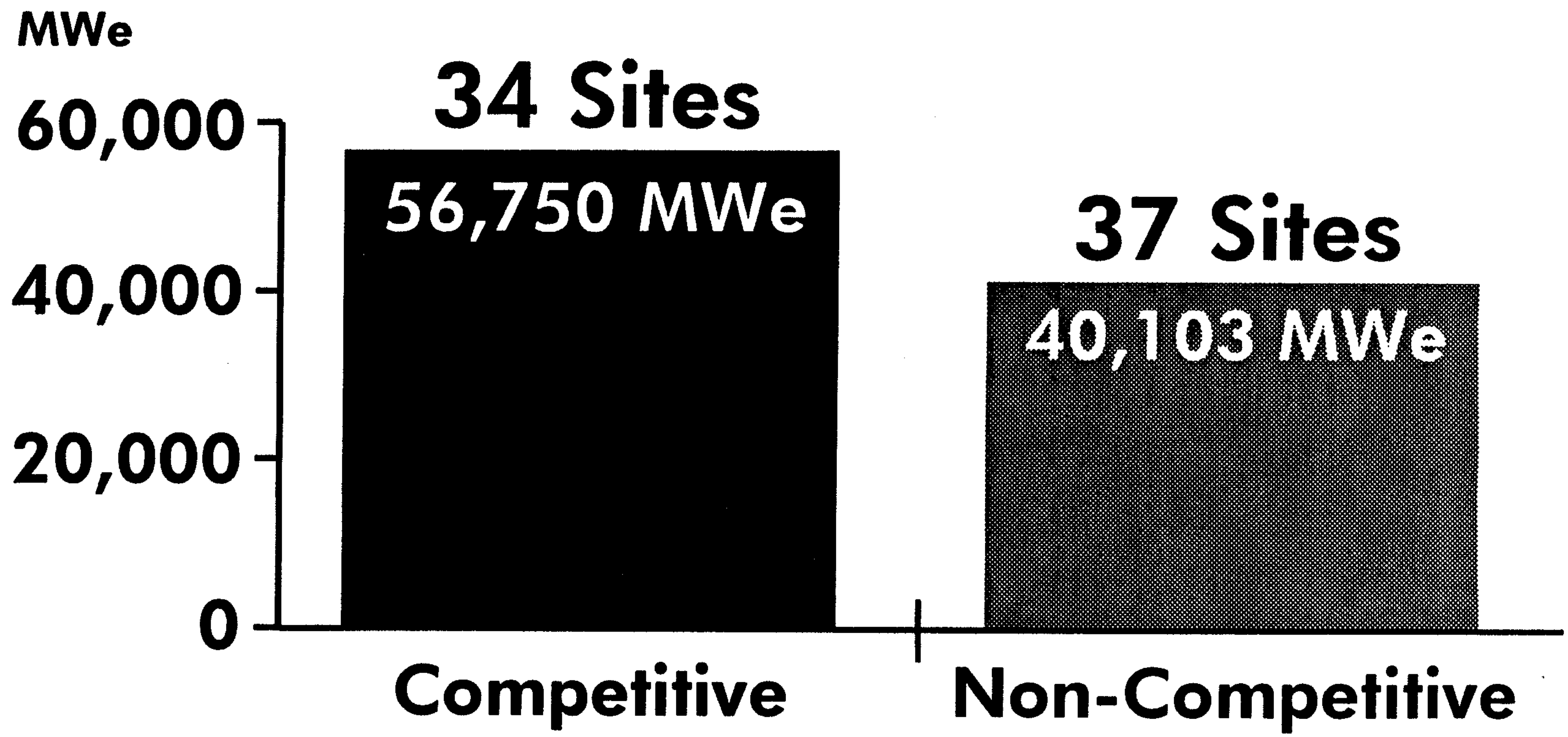
Figure III-2 and Table A-I-3 at the end of the chapter show these data.

Summary of the Effects of Competitive Prices on Nuclear Sites

The second element of the analysis—the comparison of expected market prices with expected costs of production—reveals that a significant number of additional sites are vulnerable to shut down compared with only looking at costs and performance. In a highly competitive market, only those facilities will survive that can produce at or less than market price in regions where they will compete. Although high-cost facilities are particularly vulnerable to market price, even some lower cost facilities are vulnerable to shutdown if prices in a particular region are low. Again, this analysis is based on a conservative assumption that electricity prices remain flat. There is a widespread opinion, however, that overall electricity prices will decline as a result of competition. It is also based on the assumption that site O&M costs will remain at the 1993 to 1995 level until 2005. Cumulatively, 40,103 MWE out of 96,853 MWE may not be competitive. This represents 40 percent of the total U.S. nuclear generating capacity.

Figure III-1

Future Competitiveness in 2005 Based Upon Price Forecasts



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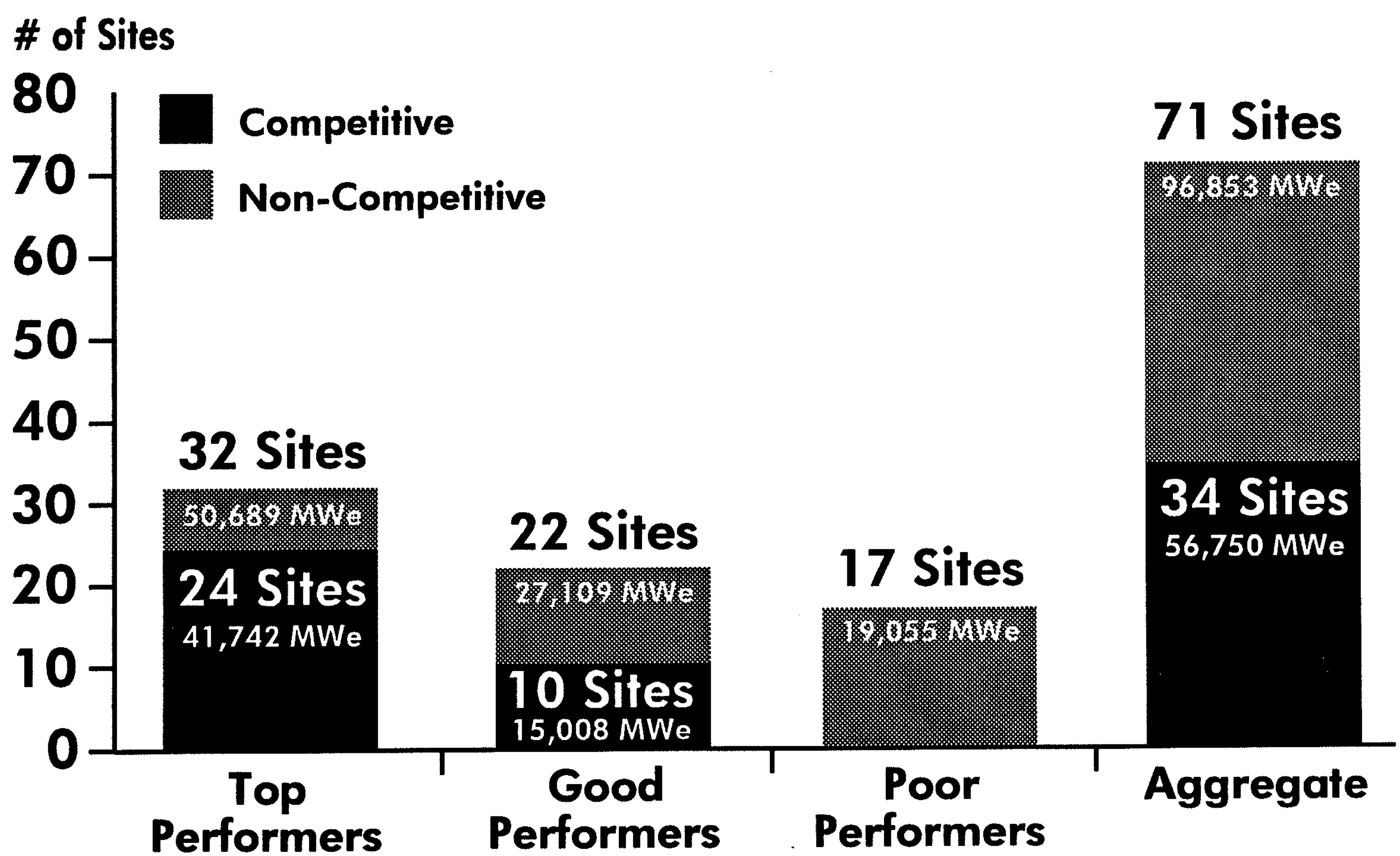
Cost Based On Data From UDI Nuclear Plant O&M Cost Data, 1961 - 1995
Competitiveness Based On Data From IREMM, Inc., North American Bulk Electricity Market Forecasts, 1997 -2010, October 1996

Figure III-2

Competitiveness Of Sites By Performance Category



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Note: Assumes prices performance stay constant until 2005

Cost Based On Data From UDI Nuclear Plant O&M Cost Data, 1961 - 1995
Price Based On Data From IREMM, Inc., North American Bulk Electricity Market Forecasts, 1997 -2010, October 1996

Table A-III-1. Competitive Position of Top Performers in O&M and Output Performance				
Site	Market Area	O&M Cost $/mWh*	Market Price $/mWh*	Market Price Minus O&M Cost
ARKANSAS ONE	SPPS	16.07	18.33	2.26
BRAIDWOOD	CECO	14.14	16.73	2.59
BRUNSWICK	VACR	19.64	19.10	-0.54
BYRON	CECO	13.85	16.73	2.88
CALVERT CLIFFS	MAAC	18.57	19.69	1.12
CATAWBA	VACR	16.15	19.10	2.95
COMANCHE PEAK	TUEC	17.22	19.17	1.95
CRYSTAL RIVER	FLA	20.03	22.02	1.99
DAVIS BESSE	**CAPC**	**21.13**	**17.17**	**-3.96**
HATCH	**SOUT**	**20.63**	**18.29**	**-2.34**
KEWAUNEE	**WUMS**	**17.70**	**16.56**	**-1.14**
LIMERICK	MAAC	15.34	19.69	4.35
MAINE YANKEE	NEPL	14.29	22.25	7.96
MCGUIRE	VACR	16.71	19.10	2.39
MONTICELLO	**MAPP**	**17.71**	**14.93**	**-2.78**
NINE MILE POINT 1	**UPNY**	**23.86**	**20.46**	**-3.40**
NORTH ANNA	VACR	11.97	19.10	7.13
OCONEE	VACR	14.74	19.10	4.36
PALO VERDE	APS	18.41	19.10	0.69
PEACH BOTTOM	**MAAC**	**20.98**	**19.69**	**-1.29**
POINT BEACH	WUMS	14.34	16.56	2.22
PRAIRIE ISLAND	MAPP	13.22	14.93	1.71
ROBINSON TWO	**VACR**	**21.26**	**19.10**	**-2.16**
SAN ONOFRE	**SCE**	**19.94**	**18.08**	**-1.86**
SEABROOK	NEPL	18.79	22.25	3.46
SOUTH TEXAS	HL&P	18.45	18.54	0.09
SUMMER	VACR	19.11	19.10	-0.01
SURRY	VACR	15.43	19.10	3.67
THREE MILE ISLAND	MAAC	20.24	19.69	-0.55
TURKEY POINT 3&4	FLA	20.63	22.02	1.39
VOGTLE	SOUT	12.52	18.29	5.77
WOLF CREEK	SPPN	14.55	17.19	2.64
Number of Sites		32		
Number of Sites not Competitve		8		
Highlighted sites are those not projected to be competitive in 2005				
*1993 -1995 O&M costs are held constant through 2005, and 1997 market prices are held constant through 2005.				

Fuel and non-fuel O&M costs are for each site taken from the UDI database described in Chapter I.

Table A-III-2. Competitive Position of Good Performers in O&M Cost and Output Performance				
Site	Market Area	O&M Cost $/mWh*	Market Price $/mWh*	Market Price Minus O&M Cost
BEAVER VALLEY	**CAPC**	**24.61**	**17.17**	**-7.44**
CALLAWAY	EMO	15.52	17.77	2.25
CLINTON	**SCIL**	**24.44**	**14.69**	**-9.75**
DC COOK	**AEP**	**19.77**	**15.54**	**-4.23**
DIABLO CANYON	PG&E	18.96	19.34	0.38
DUANE ARNOLD	**MAPP**	**24.35**	**14.93**	**-9.42**
FARLEY	SOUT	16.8	18.29	1.49
FITZPATRICK	**UPNY**	**26.06**	**20.46**	**-5.60**
FORT CALHOUN	**MAPP**	**30.06**	**14.93**	**-15.13**
GINNA	**UPNY**	**22.33**	**20.46**	**-1.87**
GRAND GULF	SPPS	18.53	18.33	-0.20
HARRIS	VACR	17.23	19.1	1.87
LASALLE	CECO	15.94	16.73	0.79
MILLSTONE 3	NEPL	19.59	22.25	2.66
NINE MILE POINT 2	**UPNY**	**22.31**	**20.46**	**-1.85**
PALISADES	**CP**	**24.55**	**17.73**	**-6.82**
RIVER BEND	**SPPS**	**31.55**	**18.33**	**-13.22**
ST LUCIE	FLA	20.8	22.02	1.22
SUSQUEHANNA	MAAC	18.95	19.69	0.74
VERMONT YANKEE	**NEPL**	**23.29**	**22.25**	**-1.04**
WATERFORD 3	SPPS	17.15	18.33	1.18
ZION	**CECO**	**19.07**	**16.73**	**-2.34**
Number of Sites		22		
Number of Sites not Competitive		12		
Highlighted sites are those not projected to be competitive in 2005				
*1993 - 1995 O&M costs are held constant through 2005, and 1997 market prices are held constant through 2005.				

Table A-III-3. Competitive Position of Poor Performers in O&M Cost and Output Performance*

Site	Market Area	O&M Cost $/mWh*	Market Price $/mWh*	Market Price Minus O&M Cost
BROWNS FERRY	**TVA**	**23.85**	**16.73**	**-7.12**
BIG ROCK POINT	**CP**	**59.38**	**17.73**	**-41.65**
CONN YANKEE	**NEPL**	**28.96**	**22.25**	**-6.71**
COOPER	**MAPP**	**31.93**	**14.93**	**-17.00**
DRESDEN	**CECO**	**36.66**	**16.73**	**-19.93**
FERMI	**DECO**	**30.33**	**17.88**	**-12.45**
HOPE CREEK	**MAAC**	**21.29**	**19.69**	**-1.60**
INDIAN POINT THREE	**UPNY**	**90.27**	**20.46**	**-69.81**
INDIAN POINT TWO	**SENY**	**25.32**	**20.52**	**-4.80**
MILLSTONE 1&2	**NEPL**	**33.06**	**22.25**	**-10.81**
OYSTER CREEK	**MAAC**	**32.37**	**19.69**	**-12.68**
PERRY	**CAPC**	**26.69**	**17.17**	**-9.52**
PILGRIM	**NEPL**	**30.81**	**22.25**	**-8.56**
QUAD CITIES	**CECO**	**31.67**	**16.73**	**-14.94**
SALEM	**MAAC**	**27.84**	**19.69**	**-8.15**
SEQUOYAH	**TVA**	**24.73**	**16.73**	**-8.00**
WNP 2	**BPA**	**21.38**	**19.23**	**-2.15**
Number of Sites	17			

*All sites are non-competitive in 2005

*1993 - 1995 O&M costs are held constant through 2005, and 1997 market prices are held constant through 2005.

Chapter IV—Vulnerable Sites and Regional Natural Gas Potential

The focus of the analysis up to this point has been on sites as categorized according to cost and performance developed in Chapter I. We now move on to the next critical step, to group all sites according to whether each is projected to be competitive in the market. Sites are also evaluated for vulnerability to shutdown for reasons other than or in addition to their competitive status.

Result from the Quantitative Analysis

Of the 71 sites included in this report, 34 are projected to be competitive according to the criteria that the market price is at least as high as the O&M costs. The remaining 37 sites are not projected to be competitive in 2005. These sites have a total capacity of 40,103 MWE and represent 40 percent of the total of 96,853 of the MWE included in this study. Vulnerable sites tend to be those with lower capacity. The 34 sites that are competitive average 1669 MWE of capacity per site. The 37 that are not competitive have an average of 1083 MWE per site. Twenty-one sites that are not competitive have site capacity below 1000 MWE, as compared to six of the competitive sites that are below 1000 MWE. There may appear to be a correlation between capacity and competitiveness. However, a more efficient way of finding vulnerable sites is to make direct comparisons between O&M costs and market price. Tables A-IV-1 and A-IV-2 at the end of this chapter show these results.

Of course, we need to restate that our analysis is not meant to be all encompassing, but looks at how individual sites fare if prices and O&M costs remain the same as they were in 1993 to 1995 through 2005.

Modifications to the Quantitative Analysis

We believe that an owner's anticipation of a site's inability to compete in the market will be the primary reason for shutdown. Other factors, such as license expiration, regulatory difficulties and lack of on-site waste storage, can lead to shutdown also.

As reviewed in Chapter I, a major uncertainty regarding the future of nuclear facilities is license renewal. Even if a licensee decides to apply for renewal, the application must not only be approved by NRC, but is subject to a public hearing. Public interest groups that take special interest in nuclear matters can pose considerable opposition to license renewal. Licensees will no doubt take this factor into account in deciding whether to continue facility operation. Thus, we believe that sites where licenses expire by 2007 to 2010 are vulnerable to shutdown even if not for economic reasons. These sites are Dresden, Big Rock Point, and Palisades. Connecticut Yankee's license also expires in 2007, but, of course, it has already been decided to close the facility.

Regulatory difficulties continue to create uncertainties regarding the continued operation of some facilities. Millstone 3, a prime example, presents a dilemma in projecting whether it is vulnerable to permanent shutdown. In keeping with our approach, we assume that management, either its current owner or a potential new one, will eventually bring the facility into regulatory compliance and again make it an economic asset to its owner.

The following information is provided to show why the future of Millstone 3, as well as the other facilities owned by Northeast Utilities (NU), is uncertain. NU is under severe NRC regulatory pressure due to safety concerns at most of its nuclear facilities. An auditor's report to the Connecticut Department of Public Utility Control severely criticized NU for being led by a board of directors with little knowledge of the nuclear industry.[44] Managers were preoccupied with saving money. The auditors found that NU may no longer be possible to operate safe and efficient nuclear units. NU does not agree with the report and responded that some of the problems had been identified by its own studies. In 1996, all units

[44] "Utility Mismanaged Nuclear Plants for a Decade, State Agency Says," *Associated Press*, December 31, 1996.

operated by the company except for Seabrook were shut down due to regulatory difficulties. The joint owners have now decided to permanently shut down Connecticut Yankee.[45] The company has announced that only one of the three Millstone units will return to service in 1997, the others are planned for 1998. Purchased power is costing $30 million per month. Its financial ratings are expected to be downgraded.[46]

There will be many dynamics that cannot now be accounted for in electricity markets as they move to competition. These dynamics, of course, have major influences on whether nuclear sites will shut down.

Regional Potential for Natural Gas Markets

Now that the 37 sites—consisting of 40,103 MWE, or 41 percent of the total of 96,853 MWE that are vulnerable to shutdown—have been identified, the remainder of the report addresses the regional implications for the use of natural gas as a replacement generating source for these sites. Following is a preliminary review of the potential for sales of natural gas.

First we estimate the electrical production per year that would need to be supplied from another source if these sites are shut down. Estimation is done using the 1993 to 1995 average net generation—production after deducting in-plant electricity use—for each vulnerable site from the UDI database (see Chapter I).

Many analysts expect that reserve margins will go down over the next few years as unused generating capacity is needed. We expect that the reserve margin will go below the NERC standard of about 18 percent. As electricity sales and purchases are increasingly freed from utility and state boundaries, reserve margin needs will be reduced for each individual company. Falling reserve margins will dampen the need for capacity, so

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[45] "Connecticut Yankee will Close Permanently; Decommissioning Costs to Total $425 Million," *Electric Power Daily*, The McGraw-Hill Companies, Dec. 5, 1996, p. 1.

[46] "Moody's Puts NU Subsidiaries Under Review for Downgrade." *The Energy Daily*, King Publishing Group, September 9, 1996, p. 3.

that even if nuclear plants are closed, new capacity may not be needed immediately.

Next we estimate how much gas would be needed if **all** the electrical output from the vulnerable nuclear sites were to be supplied by natural gas-fired generation. Of course, we do not believe that will occur. This assumption merely establishes the upper boundary. It is assumed that all the replacement natural gas units will be advanced combined cycle having an average heat rate of 6500 *btus* per kWh.[47] Quite obviously, only a portion of the shutdown nuclear capacity will be provided by natural gas. Even a significant share of this total would be a large market for gas. Tables A-IV-3 and A-IV-4 and Figures IV-1, IV-2, and IV-3 at the end of this chapter show the regional MWE that are vulnerable to shutdown, the kWh that must be replaced if all these sites shut down, and the cubic feet of natural gas that would be utilized if all the output were to be replaced by advanced combined cycle gas facilities.

Some regions will be quite heavily impacted by these shutdowns.

- All 6 operating nuclear sites in New York, representing over 4,700 MWE, may be shutdown;

- All 7 sites, representing over 7,600 MWE, are vulnerable to shut down in the ECAR region, which consists of Kentucky, Michigan, Ohio, western Pennsylvania, and West Virginia;

- In the MAPP region, consisting primarily of Iowa, Minnesota, Nebraska, and the Dakotas there are 4 sites representing about 2,300 MWE, or about 60 percent of total nuclear generation in the region vulnerable to shut down;

- In the MAAC region, Delaware, Maryland, New Jersey, and nearly all of Pennsylvania, 4 sites, or about 47 percent of the nuclear capacity representing about 6,000 MWE in the region are vulnerable to shut down;

[47] *Annual Energy Outlook 1996*, DOE/EIA-0383(96), *op. cit.*, p. 32.

- In the NEPOOL region (New England), 4 sites representing about 51 percent of the nuclear capacity representing about 3,250 MWE in the region are vulnerable to down; and

- In the MAIN region, which consists of Illinois, northern and eastern Wisconsin, and eastern Missouri, 5 sites representing 45 percent of 6,600 MWE of capacity in the region are vulnerable to shut down.

Total gas use for electricity generation in 1995 was 3,460 bcf (reported as 3.46 trillion cubic feet).[48] Replacing the output from the vulnerable nuclear facilities represents 1,550 bcf of natural gas. This is about 45 percent of the gas used for electricity generation in 1995. Following are the most notable findings.

- 315 bcf or about 20 percent of the total potential gas use is in the Northeast—New England, New York, NERC regions NEPOOL and NYPP;

- 230 bcf or 15 percent of the total potential gas use is in the mid-Atlantic—the MAAC region, thus a total of 545 bcf or 35 percent of the potential is in the Northeast;

- 300 bcf or 20 percent of the total potential gas use is in Michigan, Ohio, and western Pennsylvania—the ECAR region;

- 220 bcf or 15 percent of the total potential gas use is in Illinois, eastern Missouri, and eastern Wisconsin—the MAIN region, thus including the MAPP region, there is a total gas potential of about 615 bcf in the Midwest.

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[48] *Annual Energy Outlook 1997*, Energy Information Administration, December 1996, p. 114.

Commentary on How These Results May Be Viewed by Facility Owners

Neither the simulated prices nor the estimates of future O&M costs can be considered forecasts subject to formal tests of their validity. Nor should conclusions be made on an exact comparison of costs with prices. But the results are a powerful display of the vulnerability of any one site.

Although we have written the chapter in terms of projections, both for the economic variables and regulatory and political factors, it should be kept in mind that what will most influence site shutdown or continued operation is not projections or forecasts, but owners' **expectations of the future**. Our analysis is but one view of the future and is based on conservative assumptions. If owners believe other scenarios better represent the future, they will act on those and not the ones provided here.

Figure IV-1

MWe Of Nuclear Capacity Vulnerable To Shutdown By NERC Region

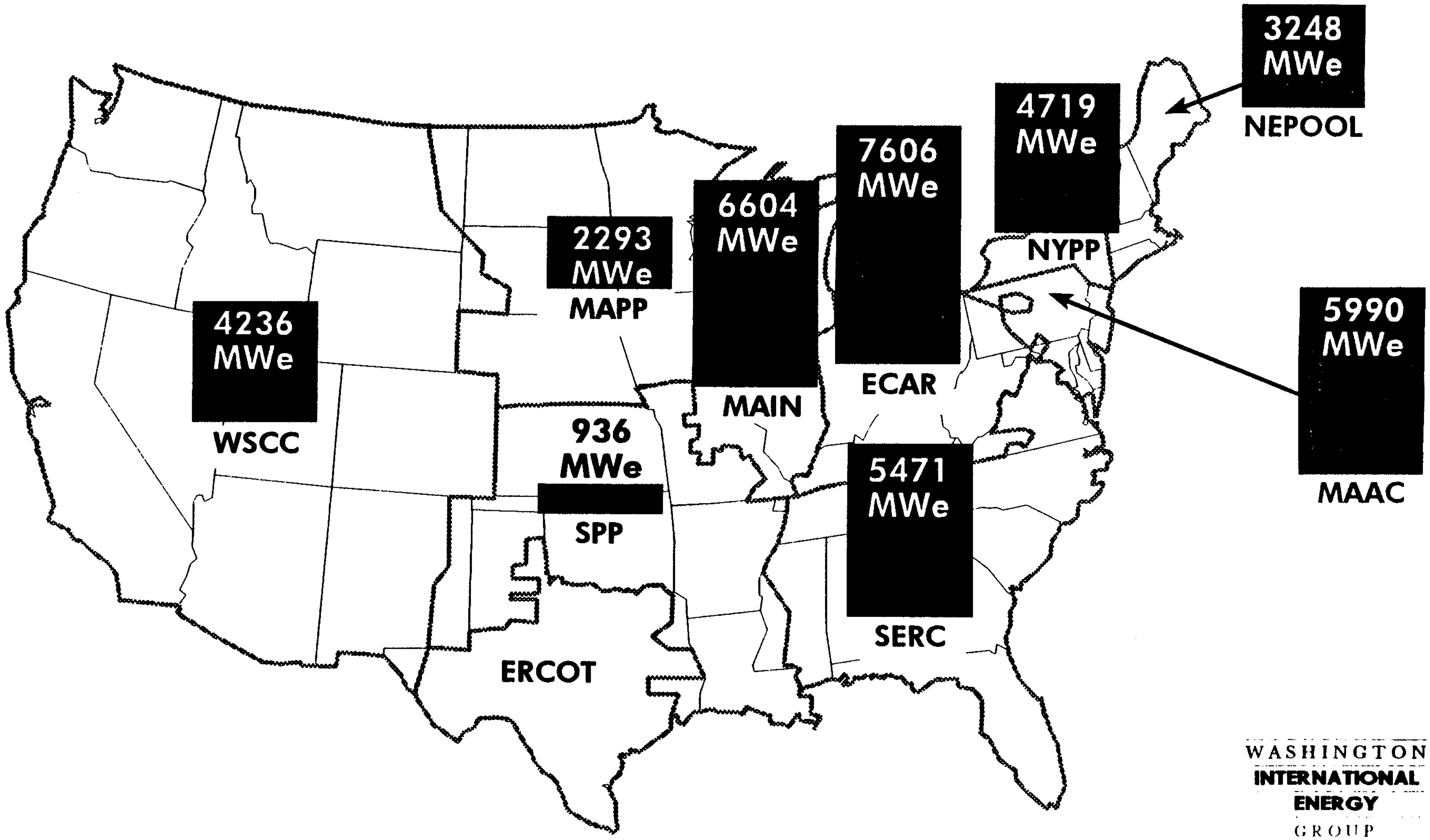

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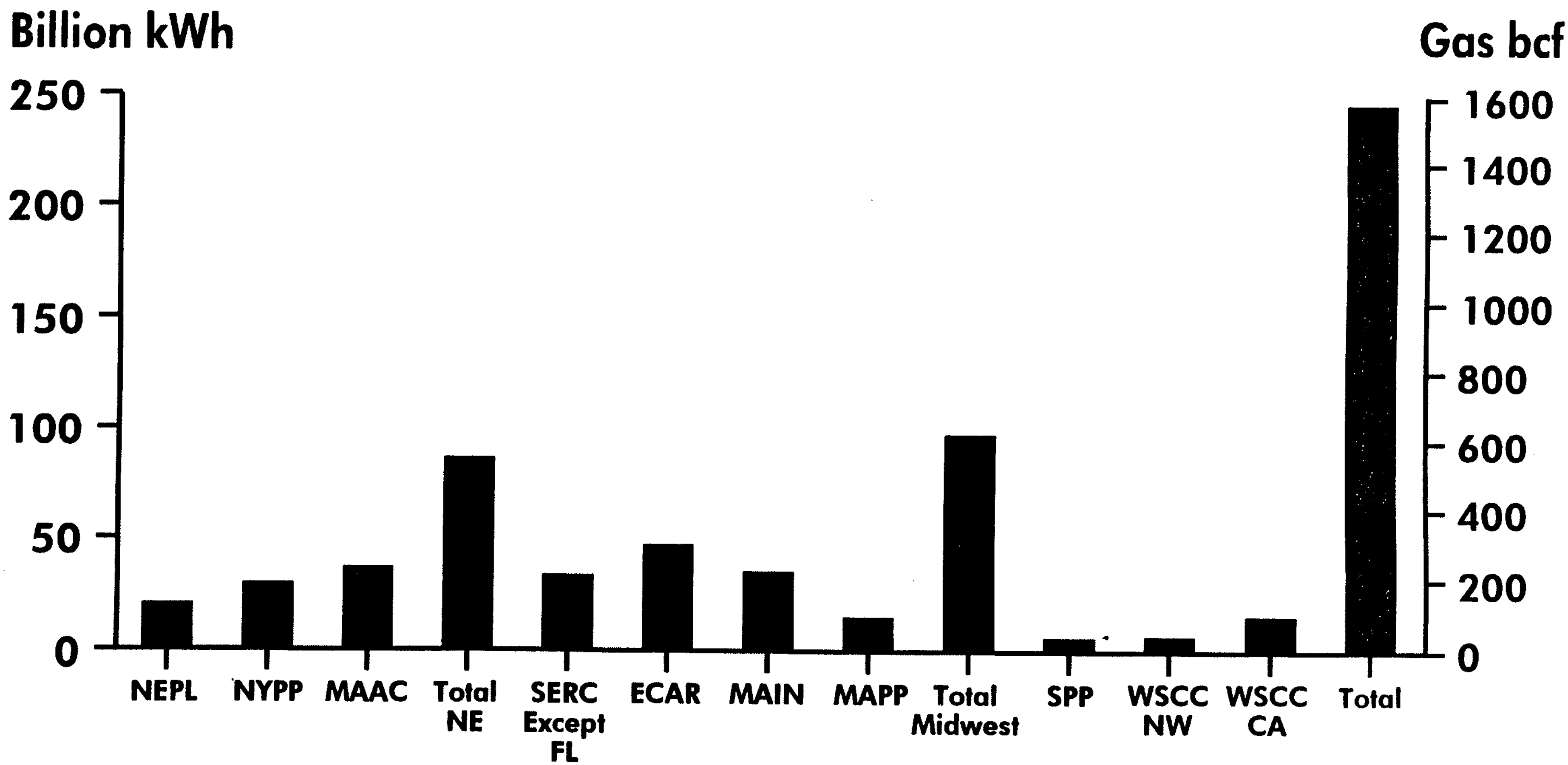
Figure IV-2

BCF Of Gas If Used To Replace KWH Of Electricity



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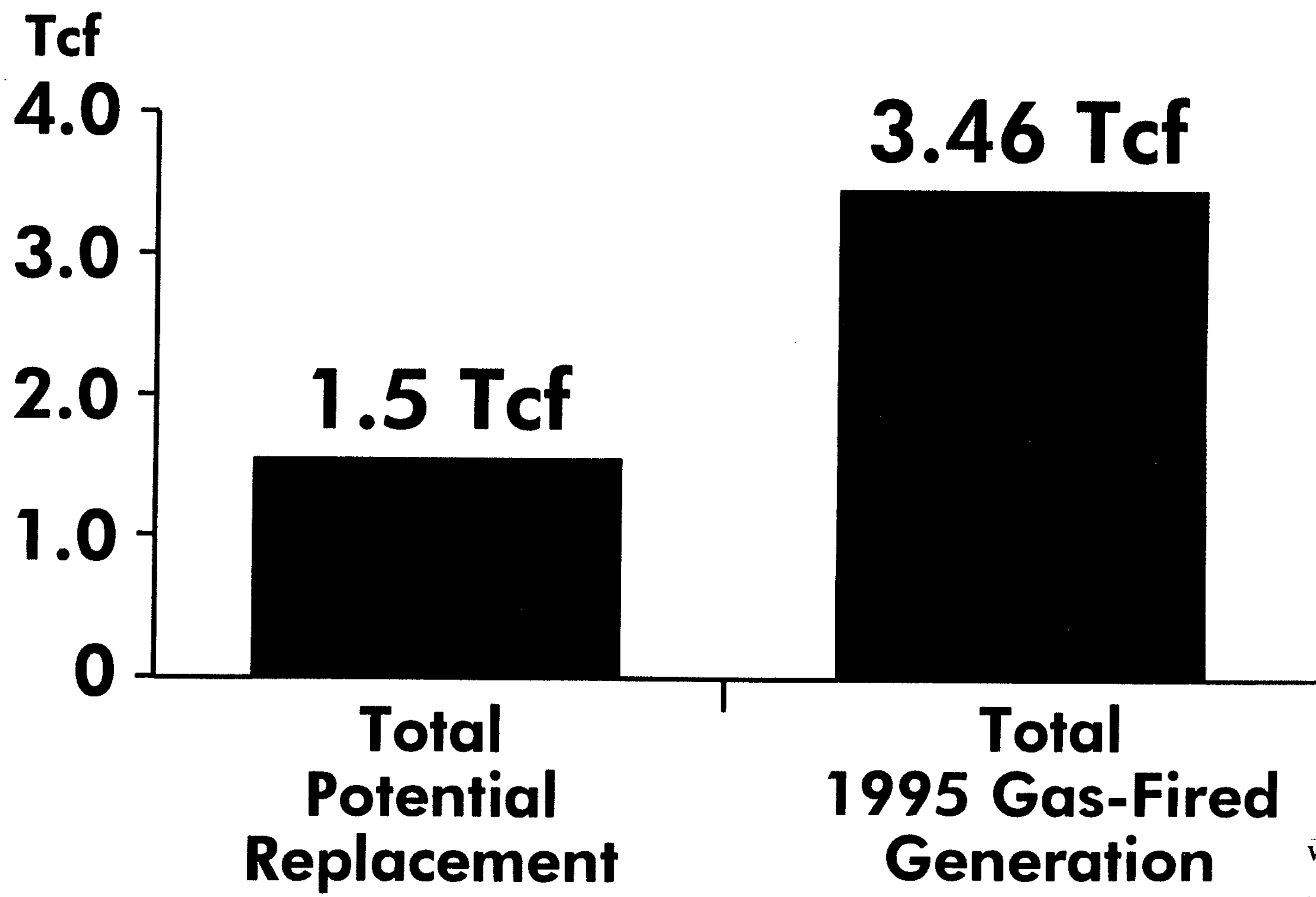
Source For Estimating Gas Use, cf/kwh: Annual Energy Outlook 1996, DOE/EIA-0383(96), January 1996

Figure IV-3

Gas Replacement Compared To 1995 Gas-Fired Generation



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Source For 1995 Gas Use: Annual Energy Outlook 1997, DOE/EIA-0383(97), December 1996

Table A-IV-1. Nuclear Sites That are Cost Competitive with Regional Price					
Site	Site MWe Net MDC	Market Area	O&M Cost $/mWh*	Market Price $/mWh*	Market Price Minus O&M Cost
ARKANSAS ONE	1694	SPPS	16.07	18.33	2.26
BRAIDWOOD	2240	CECO	14.14	16.73	2.59
BRUNSWICK	1521	VACR	19.64	19.10	-0.54
BYRON	2210	CECO	13.85	16.73	2.88
CALLAWAY	1115	EMO	15.52	17.77	2.25
CALVERT CLIFFS	1675	MAAC	18.57	19.69	1.12
CATAWBA	2258	VACR	16.15	19.10	2.95
COMANCHE PEAK	2300	TUEC	17.22	19.17	1.95
CRYSTAL RIVER	818	FLA	20.03	22.02	1.99
DIABLO CANYON	2160	PG&E	18.96	19.34	0.38
FARLEY	1634	SOUT	16.80	18.29	1.49
GRAND GULF	1143	SPPS	18.53	18.33	-0.20
HARRIS	860	VACR	17.23	19.10	1.87
LASALLE	2072	CECO	15.94	16.73	0.79
LIMERICK	2110	MAAC	15.34	19.69	4.35
MAINE YANKEE	860	NEPL	14.29	22.25	7.96
MCGUIRE	2258	VACR	16.71	19.10	2.39
MILLSTONE 3	1137	NEPL	19.59	22.25	2.66
NORTH ANNA	1787	VACR	11.97	19.10	7.13
OCONEE	2538	VACR	14.74	19.10	4.36
PALO VERDE	3663	APS	18.41	19.10	0.69
POINT BEACH	970	WUMS	14.34	16.56	2.22
PRAIRIE ISLAND	1125	MAPP	13.22	14.93	1.71
SEABROOK	1150	NEPL	18.79	22.25	3.46
SOUTH TEXAS	2502	HL&P	18.45	18.54	0.09
ST LUCIE	1678	FLA	20.80	22.02	1.22
SUMMER	885	VACR	19.11	19.10	-0.01
SURRY	1562	VACR	15.43	19.10	3.67
SUSQUEHANNA	2134	MAAC	18.95	19.69	0.74
THREE MILE ISLAND	786	MAAC	20.24	19.69	-0.55
TURKEY POINT 3&4	1332	FLA	20.63	22.02	1.39
VOGTLE	2338	SOUT	12.52	18.29	5.77
WATERFORD 3	1075	SPPS	17.15	18.33	1.18
WOLF CREEK	1160	SPPN	14.55	17.19	2.64
Total MWE	56750				
Number of Sites	34				
*1993 -1995 O&M costs are held constant through 2005, and 1997 market prices are held constant through 2005.					

Table A-IV-2 Nuclear Sites That are NOT Cost Competitive with Regional Price					
Site	Site MWe Net MDC	Market Area	O&M Cost $/mWh*	Market Price $/mWh*	Market Price Minus O&M Cost
BEAVER VALLEY	1630	CAPC	24.61	17.17	-7.44
BIG ROCK POINT	67	CP	59.38	17.73	-41.65
BROWNS FERRY	1065	TVA	23.85	16.73	-7.12
CLINTON	930	SCIL	24.44	14.69	-9.75
CONN YANKEE	560	NEPL	28.96	22.25	-6.71
COOPER	764	MAPP	31.93	14.93	-17.00
DC COOK	2060	AEP	19.77	15.54	-4.23
DAVIS BESSE	868	CAPC	21.13	17.17	-3.96
DRESDEN	1545	CECO	36.66	16.73	-19.93
DUANE ARNOLD	515	MAPP	24.35	14.93	-9.42
FERMI	1085	DECO	30.33	17.88	-12.45
FITZPATRICK	774	UPNY	26.06	20.46	-5.60
FORT CALHOUN	478	MAPP	30.06	14.93	-15.13
GINNA	470	UPNY	22.33	20.46	-1.87
HATCH	1506	SOUT	20.63	18.29	-2.34
HOPE CREEK	1031	MAAC	21.29	19.69	-1.60
INDIAN POINT TWO	951	SENY	25.32	20.52	-4.80
INDIAN POINT THREE	965	UPNY	90.27	20.46	-69.81
KEWAUNEE	511	WUMS	17.70	16.56	-1.14
MILLSTONE 1&2	1514	NEPL	33.06	22.25	-10.81
MONTICELLO	536	MAPP	17.71	14.93	-2.78
NINE MILE POINT 1	565	UPNY	23.86	20.46	-3.40
NINE MILE POINT 2	994	UPNY	22.31	20.46	-1.85
OYSTER CREEK	619	MAAC	32.37	19.69	-12.68
PALISADES	730	CP	24.55	17.73	-6.82
PEACH BOTTOM	2128	MAAC	20.98	19.69	-1.29
PERRY	1166	CAPC	26.69	17.17	-9.52
PILGRIM	670	NEPL	30.81	22.25	-8.56
QUAD CITIES	1538	CECO	31.67	16.73	-14.94
RIVER BEND	936	SPPS	31.55	18.33	-13.22
ROBINSON TWO	683	VACR	21.26	19.10	-2.16
SALEM	2212	MAAC	27.84	19.69	-8.15
SAN ONOFRE	2150	SCE	19.94	18.08	-1.86
SEQUOYAH	2217	TVA	24.73	16.73	-8.00
VERMONT YANKEE	504	NEPL	23.29	22.25	-1.04
WNP 2	1086	BPA	21.38	19.23	-2.15
ZION	2080	CECO	19.07	16.73	-2.34
Total MWE	40103				
Number of Sites	37				

*1993 - 1995 O&M costs are held constant through 2005, and 1997 market prices are held constant through 2005.

Table IV-3. Nuclear Sites That are Vulnerable to Shutdown

Site	Operator	NERC Region	Site MWe net MDC	Regional Nuclear Gen. Cap. MWe	Percent Sh'down of Region Nuclear	Total Gen Capacity MWe	Percent Sh'down of Region Total Gen.
VERMONT YANKEE	VT Yankee Nuc.	NEPOOL	504				
CONN YANKEE	NU	NEPOOL	560				
MILLSTONE 1&2	NU	NEPOOL	1514				
PILGRIM	Boston Ed.	NEPOOL	670				
NEPOOL, Total			3248	6380	51	25660	13
GINNA	Rochester G&E	NYPP	470				
FITZPATRICK	NYPA	NYPP	774				
INDIAN POINT THREE	NYPA	NYPP	965				
INDIAN POINT TWO	Con Ed.	NYPP	951				
NINE MILE POINT 1	Niagara Mohawk	NYPP	565				
NINE MILE POINT 2	Niagara Mohawk	NYPP	994				
NYPP, Total			4719	4870	100	32980	14
OYSTER CREEK	GPU Nuclear	MAAC	619				
SALEM	PSE&G	MAAC	2212				
HOPE CREEK	PSE&G	MAAC	1031				
PEACH BOTTOM	PECO Energy	MAAC	2128				
MAAC, Total			5990	12700	47	53990	11
HATCH	So. Nuc. Oper.	SERC	1506				
SEQUOYAH	TVA	SERC	2217				
BROWNS FERRY	TVA	SERC	1065				
ROBINSON TWO	CP&L	SERC	683				
SERC outside FL, Total			5471	25360	22	121480	5
DC COOK	Ind/Mich Pwr.	ECAR	2060				
BEAVER VALLEY	Duquesne	ECAR	1630				
PERRY	Clev. Electric	ECAR	1166				
DAVIS BESSE	Toledo Edison	ECAR	868				
FERMI	Det. Ed.	ECAR	1085				
BIG ROCK POINT	Consumers Pwr	ECAR	67				
PALISADES	Consumers Pwr.	ECAR	730				
ECAR, Total			7606	7630	100	108000	7
KEWAUNEE	Wisc. Pub. Ser.	MAIN	511				
ZION	Com Ed.	MAIN	2080				
DRESDEN	Com Ed.	MAIN	1545				
QUAD CITIES	Com Ed.	MAIN	1538				
CLINTON	Illinois Power	MAIN	930				
MAIN, total			6604	14840	45	51390	13
COOPER	NPPD	MAPP	764				
DUANE ARNOLD	IES Utilities	MAPP	515				
FORT CALHOUN	OPPD	MAPP	478				
MONTICELLO	Northern States	MAPP	536				
MAPP, Total			2293	3720	62	34040	7
RIVER BEND	Entergy Oper.	SPP	936				
SPP, Total			936	5890	16	73070	1
WNP 2	WPPSS	WSCC	1086				
WSSC, Northwest, Total			1086	1090	100	50990	2
SAN ONOFRE	So. Calif. Edison	WSCC	2150				
WSSC, CA & NV, Total			2150	5130	42	56010	4
	Number of Sites		37				
	Total MWe		40103				

Table IV-4. Total Regional Gas Potential if all Vulnerable Nuclear Sites Shut Down

Region	NREC Region	MWe Net MDC	Annual Product. billion kWhr*	Annual Gas potenti Billion cf**	Regional Nuclear Billion kWhr 1995	Percent Nuclear Sh'downs of Total*** kWhr 1995
New England	NEPL	3248	20.4	128.4	41.5	49.1
New York	NYPP	4719	29.5	185.9	31.3	94.3
Mid Atlantic	MAAC	5990	36.8	231.9	85.1	43.2
Total Northeast		13957	86.6	546.2	157.8	54.9
Southeast except Florida	SERC	5471	33.4	210.5	167.8	19.9
West. PA, OH, MI, KN, WV	ECAR	7606	47.4	298.6	49.1	96.5
Illinois, East. & North. WI, East. MO	MAIN	6604	35.3	222.4	95.4	37.0
West. WI, MN, ND, SD, NE	MAPP	2293	14.8	93.1	25.5	58.0
Total Midwest		16503	97.4	614.1	337.7	28.8
West. MO, KS,OK, AR, LA,	SPP	936	6.0	38.0	42.3	14.2
Northwest	WSSC	1086	6.8	42.8	6.3	108.1
California	WSSC	2150	15.7	99.2	37.3	42.3
Total****		40103	246.0	1550.8	609.8	40.3
Percent Potential is of 1995 Electricity Generation with Gas				44.8		

*Average 1993 to 1995

**Assumes advanced combined cycle units with heat rate of 6500 btu/kwh, based on Annual Energy Outlook 1996, DOE/EIA-0383(96), January 1996, p. 32.

***Percents only approximate because our calculations are 1993-95, EIA is 1995 only

****Does not include regions where there are no nuclear site shutdowns projected.

Chapter V—Other Important Issues

Stranded Costs—Defining the Issue

Recovery of stranded costs will be determined by the political process. A few states and FERC have already enacted regulations which probably encompass the actions being considered by many other states. Stranded costs will not directly impact the viability of nuclear facilities; viability is determined by operating and maintenance costs compared with expected market prices. But success in stranded cost recovery will indirectly affect viability if owners do not have the resources to maintain and improve the facilities. The stranded cost recovery process is at an early stage and it is too early to identify how individual sites may be affected.

Stranded costs resulting from the electric industry's move to competitive markets is a top concern for utilities, FERC, and state PUCs and consumers. At issue is what costs should be recoverable, and why, how, and when to recover them. There are widely different estimates as to the magnitude of stranded costs, primarily because there is no commonly accepted definition. Without new protection, utilities may no longer be able to recover this capital. The prospect that such investments might not be recovered in a market environment, leaves these costs "stranded."

Utilities with large, more recent nuclear investments tend to have the largest exposure to stranded costs. However, any utility with large unrecovered investments is affected. Failure to recover these costs may lead to serious consequences, including bankruptcy, for the company.

Calculating the actual dollar amount of these costs is difficult and depends on unique financial arrangements. Many external variables will influence the potential recovery of these costs. Among them are the pace of change, demand growth and the political process.

Under rate regulation, a plant is in the rate base and can recover capital costs as long as it is "used and useful." With a regulated industry, if a plant were to be shut down before it is completely depreciated, the utility could negotiate with the PUC or other rate making authority to recover the remaining investment costs. Provisions to recover at least some of the remaining investment were made for most, if not all, of the commercial U.S. nuclear facilities that have been shut down prematurely.

In a competitive market without an arrangement through the state or FERC, invested costs lose their association with a particular facility and are the same as any other sunk costs to the corporation. Thus, in the competitive world, the source of indebtedness is not important—only that it exists for the company. Whether the revenue for paying the indebtedness comes from the facility for which the investment was made, or from some other enterprise, makes no difference in repaying the debt.

There are two ways for a company to deal with stranded costs.

- try to recover costs through governmental mechanisms as have been initiated in a few states;

- make the company as profitable as possible so that stranded costs can be recovered in the competitive market.

Of course, companies are expected to pursue both options simultaneously. But those that concentrate most of their efforts on the political process for cost recovery may find their competitors have already cut costs, built markets, and attracted all the best customers.

The Washington International Energy Group believes that most states will provide for stranded cost recovery, even if not 100 percent of all such costs. Thus, we believe that stranded costs will not be a direct determinant in shutting down a nuclear plant.

Nevertheless, shutting the plant down will do nothing to recover stranded costs. A nuclear plant that has high operating cost or other defects may be shut down to improve company profitability. But a facility with low operating costs could be the best choice for enhancing company profitability—even if it has large stranded costs.

Stranded cost recovery could have an important indirect impact on continuing a plant's operation. If, for an investor-owned utility, these costs are mostly debt, the company may not be able to make needed capital expenditures, including improvements to enhance the economic performance of its nuclear facilities. This situation could eventually force a decision to shut down a low-performing nuclear plant.

Pace and Direction of State and Regional Moves to Competition

Despite opposition by "stranded cost-free" companies, a consensus is emerging in the United States that it is equitable to recover stranded costs from those that benefit from competition and those that have traditionally been the beneficiaries of the monopoly's "obligation to serve." Many also believe that stranded cost recovery is essential to building support for competition. If companies do not receive some form of stranded cost recovery, they will probably fight the move to competition. There is a widespread—although far from universal—opinion that prudently incurred costs should be recovered over a relatively short period of time. Many U.S. utilities, including some with smaller, fully depreciated nuclear facilities, do not have such a problem. This creates an inter-utility, and inter-regional, equity problem that has not yet been addressed by regulators and legislators.

There are now four examples in the United States in which a formal stranded cost recovery program is a component of a comprehensive competition package:

- FERC's Order 888 direct allocation approach;
- the California competitive transition charge/rate reducing bond approach;
- the Rhode Island fixed surcharge; and
- the aborted South Carolina Electric & Gas Co. transmission loading formula.

Many other states are in various stages of considering the issue.

FERC Order 888 Provisions on Wholesale Stranded Cost Recovery

Issued April 24, 1996, FERC Order 888[49] requires the direct assignment of cost obligation to wholesale customers leaving a given transmission system. (FERC's primary authority is limited to wholesale transactions.) Using the revenues lost formula, an amount is determined and allocated to the departing party. FERC holds that it is the responsibility of the party that has caused the cost to be incurred under a regulated market that should bear the burden of repayment as the market makes the transition into competition. Order 888 accomplishes this by levying an exit fee on wholesale customers that can now leave or bypass a transmission system in order to buy cheaper power supplies elsewhere.

Another option that FERC considered by was to increase the delivered price to an entire region with a wires charge. However, this method is not considered to be in the best interest of the public. Under U.S. federal law, a broader surcharge could be considered a tax, and FERC does not have legal authority to raise taxes. The U.S. Department of Justice states that a transmission adder is analogous to an excise tax that would distort pricing signals and customers' decisions on the use of electric power. It submits that the lump sum approach, on the other hand, would establish a fixed, sunk liability that would not depend on how much transmission service the departing customer takes in the future.

FERC has stated that it will strictly regulate on the wholesale level and only become involved on the retail level when a state regulatory agency lacks authority to address retail stranded costs.

Order 888's exit fee approach ensures that captive customers do not pay for the recovery of stranded investments. Those customers who could leave the system to buy cheaper power elsewhere are dissuaded from doing so by the exit fees they would incur.

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[49] Order No. 888 can be found on the Washington International Energy Group web site at http:\\www.wieg.com under electric and gas sector, restructuring background.

California Electric Utility Restructuring Law

The California electric utility restructuring legislation[50] was signed into law on September 23, 1996. With this law, utility rates will be capped at their current level until the year 2001. Beginning in 1998, residential and small commercial customers will receive a 10 percent rate cut, to be financed through the issuance of rate reduction bonds by the California Infrastructure Development Bank.

The law also provides for utility stranded cost recovery through a non-bypassable, usage-based, competitive transition charge (CTC) for distribution service. The CTC will appear on the customer's bill as a separate item. Costs must be recovered by December 31, 2001, with the exception of some specific categories. The CPUC will determine which generation costs and obligation categories can be recovered. These are likely to include generation facilities, generation-related regulatory assets, nuclear settlements, power purchase contracts, and personnel costs from further downsizing.

The CPUC is required to establish an effective method of collecting transition costs from all existing and future consumers in a given utility service territory as of December 20, 1995. Transition costs are not recoverable from new customer load. Although the law prohibits cost shifting, some entities have obtained exemptions from obligations to pay a CTC. These exemptions do not mean that the amount of the CTC will be reduced, but will instead be shifted to other customers.

Nuclear decommissioning costs are not part of the uneconomic costs but are recoverable as part of the non-bypassable CTC charge. Decommissioning costs must be recovered in the same time frame, beginning in 1997 and concluding in 2001. Public power must follow the same rules to recover stranded costs.

California has begun to identify its stranded investment and translating those numbers into rates to be applied beginning January 1, 1998. The

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[50] A.B. 1890 can be found on the Washington International Energy Group web site at http://www.wieg.com under electric and gas sector, restructuring background.

initial filing of the three IOUs in California produced a cumulative amount of stranded investment equaling approximately $28 billion.

Following the submission of stranded investment numbers by the Californina IOUs in late October 1996, the California Public Utility Commission will proceed by launching Phase I of a three-phase process this year. Briefings for Phase I are to begin the end of January 1997, outlining the terms and conditions of the CTC, CTC exemptions, and details associated with the creation and maintenance of the transition cost balancing account.

Phase II will focus on the factual and policy underpinnings of the quantitative aspects to establishing transition costs. The second phase is scheduled to begin in mid-March with an independent outside firm audit of stranded investment figures.

Rhode Island Utility Restructuring Act of 1996

The Rhode Island Utility Restructuring Act was approved by a unanimous vote of 93 to 0 in the state House of Representatives on June 11, 1996. On August 1, the state Senate followed suit with a vote of 38 to 6 and on August 7, the Governor signed the act into law. This act brings competition to the state's electric utility industry and allows customers to choose their electricity supplier. It is expected that Massachusetts will adopt essentially the same law, and variations will also be adopted by other New England states. The key element in the law is a 2.8 cents per kilowatt hour broad-based surcharge on all customers that will be in effect for 12.5 years.

It will be phased in beginning July 1, 1997, when new customers over 200 kilowatt (kW), existing customers over 1,500 kW, and all state accounts will begin to have choice. On January 1, 1998, all manufacturing customers over 200 kW and all municipals will have choice. And finally, on July 1, 1998, all remaining customers will have the option to select their supplier. However, if 40 percent of the New England region receives customer choice before July 1998, a clause has been included that gives all Rhode Island customers choice within the six months following, regardless of the present timetable.

As is the case in California, Rhode Island and other New England states have relatively high-cost electricity. Combined with the boom-bust economic history of the region, it is easy to forge a strong political consensus in favor of reducing electricity costs. This legislation was the first of its kind in the United States. Its intention was to address the transition to a competitive industry while still addressing utilities' past commitments.

The legislation requires:

- "functional unbundling" of generation, transmission, and distribution
- deregulating generation, and
- allowing market-based commodity pricing.

Transmission will remain regulated by FERC, and utilities must provide open access to their transmission systems. Distribution will continue to be regulated under Rhode Island State jurisdiction. Although they will be functionally separated, the legislation allows for the sectors to remain in the same corporate "family" and provides standards of conduct to be implemented among the affiliates.

Once competition is established, utilities will continue to provide "standard offer" rates consistent with what is provided today for the duration of the transition period. Distribution rates will increase for customers electing to stay with bundled service between 1997 and1999, but be held to the level of inflation. Low-income customers will be exempt from this increase. The law states that there will be no cross subsidies between customer classes.

All utilities recovering stranded investments via transition charges are required to determine the market value of their generating assets through the sale, lease, or spin-off of some portion of their hydro or fossil assets. This determination is to be accomplished through a market valuation methodology to be selected by the wholesale power supplier for all of the generating group, part of the generating group, or each generating facility individually. The requirement states that at least 15 percent of the generating ownership interest must be sold, leased, spunoff, or otherwise disposed.

Once the wholesale supplier has determined the percentage of generating assets it will divest, the company will develop an implementation methodology that is reasonably likely to approximate market value of the generation assets. The commission will approve the methodology for the approximation of market value and a stranded investment total will be deducted from this amount.

Massachusetts and New England Electric System have agreed to an identical approach. Other states in the region in which New England Electric maintains a significant presence are likely to adopt key elements in the Rhode Island law. The New England approach is being carefully watched by the North American electric utility industry. In contrast to California, where the CTC is not defined, the combination of a fixed recovery fee and a must-sell provision provides both an element of certainty as well as some flexibility.

South Carolina Electric and Gas Company

On August 6, 1996, SCE&G, a wholly owned subsidiary of SCANA Corporation, filed a proposal with FERC to transfer approximately $257 million in transmission and distribution depreciation asset reserves of the VC Summer nuclear station assets. By transferring the depreciation assets, the net book value of the nuclear generating facility would be reduced by $257 million, the value of the transmission plant would be increased by approximately 25 percent, and the value of the distribution plant would be increased by the approximately 75 percent remaining. The proposal would change the rates in SCE&G's wholesale tariff and its open access compliance tariff, increasing wholesale rates by an average of approximately 19 percent[51] in the undiscounted rate for basic transmission service and creating a net reduction in the overall revenue requirement for bundled wholesale sales.

In January 1996, the South Carolina Public Service Commission approved the transfer for the purpose of establishing SCE&G's **retail** rates. The South Carolina Commission found that, for the purposes of retail ratemaking, the generation, transmission, and distribution effects would be "offsetting" and without a "material effect on the rates."[52] Observers noted at the time that

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[51] SCE&G estimate, FERC Order Rejecting Rate Filing and Requiring Corrected Book Entries, Docket Nos. ER96-2637-000 and FA96-49-000, p. 2 (Exh. No. ___ (WWL-1) at 11).

[52] Overall rates were proposed to change by approximately 3.5 percent for wholesale customers. FERC Order Rejecting Rate Filing and Requiring

this decision seemed to be a way of encouraging economic investment and protecting existing utilities in the state by shifting the cost of recovering nuclear expenses to "outsiders" trying to enter the state to sell electricity.

However, on September 23, 1996, FERC denied the proposal to change the **wholesale** tariff stating the following reasons:

- The proposal does not assign costs according to FERC Order 888 cost causation principle, but indiscriminately apportions cost over all transmission and distribution customers.

- The calculation proposed by SCE&G for assessing stranded costs is based on net investment in excess of regional average net investment in nuclear facilities, rather than on the loss incurred by a departing customer as Order 888 lays out.

- Direct assignment of costs as in Order 888 leads to more accurate costing; SCE&G's proposal is based on preventing **potential** stranded costs.

- The broad-based approach places a surcharge on transmission that could be an inefficient cross subsidy reducing beneficial power trading.

- A depreciation reserve transfer would place costs on all customers regardless of contracts that may have prohibited stranded cost recovery, and even on those who may never have been a power sales customer of SCE&G.

In reaching this decision, which is subject to court challenge by SCE&G, FERC for the first time affirmed that on the wholesale level it intends to enforce its direct causation principle and will not conform to state decisions involving burden shifting. The impact of this precedent is to prohibit utilities from loading stranded costs into their transmission rates if wholesale transactions are involved. In practical terms, breaking down the distinction between transmission and distribution will potentially obviate the ability of

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Corrected Book Entries, Docket Nos. ER96-2637-000 and FA96-49-000, p. 2 (Exh. No. ___ (WWL-1) at 9).

state commissions to set transmission loading regulations and avoid jurisdictional conflict with FERC.[53]

Other State Perspectives

Individual state reaction to stranded investment burdens and the toll it could take on state economies has been quite varied. Many states have not issued policies yet and may not until retail choice becomes a more eminent reality. The following states have begun examining the extent to which stranded investment will play a role in an unfolding competitive environment:

Alabama: A May 1996 law requires the Public Service Commission or court to review contracts of retail customers leaving a system and contracting for new power supplies, to determine if the contract is in the public interest and to allow full stranded cost recovery for the utility.

Connecticut: Utilities are entitled to full recovery of non-mitigatable stranded investment with the understanding that mitigation efforts need to be monitored.

Maine: The Maine Public Utility Commission had proposed allowing only 50 percent stranded cost recovery from former retail customers becoming wholesale customers of another utility. The proposal was withdrawn, however, Central Maine Power has requested reopening the proceeding.

Maryland: The Public Service Commission found that retail competition was not in the public interest at this time stating that, among other things, stranded cost issues need to be resolved.

Michigan: In an order approving retail wheeling experiments, Michigan is permitting 100 percent recovery of certain regulatory assets.

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[53] A very important issue is the redefinition of "transmission" and "distribution" since retail access tends to erase the distinction. The Schaefer bill, H.R. 3790 introduced in the 104th Congress, would require FERC to undertake a major survey and adopt a rule redefining the terms to accommodate the full impact of customer choice.

New Hampshire: The New Hampshire Public Utility Commission claims that there is no legal right for full recovery of prudently incurred costs. The retail wheeling pilot program allows for 50 percent recovery with higher amounts subject to negotiation.

New Jersey: Revenue reductions from industrial discounting can be recovered from other customers provided certain criteria are met.

New York: Utilities and IPPs should have an opportunity to recover prudent and verifiable stranded investments according to the Public Service Commission. Prudent, verifiable, and non-mitigatible stranded costs may be recovered through a non-bypassable wires charge. Amount and timing will be determined in individual utility restructuring filing.

Pennsylvania: New restructuring legislation has been enacted. Stranded cost recovery will be done on a utility-by-utility basis.

States' public utility commissions continue to struggle to balance customer and shareholder needs and become competitive. As each state drafts and implements legislation, other states listen and learn from those experiences.

The Impacts of the Department of Energy's Nuclear Waste Program on Existing Nuclear Power Plants

The History of the Program

As mentioned in Chapter II, we do not believe the waste situation in itself will cause an owner to shut down a facility. Rather, we have concluded that when combined with other problems, running out of storage may influence an owner's decision to shut down a facility.

The Nuclear Waste Policy Act (NWPA) of 1982, as amended, required DOE to characterize Yucca Mountain and other sites to determine if they were adequate sites to dispose of spent nuclear fuel. This requirement has been controversial since the Congress designated Yucca Mountain as the sole site for that purpose in 1987. The state of Nevada did not feel that the process which led to that outcome was fair and consequently utilized every delaying tactic at its disposal for several years. The original delays centered on granting permits that were required by law to initiate certain activities.

When the courts finally ruled in favor of the federal government, allowing it to proceed with characterization activities, the program had already been delayed for several years. The project was also far more complex from a scientific and engineering perspective in addition to being more costly than originally projected.

NWPA envisioned that DOE would open a permanent repository in 1998. It also required DOE to determine if a temporary facility should be constructed. DOE's recommendation that such a facility be constructed in Tennessee was rejected by the Congress, and a voluntary siting initiative was substituted. That effort, which was supposed to entail a voluntary negotiation between an interested state, locality, or Indian tribe and the federal government, was also killed by members of Congress or officials who represented a state or locality that had expressed some interest in hosting such a facility.

Other factors, in addition to cost overruns and schedule delays, were coming to the fore and further politicized the program. First, Northern States Power Company's Prairie Island plant, located in Minnesota and one of the nation's best facilities, was running out of on-site storage. This situation led to an extremely controversial process in the early 1990s which ultimately granted the company the authority to add dry storage. Early in the process, an administrative law judge recommended that the commission not grant the company's request on the grounds that the site would ultimately become a permanent repository due to the federal government's lack of progress in constructing a repository. It was becoming understood by utilities, their commissions and those in the Congress who paid attention to the program that DOE would probably fail to take title to spent commercial fuel by 1998 as agreed. The approval granted to Northern States to add additional on-site storage was conditioned on the company doing several things, some of which were expensive.

At the same time, many other affected parties were voicing dissatisfaction with the program. The state commissions representing the jurisdictional ratepayers financing the program expressed concern that the funds contributed by their constituents were not producing results leading to the construction of a repository. States would be confronting the same problem as those in Minnesota and with the same political ramifications. Additionally, following the visible Northern States situation, other utilities with less imminent problems began to pay much closer attention to the waste program.

Funding Controversy

Another controversy in the nuclear waste program was the funding mechanism. The Nuclear Waste Policy Act of 1982, as amended in 1987, requires customers of utilities owning nuclear power plants to pay a fee on each kW of electricity generated by nuclear plants. The funds were supposed to finance the programmatic activities authorized by the waste act and, ultimately, the costs of repository and Monitored Retrievable Storage (MRS) construction. Even though the program was funded by a dedicated source of revenue, the Congress appropriated funds every year for waste management through the normal appropriations process. The Congress never funded the program at the amounts contributed by the ratepayers. It was more typical for the ratepayers to contribute $600 or $700 million dollars per year and for the Congress to appropriate approximately 50 to 70 percent of that amount. By the end of 1995, ratepayers had contributed $7.5 billion to the program, $9.4 billion when interest is factored in. Only $4.6 billion has been appropriated for programmatic activities.

This situation may have been politically acceptable if progress were being made which would have led to the construction of necessary facilities. Many state commissions and affected utilities also began to argue that they were paying twice for waste storage. They did so once through the statutory requirement and the second was when many would be required to pay to add new on-site storage. DOE proposed several mechanisms that would have increased program funding over the last four years. None of these proposals were accepted by the Congress. Congress provided the funding only in FY 1995 that DOE requested for the civilian nuclear waste program.

Lack of Consensus in the Path Forward

The funding controversy, combined with a lack of progress, greatly increased the political controversy surrounding the program. The major affected parties (nuclear utilities, state commissions, other elected state officials) never were united as to how to proceed. Some states advocated that their jurisdictional utilities stop paying into the Nuclear Waste Fund.

Others wanted their ratepayers' money back. It is not clear whether the program could have survived had either of these things happened. Others advocated constructing a temporary above ground facility in order to begin moving waste. Such a strategy would have further delayed the construction of a permanent repository. Nobody expected the Congress to fund two large construction projects in DOE at a time when its budget was being reduced.

After passage of the Nuclear Waste Policy Act Amendments of 1987, DOE signed contracts with owners of nuclear plants to begin accepting waste in 1998. In recent years, it has became evident that DOE will not be able to abide by those contracts. Every energy secretary who grappled with that problem asked the age-old question, where can I put the waste? When the original contracts were signed between DOE and utilities, it was believed that facilities would be in operation and able to accept the waste. DOE's General Counsel and the independent General Accounting Office (GAO) concluded that the department was not at legal risk for failure because facilities authorized by the Nuclear Waste Policy Act were never constructed. This year the United States Court of Appeals ruled on a lawsuit brought by 38 utilities and 28 states that DOE did have a legal obligation to accept waste, and required it to develop a plan to achieve that goal. DOE has stated that it requires additional statutory authority to live up to the court order.

Current Efforts

Some may wonder what the Congress has been doing to respond. For the past several years the Congress would fund the program at approximately 50 to 70 percent of the requested amount and voice its collective concern with the lack of progress in developing a repository. Only in the last Congress was a genuine attempt made to amend the waste act and authorize the construction of an interim facility in Nevada. Currently, a provision in the act prohibits the construction of an interim facility until a license application has been made to construct the repository. The attempt to require DOE to construct an interim facility failed for several reasons. First, the President was opposed to the legislation. He committed to oppose any legislation which singled out Nevada as the site for an interim storage facility, without some process which concluded that this was an appropriate location for such a facility. Additionally, some in the administration were concerned that an interim facility would preclude the United States from living up to its national security responsibilities. Since the late 1970s, the nation has committed itself not to reprocess any fissile material currently in its possession and to permanently dispose of such material in a repository. Currently, DOE is the custodian of a large amount of weapons grade material stored at former weapons production facilities. Those in the administration with responsibilities were concerned about the signal that a temporary facility would send to the international community; thus, they continued to support the ongoing work at Yucca Mountain.

The future direction of nuclear waste policy is no more clear than this description. When the Congress had authorized over $500 million in FY 95 there was hope that the program would make real progress. The program had targeted 2010 for emplacing waste in a repository. However, this was dependant upon the Congress agreeing to provide DOE with large funding increases. By 1996, it was back to business as usual; the Congress provided $400 million dollars to the program whereas DOE requested $630 million. Furthermore, the Congress directed DOE to spend $85 million on an interim storage facility which was dependant upon new statutory authority. Thus, only $315 million was available to continue work at Yucca Mountain—only 50 percent of DOE's request.

The funding was accompanied by new programmatic direction. The language accompanying the funding directed the program to only pursue the core scientific activities at the site. The program's plan with greater funding was to evaluate the site for its suitability as a repository by 1998, deliver a recommendation to the President on the site's suitability to be a repository and an Environmental Impact Statement (EIS) by 2000, submit a license to the NRC by 2001, receive acceptance by 2004, and open the facility in 2010. The Congressional direction was dramatically more limiting than the direction DOE was pursuing. Specifically, DOE had developed an elaborate public participation process and wanted its scientific work to be peer reviewed by the National Academy of Sciences. Congressional guidance and funding required that this work not go forward and filing of the license application was deferred. In response to this direction, a revised program approach was issued in draft in May 1996.

The program is still committed to opening a repository by 2010, 12 years later than originally intended. The revised plan commits DOE to address by 1998 the remaining technical questions regarding the site and the scientific, engineering and financial viability of constructing the repository. Whereas the earlier program was geared toward determining the suitability of the site, the revised approach will seek to make a viability finding. The new program is designed to provide the President with a repository site by 2000 and apply to NRC for a license by 2002 for repository construction. Surprisingly, the strategy contemplates designating an interim storage facility in 1999 and accepting waste at such a facility in 2002, a strategy that would require authorizing legislation.

Opening a repository in 2010 may be unlikely. DOE's effort to open a repository by 2010 makes several assumptions. First, it assumes significant streamlining of DOE's siting rules and that the EIS process will not be delayed—a rarity with any project, but particularly with a project of this magnitude. It also assumes the state of Nevada will not be able to further delay the process. It is possible that the Congress will pass interim storage legislation and such a facility can ultimately be built. There are no technical problems in above-ground storage of commercial waste. Yet, as was seen last year, passage of such legislation will be extremely contentious. If such a facility were developed, and waste was moved, the states and affected utilities would have certainty that waste would not be stored on-site in perpetuity and limit controversy if they needed to add new storage.

For all of these reasons, we are not counting on the option of shipping waste off-site in the near future. It will be necessary to construct on-site storage facilities, or, in a few instances, facilities at another site owned by the same utility to have storage space over the next decade—the period covered by this study.

CHAPTER VI—UNCERTAINTIES OF THE STUDY AND DEVELOPMENTS TO WATCH

Uncertainties

- This analysis was at the macro level, that is, reliance was primarily placed on publicly available information. It provides a very good guide to sites and their owners that are vulnerable to shutdown. The next step must be to perform rigorous investigations of these sites.

- By the time published data are available, they are already somewhat dated. Individual company reports are needed to ensure more timely information and validate it.

- A more complete study would compare the costs and viability of all fuel types. Even though a nuclear site may be found vulnerable by this study, other generating units owned by the same company may be more vulnerable to shutdown. If so, there may be a resistance to shut down a nuclear facility.

- The market and pricing system for electricity is yet to be worked out. We only know that past prices are not a good guide to the future. The market model used for this study simulates future markets. By default, it assumes a smooth transition to the competitive era. In reality, there is likely to be considerable chaos in markets and prices for much of the period that this study covers. The model provides a reasonable direction in which prices may go, but not year-to-year equilibrium prices.

- Owners of nuclear power facilities can potentially take other actions that enhance revenue. If capacity is available, they can attempt to sell capacity to others. This is arranged to cover an agreed upon amount of capacity, in megawatts, over a certain time period. They might also sell electricity on the newly developed futures market. In this instance, the transaction is energy, that is kWh. Such sales can earn net revenues if the futures price is higher than the marginal cost of generation, which for nuclear facilities is very low. Another strategy that nuclear facilities can use is to sell as much of the annual output at peak periods—the summer and winter—as possible. Peak prices are usually substantially higher than off-peak prices. To do this, refueling and other planned outages would need to be done in the off-peak seasons—spring and fall.

- Even though stranded investment costs are not a primary determinant of the failities' market value, the process by which these are recovered may cause the nuclear facility to shut down or continue operation. In the past when state agencies—or in one case a municipal—wished to close a nuclear plant, recovering the remaining capital investment was a part of the arrangement. If similar approaches are adopted, the site will be closed regardless of its potential future value.

Developments to Watch

In addition to individual plant performance, the following will be especially important to decisions on shutdown.

- Whether any of the licensees requiring license renewal in the next 10 to 12 years will proceed with an application in the next year or two. If none are received in the next one to two years, it is improbable any will be later. NRC could decide on yet a third rulemaking to devise an approach that at least some licensees would find attractive. It would be an extreme situation if all nuclear plants closed at the end of the current license.

- NRC is proposing stringent requirements for ensuring funds to be available for decommissioning in a market environment. It is difficult to envision financial mechanisms e.g., surety bonds, of the magnitudes needed to provide the anticipated requirements. Although this requirement may not greatly affect the short term costs of the facilities, it would certainly affect the value of the facility in cases of mergers and acquisitions.

- There may be legislative relief to ensuring decommissioning and decontamination costs; however, none has progressed very far. In the 104th Congress, former Senator Johnston introduced S. 1526, The Electricity Competition Act of 1995, which called for federal funding. It was not enacted. In the same session, Congressman Schaefer's H.R. 3790 Electric Consumers' Power to Choose Act of 1996, called for the states to deal with decommissioning funding. Congressman Schaefer is planning renewed effort on electricity restructuring legislation in this session.

- Congressional action or inaction on waste storage will eventually affect the viability of some sites. As in the case of Prairie Island, local opposition to any on-site solution can cause severe distress to the company and may lead to plant shutdown.

TECHNICAL ANNEX ON THE MARKET MODEL

Source of Price Forecasts and Assumptions

With the change from a regulated industry to a market-oriented industry, it is unsatisfactory to project future prices based on past ratemaking by PUCs or other governmental jurisdictions. Therefore, we used a technique to derive price forecasts presuming a competitive environment. We chose a study entitled, *North American Bulk Electric Market Forecasts (1997-2010)*, provided by IREMM, Inc.[54] This is a dynamic simulation model that provides price forecasts under varying input assumptions of production costs, electric generation capacity, and growth in demand. The model simulates prices and sales for each set of input assumptions. In the competitive market underlying the model, customers may purchase from any supplier and the supplier may sell to any customer, subject to there being adequate transmission between the buyer and producer. We believe that the situation will increasingly be the case over the period of the study—the present through 2005 and beyond.

The model simulates the operation of nearly 9000 electric generating units in the U.S. and Canada for 119 separate "market areas." These market areas are largely determined from traditional load forecast reporting systems: control areas, power pools, or other administrative grouping of companies. The defined market areas in this study vary widely but are all subdivisions of theNERC regions. The largest the market area is a NERC region, for example, MAAC. In other cases it is defined by a single utility, for example, Consumers Power, a Michigan utility. All utilities of concern to this study are included in one of the market areas defined. They are shown in Appendix Table 2.

Even though prices are simulated by market area, the model assumes a competitive market throughout the U.S. and Canada. The basic assumption

[54] "Used by permission of IREMM, Inc. (860) 738-1252. All rights reserved."

or "base case" is that there are three interconnected areas covering all of the two countries where all suppliers must compete for customers. These are:

- Eastern Interconnection System
- Western Interconnection System
- Electric Reliability Council of Texas (ERCOT)

In this model, all electric generating companies compete in one of these three markets. This is described as a new paradigm for the electric utility industry. Providers will operate in a market where **prices are set by someone's costs somewhere**, but such costs are not necessarily either those of the buyer or seller. For example, the bulk power market for American Electric Power (AEP) consists of all of the companies in the Eastern Interconnection System. Many of these companies will be too distant to make frequent direct transactions with customers in AEP's market area feasible, but they will influence AEP's market indirectly by affecting the purchase and sales opportunities of its neighbors. An interconnected market does not mean a single price. There are still differences among the defined market areas within the interconnection.

Prices developed are for the bulk power market, a level at which strong market incentives are presumed. Producers are presumed to make every sale (if a customer can be found) that contributes to fixed costs—that is variable costs are covered and some revenue is available to contribute to fixed costs. Generating units are presumed to be brought on-line by the effective operation of dispatch centers that select generating units as suppliers of the next sale according to the one that has the lowest variable production costs. A unit's variable cost of production is based on the cost of fuel, the unit's heat rate, and the unit's incremental operation and maintenance costs.

IREMM incorporates projections of capacity additions and future loads from industry and NERC information as reported by DOE, Form OE-411, 1995 and 1996. Capacity additions and retirements are taken from the NERC forecasts as reported on Form OE-411. Electricity demand is developed for each market area based on company or power pool forecasts from information on OE-411 monthly load forecasts, 1996. The load duration curves from OE-411 are divided into three blocks. The highest one-third is called peak demand, the lowest one-third is off-peak, and the middle one-third is called mid-peak demand. Prices are simulated for each of the three parts of the load curve. The model has a built-in assumption that

Maine Yankee, Connecticut Yankee, and Millstone, as well as Bruce "A", a Canadian nuclear unit, will close down due to license expiration.

In addition to the "base case" there are 13 different cases (or scenarios) provided by IREMM, are other cases that are variations on such items as fuel availability, hydro availability, and nuclear availability. One case assumes that there will be a firm interconnection between the Eastern Interconnection System and ERCOT.

How the Simulation Model Was Used for the Market Analysis

For this study, we initially considered three of the cases:

- the base case;
- compared with the base, ten percent of the nuclear capacity is shut down; and
- Eastern Interconnection System and ERCOT have a firm interconnection.

There were rather small differences in market clearing prices among these three cases. Therefore, any of them would result in approximately the same conclusions on the ability of nuclear sites to compete in their market. Long-range forecasts are quite uncertain at best and therefore, at the level of precision that is meaningful, there is little value in pursuing all three cases. We selected the case of a 10 percent nuclear shutdown because there is likely to be at least this much nuclear capacity shut down. Recall that the model already assumes that Maine Yankee, Connecticut Yankee, and Millstone Unit 1 are shut down due to license expiration, so that this case assumes a shutdown of about 12 percent of the nuclear capacity.

Some important features of the model are the following:

- Individual market areas are dispatched using native resources first.

- Supply and demand curves are developed which reflect each market area's willingness to buy or sell at various price levels.

- Wheeling costs are incurred when third-party transmission systems are used for sales between market areas. These costs may make some transactions uneconomical.

- A minimum contribution-to-fixed cost margin, and a minimum savings before purchase, must be realized before a transaction is consummated.

- Auctions of surplus energy by sellers to the highest bidders determine a free-market price.

- Separate analysis is conducted for on-peak, mid-peak and off-peak periods.

- Several transmission interfaces constrain energy flows between regions and limit transactions.

- Impacts of individual generating operating characteristics are considered on a technology-specific basis.

- Fixed costs (sunk or embedded costs) are not included in the development of the market clearing prices.

The base case scenario is for an Eastern Interconnected System, a Western Interconnected System, and an isolated ERCOT system. One of the alternative scenarios is for ERCOT and the eastern system to be interconnected. This is the scenario that we use as our analysis. Features are as folows:

- Prices rise consistent with general inflation, rising fuel costs, and falling reserve margins.

- Reserve margins fall as utilities attempt to avoid building new generating facilities, there is an increase in the use of existing resources, and supplementing is done with strategic purchases and sales of power.

- Construction of new units lag because producers are reluctant to add new resources without a guaranteed return on investment, and such assurances are no longer forthcoming. Furthermore, new construction is impeded in the near term by a perception of continued excess capacity overall.

Alternative scenarios include alternative assumptions of load growth, fuel prices, changes in nuclear capacity up and down, transmission wheeling rates, and hydo capacity (western interconnection only).[55]

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[55] Drawn from *North American Bulk Electricity Market Forecasts (1997-2010), op. cit.,* October 1996, pp. 1-1 to 1-5, 3-3 to 3-6, B-1 to B7, and C-1.

Appendix Table 1
COMPARISON OF PUBLIC CITIZEN'S
LEMONS AND WASHINGTON INTERNATIONAL ENERGY GROUP'S
POOR PERFORMERS, see Chapter I

The two lists were derived from entirely different perspectives, the Washington International Energy Group's considers non-fuel O&M costs and output performance. Public Citizen derives theirs by counting various safety occurrences at individual nuclear units.

Lemons	Poor Performers
Salem 1 & 2	Salem 1 & 2
WNP 2	WNP 2
Millstone 1 & 2	Millstone 1 & 2
River Bend	
Dresden 2 & 3	Dresden 2 & 3
Quad Cites 1 & 2	Quad Cities 1 & 2
Sequoyah 1 & 2	Sequoyah 1 & 2
South Texas 1 & 2	
Perry	
Cooper	Cooper
LaSalle 1	
Fitzpatrick	
Fermi	Fermi
Haddam Neck*	Haddam Neck*
Indian Point 3	Indian Point 3
	Indian Point 2
Palisades	Palisades
Brunswick 1	
Pilgrim	Pilgrim
Zion 1	
	Browns Ferry 2
	Oyster Creek
	Hope Creek

*a.k.a. Connecticut Yankee

Appendix Table 2

MAJORITY OWNER, IREMM MARKET AREA
AND NERC REGION FOR EACH NUCLEAR SITE[56]

Site	Majority Owner	IREMM Market Area	NERC Region
Conn. Yankee	Northeast Utilities	NEPL	NEPOOL
Millstone 1 & 2	Northeast Utilities	NEPL	NEPOOL
Millstone 3	Northeast Utilities	NEPL	NEPOOL
Seabrook	Northeast Utilities	NEPL	NEPOOL
Maine Yankee	Maine Yankee Atomic	NEPL	NEPOOL
Vermont Yankee	Vermont Yankee Nuclear	NEPL	NEPOOL
Pilgrim	Boston Edison	NEPL	NEPOOL
Ginna	Rochester Gas & Elec.	UPNY	NYPP
Nine Mile Point 1	Niagara Mohawk	UPNY	NYPP
Nine Mile Point 2	Niagara Mohawk	UPNY	NYPP
Fitzpatrick	New York Power Authority	UPNY	NYPP
Indian Point 3	New York Power Authority	UPNY	NYPP
Indian Point 2	Consolidated Edison	SENY	NYPP
Calvert Cliffs	Baltimore Gas & Electric	MAAC	MAAC
Limerick	PECO Energy	MAAC	MAAC
Peach Bottom	PECO Energy	MAAC	MAAC
Three Mile Island	GPU Nuclear	MAAC	MAAC
Oyster Creek	GPU Nuclear	MAAC	MAAC
Susquehanna	Pennsylvania Pwr. & Light	MAAC	MAAC
Hope Creek	Publ. Serv. Elec. & Gas	MAAC	MAAC
Salem	Publ. Serv. Elec. & Gas	MAAC	MAAC
DC Cook	Indiana Michigan Power	AEP	ECAR
Fermi	Detroit Edison	DECO	ECAR
Big Rock Point	Consumers Power	CP	ECAR
Palisades	Consumers Power	CP	ECAR
Beaver Valley	Ohio Edison	CAPC	ECAR

[56] For comprehensive information on ownership of nuclear plants and interrelationships among parent companies and subsidiaries, see *Owners of Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, NUREG/CR-6500, ORNL/TM-13297, November 1996.

Davis Besse	Centerior Energy Corp.	CAPC	ECAR
Perry	Centerior Energy Corp.	CAPC	ECAR
Brunswick	Carolina Power & Light	VACR	SERC
Harris	Carolina Power & Light	VACR	SERC
Robinson Two	Carolina Power & Light	VACR	SERC
Catawba	Duke Power	VACR	SERC
McGuire	Duke Power	VACR	SERC
Oconee	Duke Power	VACR	SERC
Farley	Southern Nuclear Oper.	SOUT	SERC
Hatch	Southern Nuclear Oper.	SOUT	SERC
Vogtle	Southern Nuclear Oper.	SOUT	SERC
North Anna	VEPCO	VACR	SERC
Surry	VEPCO	VACR	SERC
Summer	South Carolina E&G	VACR	SERC
Turkey Point 3 & 4	Florida Power & Light FLA		SERC
St. Lucie	Florida Power & Light FLA		SERC
Crystal River	Florida Power Corp.	FLA	SERC
Browns Ferry	TVA	TVA	SERC
Sequoyah	TVA	TVA	SERC
Braidwood	Commonwealth Edison	CECO	MAIN
Byron	Commonwealth Edison	CECO	MAIN
LaSalle	Commonwealth Edison	CECO	MAIN
Dresden	Commonwealth Edison	CECO	MAIN
Quad Cities	Commonwealth Edison	CECO	MAIN
Zion	Commonwealth Edison	CECO	MAIN
Kewaunee	Wisconsin Pub. Service	WUMS	MAIN
Point Beach	Wisconsin Elec. Pwr.	WUMS	MAIN
Clinton	Illinois Power	SCIL	MAIN
Callaway	Union Electric	EMO	MAIN
Monticello	Northern States Power	MAPP	MAPP
Prairie Island	Northern States Power	MAPP	MAPP
Duane Arnold	IES Utilities	MAPP	MAPP
Fort Calhoun	Omaha Publ. Power Dist.	MAPP	MAPP
Cooper	Nebraska Publ. Power Dist.	MAPP	MAPP
Arkansas One	Entergy Arkansas	SPPS	SPP
Grand Gulf	Entergy	SPPS	SPP
River Bend	Entergy Gulf States	SPPS	SPP
Waterford 3	Entergy Louisiana	SPPS	SPP

Wolf Creek	Kansas City Pwr. & Light	SPPN	SPP
Comanche Peak	TU Electric	ERCO	ERCOT
South Texas	Houston Light & Power	HL&P	ERCOT
Palo Verde	Arizona Public Service	APS-AZ	WSCC
Diablo Canyon	Pacific Gas & Electric	PG&E	WSCC
San Onofre	Southern Calif. Edison	SCE	WSCC
WNP 2	WPPSS	BPA	WSCC