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Replacement Energy Costs for Nuclear Electricity-Generating Units in the United States: 1997 – 2001

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Argonne National Laboratory

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ABSTRACT

This report updates previous estimates of replacement energy costs for potential short-term shutdowns of 109 U.S. nuclear electricity-generating units. This information was developed to assist the U.S. Nuclear Regulatory Commission (NRC) in its regulatory impact analyses, specifically those that examine the impacts of proposed regulations requiring retrofitting of or safety modifications to nuclear reactors. Such actions might necessitate shutdowns of nuclear power plants while these changes are being implemented. The change in energy cost represents one factor that the NRC must consider when deciding to require a particular modification.

Cost estimates were derived from probabilistic production cost simulations of pooled utility system operations. Factors affecting replacement energy costs, such as random unit failures, maintenance and refueling requirements, and load variations, are treated in the analysis. This report describes an abbreviated analytical approach as it was adopted to update the cost estimates published in NUREG/CR-4012, Vol. 3. The updates were made to extend the time frame of cost estimates and to account for recent changes in utility system conditions, such as change in fuel prices, construction and retirement schedules, and system demand projections.

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FOREWORD

This report provides the U.S. Nuclear Regulatory Commission (NRC) with a capability to evaluate short-term replacement energy costs, including investigations into key sensitivities affecting these costs. These cost estimates were developed to assist in evaluating regulatory issues that potentially affect retrofitting or safety modifications of nuclear reactors.

NUREG/CR-4012 (Vol. 4) is not a substitute for NRC regulations, and compliance is not required. The approaches and/or methods described in this NUREG are provided for information only. Publication of this report does not necessarily constitute NRC approval or agreement with the information contained herein.

REPLACEMENT ENERGY COSTS FOR NUCLEAR ELECTRICITY-GENERATING UNITS IN THE UNITED STATES: 1997-2001

by

J.C. VanKuiken, K.A. Guziel, M.M. Tompkins, and W.A. Buehring

1 INTRODUCTION

1.1 BACKGROUND AND PURPOSE

This report provides updated information on replacement energy costs for short-term shutdowns of U.S. nuclear electricity-generating units. This information was developed to assist the U.S. Nuclear Regulatory Commission (NRC) in its regulatory impact analyses, specifically analyses that examine the impacts of proposed regulations that require retrofitting of or safety modifications to nuclear reactors. Nuclear power plants might have to be shut down while such changes are being implemented. The change in energy cost is one factor that the NRC must consider when deciding whether to require a particular modification.

The cost estimating procedures presented in this report were developed to update three previous studies that evaluated costs for fall 1984 through fall 1996 [1-3]. This update extends the time frame of the cost estimates through the year 2001 and accounts for changes that have occurred in utility systems since the previous estimates were made. The most significant changes have included updates in fuel prices, revisions to construction and retirement schedules, and modifications to system demand projections.

The term "replacement energy cost" refers to the change in the generating system production cost that results from shutting down a reactor. The change in production cost is the difference between the total variable costs (variable fuel costs, variable operation and maintenance [O&M] costs, and purchased energy costs) when the reactor is available for generation and when it is not. Changes in capacity expansion plans are not considered feasible responses to short-term shutdowns.

1.2 DEPARTURES FROM PREVIOUS ANALYSES

In previous evaluations [1-3], the replacement energy cost for each hypothetical reactor shutdown was determined from two sets of system dispatching and production cost simulations: (1) a case in which all units in a power pool, including the reactor of interest, operate normally and (2) a similar case in which all units operate normally except the reactor of interest, which is assumed to be unavailable for generation. To provide a consistent basis for comparison, a uniform set of assumptions (about key parameters such as load growth, fuel prices, expansion plans, and maintenance schedules) was used in both cases. Replacement energy costs were determined for each season on the basis of differences between the two simulations.

This study departs from previous analyses [1-3] in that an abbreviated analytical framework was used to update and project cost estimates. In terms of simulation methodology, the same system dispatching and production cost model as that used as the foundation for the analysis described in Reference 3 was used, but it was applied to only six of the 20 power pools containing reactors. The six power pools were chosen to maximize the number of reactors located in simulated power pools. Consideration was also given to obtaining representative samplings of capacity mix, generation mix, and regional fuel cost patterns.

The original intent of this current effort was to analyze trends in the cost estimates to identify key explanatory variables, then use these findings to (1) estimate costs for reactors in pools that were not simulated and (2) provide the NRC with a simple method for projecting costs in outlying years. The goal was to develop guidelines that would avoid the need to perform power-pool-specific simulations in future years.

However, simulation results revealed unexpected sensitivities to system dynamics and to interactions among more than one or two driving parameters. Examples of factors that affect replacement energy costs include system reserve margins, capacity and generation mix, unit retirements and additions, fuel switching, unit refurbishments, fossil and nuclear fuel prices, energy purchases and sales (including independent power production), planned and unplanned generator outage rates, system loads (annual and monthly profiles), and O&M costs.

Trends and changes in all of these parameters were traditionally accounted for explicitly in the system dispatching and production cost modeling efforts undertaken to develop the results reported in References 1-3. The analytical approach described in those reports, and briefly summarized in Section 2 of this report, was intentionally designed to recognize and simulate the interactions among all of the factors noted above. In the past, more abbreviated analytical methods were found to be unreliable and potentially misleading. However, the intent of this effort was to apply the detailed simulation methodology to selected power pools to provide reasonably reliable cost estimates for other power pools and for longer time projections.

The simulation outcomes were much less predictable than anticipated, revealing significant sensitivities to numerous factors as noted above and little or no consistency with regard to which parameters were most critical in each of the power pools. Because of the lack of simple trends or emergence of simple explanatory variables, the cost estimates summarized in Section 3 are presented as ranges rather than the simple adjustment factors that were originally planned to be applied to the more detailed 1992-1996 seasonal results reported in Reference 3. The cost ranges presented in this report are intended to capture variations in seasonal and annual results for simulated power pools and to encompass other estimation uncertainties for power pools that were not simulated.

The results shown in Section 3 include indications of the level of confidence assigned to cost results for each of 109 reactors expected to be in operation during the 1997-2001 time frame. Confidence is high for 59 reactors located in the six power pools that were simulated. For these reactors, the ranges of cost variation may be either large or small, depending on seasonal and annual variations revealed from the simulations. Results for the remaining 50 reactors are less certain, and the larger ranges of cost estimates reflect the uncertainties attributed to potential estimation errors in addition to those attributed to seasonal and annual variations.

1.3 ORGANIZATION OF THIS REPORT

Section 2 describes the approach used in this analysis and describes the data updates that were implemented. Section 3 displays the results and provides guidance for applying the cost estimates. Section 4 summarizes the findings. The appendix contains detailed outcomes for the six power pools that were used as the foundation for the cost estimates shown in this report.

2 METHOD OF ANALYSIS

This section briefly describes the modeling tools, data updates, and approximations that were used to estimate replacement energy costs for short-term reactor shutdowns. Only summary information is provided because this study incorporated many parameters. Reference 3 should be consulted for a more thorough discussion of basic methods and data references.

2.1 APPROACH

The fundamental simulation approach used in this analysis was identical to that used in each of the previous studies [1-3]. A dispatching and production-cost model was used to calculate the generation expected from each unit in the power pool and the associated costs of that generation. Determining reasonably accurate generation costs for a system of units with diverse characteristics requires the use of a simulation model because many complex factors influence costs. These factors include random forced outages of generating units, variation of system load over time, maintenance and refueling schedules, dispatching order, representation of generating units with a limited energy supply (e.g., hydroelectric units), and various practical system operating conditions.

Two modeling tools provide the basis for most of the analysis. One is the Investigation of Costs and Reliability in Utility Systems (ICARUS) model, which performs the dispatching and production-cost simulations for a particular generating system [4, 5]. The other is the Automated Data Assembly Package (ADAP), which contains data preparation tools and an extensive database of electric utility systems.

The ICARUS model probabilistically treats system load variations and unscheduled (forced) generating unit outages. Maintenance schedules (and reactor refueling schedules), heat rates, costs, and forced outages are considered independently for each unit. The model also includes representations for other operational criteria such as unit dispatching priorities and spinning reserves. Results obtained from the model include fuel consumption by unit and fuel type, energy generation by unit and fuel type, the corresponding fixed and variable costs, and reliability parameters such as loss-of-load probability and emergency purchases.

Further operational improvements were recently made to the modeling packages in an effort to provide a more menu-driven simulation environment. ICARUS and ADAP have been incorporated into the Argonne Production, Expansion, and Exchange (APEX) model that was developed for the U.S. Department of Energy (DOE) [6]. The APEX versions of these programs were used to facilitate this analysis.

In contrast to previous analyses, this abbreviated update does not include reactor-specific simulations for each of the 109 nuclear units. Instead, shutdowns of reactors located in six power pools were evaluated, and the simulation results were used to derive ranges of cost estimates for each reactor, reflecting seasonal and annual variations and other estimation uncertainties. The selection of the representative power pools is discussed in Section 2.2, and database updates are described in Section 2.3.

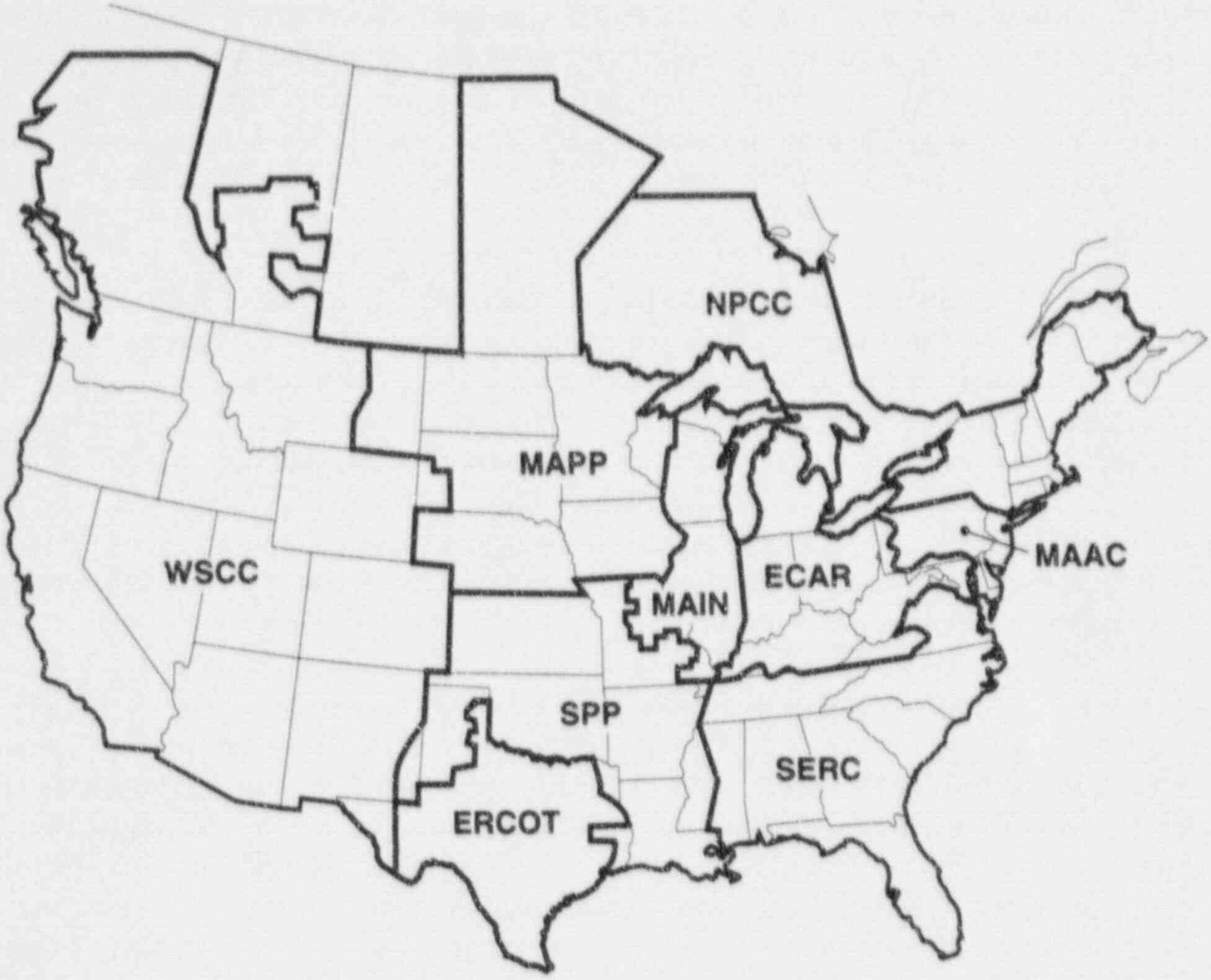
Initially, results were compared with previous outcomes from Reference 3. The intent was to establish simple cost multipliers that could be used to estimate new seasonal shutdown costs for each reactor. As indicated in the introduction to this report, trends were not uniform enough and relationships were not predictable enough to construct simple multipliers for each reactor. Replacement costs increased significantly in some pools and decreased significantly in others. While some of these variations were anticipated in advance, closer correlations were expected to occur between the outcomes and one or two parameters such as oil or gas prices. Because uniform patterns did not emerge from the analysis, the final cost estimates outlined in Section 3 are characterized as ranges rather than simple adjustment factors.

Another significant change with respect to previous analyses was that the average capacity factors for pressurized water reactors (PWRs) continued to increase over time. The 1990-1994 average capacity factor for PWRs was 72.8% [7], which represented an increase of approximately 15% over previous simulation results and historical data. Adjustments for this change are discussed further in Section 2.3 with respect to the latest forced outage rates and scheduled outage rates adopted in this analysis. Section 3 also addresses this issue with respect to the final cost estimates. The capacity factors of boiling water reactors (BWRs) did not show the same increase in recent years. The five-year average for these reactors was 62.9%, which was still within the 62%-65% range that was reported in previous results [3].

2.2 POWER POOL DESIGNATIONS

As in the past, replacement energy cost results presented in this report are based on simulations of power pools. Power pools range from groups of tightly linked utilities with centralized dispatching of generating units to groups of nearly independent utilities with cooperative agreements for power interchanges. Power pool simulations yield more realistic estimates of replacement energy costs than do individual utility simulations because economy energy exchanges within each pool are modeled directly. It should be noted that the cost to a utility may be higher than for the power pool as a whole. Transfer payments between utilities above the production cost were not included.

Figure 1 illustrates the approximate geographical boundaries of the nine National Electricity Reliability Council (NERC) regions. Members and associate members of these regions include



ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interpool Network

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

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FIGURE 1 NERC Regions

virtually all of the generating capability in the United States. The compositions of power pools are described in Table 1, and their locations are displayed in Figure 2. The groupings of utilities into power pool areas, which constitute subregions of NERC regions, were assigned according to objectives outlined in Reference 3.

For this study, simulations were performed for pools 7 (PJM), 8 (ComEd), 12 (MAPP), 14 (NEPOOL), 19 (VACAR), and 27 (CA-NV) to obtain maximum reactor coverage (these pools include 59 of the 109 units in service) and to provide a representative sampling of generation mixes and fuel prices. Table 2 displays the number of reactors in each of the 20 power pools that include operating reactors.

2.3 RECENT DATA UPDATES

This section describes the types of data updates that were implemented for this analysis relative to the last study conducted in 1992. A more thorough background discussion on data sources and assumptions is included in Reference 3. The primary categories of areas that were updated include generating unit inventory, forced outage rates, system loads, fuel prices, and O&M costs.

2.3.1 Generating Unit Inventory

A partial review and update of the generating unit inventory was completed for this analysis. This task was important because there is a direct relationship between replacement energy costs and the population of generators available to respond to a reactor outage. The inventory review relied on annual NERC reports as it had in the past [8-16], but it was somewhat abbreviated in that only future additions and retirements were examined and updated in the Argonne Power Plant Inventory (APPI). For previous studies, and for interim database maintenance tasks (up to and including 1994 editions of References 8-16), the complete lists of existing units from NERC publications were also verified against current database entries.

The more thorough review and update are preferred because, in some instances, changes in generating unit status occurred without first being announced by utilities (e.g., units were retired when there were no preannounced plans in the NERC reports to do so). Only by checking the complete lists of existing facilities can such unannounced changes in status be tracked accurately over time. Although some changes may have occurred during 1994 and 1995, the potential discrepancies are expected to have minimal effects on the net replacement energy cost results and adjustment factors developed for this report.

TABLE 1 Compositions of Power Pools

Power Pool	NERC Region	Power Pool Composition
1[a]	ECAR	American Electric Power System, Buckeye Power Inc., Ohio Valley Electric Corp., Richland Power and Light
2[a]	ECAR	Central Area Coordination Group, Byron Municipal Light and Water, Cleveland Division of Light and Power
3	ECAR	Allegheny Power System
4[a]	ECAR	Michigan Electric Coordinated Systems, Michigan Municipal Cooperative Pool, Detroit Public Lighting Dept., Edison Sault Electric Co., Lansing Board of Water and Light, Michigan Public Power Agency
5-6[a,b]	ERCOT	Texas Interconnected Systems, associate members of ERCOT
7[a]	MAAC	Pennsylvania-New Jersey-Maryland Interconnection, associate members of MAAC
8[a]	MAIN	Commonwealth Edison Co.
9-10[a,c]	MAIN	Illinois-Missouri Group (South-Central Illinois Subregion and East Missouri Subregion of MAIN)
11[a]	MAIN	Wisconsin-Upper Michigan Subregion of MAIN
12[a]	MAPP	Mid-Continent Area Power Pool (MAPP)
13	MAPP	Nonmember utilities in the MAPP region
14[a]	NPCC	New England Power Pool
15[a]	NPCC	New York Power Pool
16[a]	SERC	Florida subregion of SERC
17[a]	SERC	Southern subregion of SERC
18[a]	SERC	Tennessee Valley Authority
19[a]	SERC	Virginia-Carolinas Subregion of SERC

TABLE 1 (Cont.)

Power Pool	NERC Region	Power Pool Composition
20[a]	SPP	Group A (W. Arkansas-Louisiana-Mississippi area of SPP)
21	SPP	Group B (Oklahoma area of SPP)
22[a]	SPP	Group C (W. Missouri-Kansas area of SPP)
23, 24	--	No longer used. Originally covered two additional groups in SPP until that region was characterized by three groups.
25[a]	WSCC	Northwest Power area of WSCC
26[a]	WSCC	Arizona-New Mexico area of WSCC
27[a]	WSCC	California-Nevada area of WSCC
28	WSCC	Rocky Mountain area of WSCC
29	--	Alaska Systems Coordinating Council (affiliate NERC member)
30	--	Hawaii
31	ECAR	Cincinnati Gas and Electric Co., Dayton Power and Light Co., Hamilton Dept. of Public Utilities Electric Division
32	ECAR	Kentucky Utilities Group, Big Rivers Electric Corp., Eastern Kentucky Power Cooperative Inc., Henderson Municipal Power and Light, Louisville Gas and Electric Co., Owensboro Municipal Utilities
33	ECAR	Hoosier Energy Rural Electric Cooperative Inc., Indianapolis Power and Light Co., Northern Public Service Co., Public Service Co. of Indiana Inc., Southern Indiana Gas and Electric Co., Wabash Valley Power Assoc.

[a] Power pool containing at least one reactor considered in this study.

[b] Although there are two components of the ERCOT region (basically the Texas Utilities Group and the Central and Southwest Group), they are treated as a single power pool in this study because the Texas Interconnected System provides a high level of coordination in planning and operation.

[c] The two components of the Illinois-Missouri Group are treated as a single pool because of their high level of coordination in planning and operation.

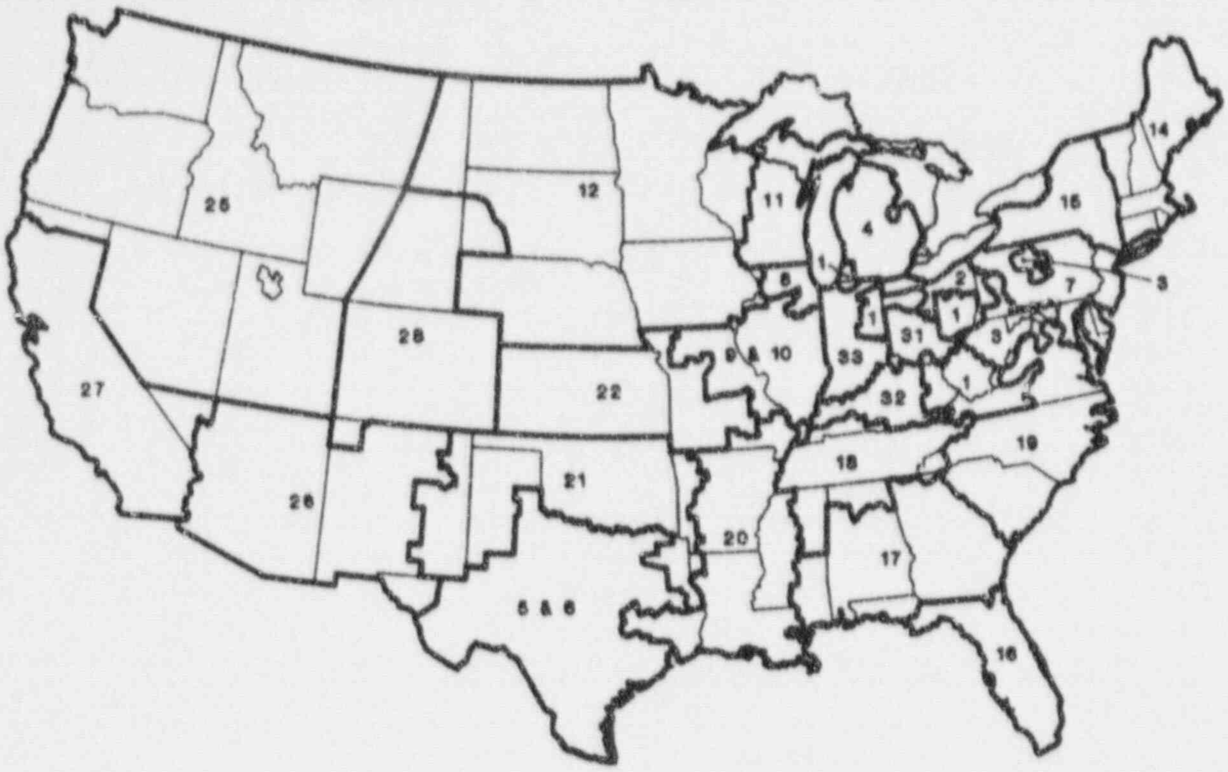

FIGURE 2 Approximate Geographical Boundaries of Power Pools (see Table 1 for definitions)

TABLE 2 Number of Reactors in Each Power Pool[a]

Power Pool	No. of Reactors	Power Pool	No. of Reactors
1	2	15	6
2	4	16	5
4	3	17	6
5-6	4	18	5
7	13	19	16
8	12	20	5
9-10	2	22	1
11	3	25	1
12	6	26	3
14	8	27	4
			109

[a] Dispatching simulations were conducted for the shaded power pools.

2.3.2 Outage Rates

TABLE 3 Outage Rates and Net Capacity Factors (%)

Reactor Type	EFOR	SOF	NCF
PWR	9.2	16.2	72.8
BWR	19.6	17.2	62.9

Both planned (scheduled) and unplanned (forced) outage rates were reviewed and updated for all types of generating facilities on the basis of data published by NERC [7]. These failure rates are important to represent, for both nuclear units and nonnuclear generating facilities, because they affect the potential capacity factors for all types of generating capacity in each power pool. Thus, the amount of energy to be replaced during potential nuclear shutdowns and the mix of generation that can be used to replace that energy are affected by these outage rates. It also follows that the replacement costs (expressed in dollars per day [$/d] and mills per kilowatt-hour [mills/kWh]) are both impacted by the forced outage rates.

Outage rates are differentiated in the NERC reports and in the ICARUS simulations by unit type (steam, combustion turbine, etc.), fuel type (oil, coal, nuclear, etc.), and unit size. For nuclear units, the outage factors are also differentiated according to BWRs and PWRs. As noted in Section 2.1, the average capacity factors for PWRs have increased over time. While equivalent forced outage rates (EFORs) for PWRs remained relatively stable during the recent past, scheduled outage factors (SOFs) decreased significantly, from 22.2% in 1990 to 11.8% in 1994 [7].

On the basis of five-year 1990-1994 averages [7], the EFORs and SOFs shown in Table 3 were adopted for this analysis. The net capacity factors (NCFs) are the historical generation averages that correspond to the same five-year period. By using the EFORs and SOFs shown in this table, the ICARUS dispatching results provided close matches (within 1-2%) with the five-year average NCFs. For uniformity, the capacity factors and associated generation estimates shown in Section 3 assume rounded NCF values of 73% for all PWRs and 63% for all BWRs.

2.3.3 System Loads

System load data were updated with new annual peak estimates and annual peak growth rates reported by each of the NERC regions [8-16]. Peak loads, expressed in megawatts, are reported for each power pool in the United States in the NERC reports. Overall system loads affect replacement energy costs because they determine how the replacement generation capabilities are distributed over the mix of fuel types and generating technologies in a system. In general, higher peak loads increase replacement energy costs by increasing the normal demands for all sources of energy.

However, routine maintenance schedules can reverse the correlation between replacement energy costs and peak loads. It is not unusual for significant numbers of low-cost generating units to be scheduled for maintenance during off-peak load periods, with little or no routine maintenance scheduled during peak periods. This minimizes the risk of serious system reliability problems during times with highest loads. Previous results [3] revealed this type of nonintuitive outcome; in many power pools, the lowest replacement costs occurred in the seasons with the highest loads (usually summer for most U.S. systems).

2.3.4 Fuel Prices

Fossil fuel prices were updated with 1994 data from DOE's Energy Information Administration (EIA) [17]. The information is available electronically and is reported on a plant basis for units in the United States. Power pool averages were developed from the data for each major fuel category (residual and distillate oil, natural gas, bituminous and subbituminous coal, etc.). These averages were then adjusted by using recent gross national product (GNP) price deflators [18] to estimate the prices in mid-1996 dollars.

Nuclear fuel prices were estimated on the basis of another EIA data source [19]. Table 4 displays historical costs for 1990-1994 that reveal steady decreases in real terms but also show a leveling off between 1993 and 1994. For this study, the 1994 average cost was adopted as a reference fuel price. After adjustments for inflation and for an assumed ratio of variable fuel costs to fixed fuel costs of 90% to 10%, the variable nuclear fuel cost was assumed to be \$6 (mid-1996 dollars) per megawatt-hour (MWh). In contrast to previous investigations that used plant-specific estimates of nuclear fuel prices, in this study, the average value was applied uniformly to each reactor.

2.3.5 Operation and Maintenance Costs

O&M costs for fossil-fueled generating units were updated strictly according to inflation, measured in terms of actual GNP price deflators for 1991-1995 and an estimated deflator for 1996. A net increase of 9.2% was estimated for the overall 1991-1996 adjustment.

For nuclear O&M costs, the five-year 1990-1994 averages (shown in Table 5 [19]) were examined for recent trends. Historically, O&M costs have been difficult to predict because of periods of multiyear increases followed by periods of stability or even reductions. The latest five-year estimates show increases from 1990 to 1992, followed by reductions in 1993 and 1994. The 1994 reduction can be attributed, in part, to improved capacity factors and the associated increase in generation (in kWh) that is used to calculate the average O&M costs.

TABLE 4 Historical Nuclear Fuel Costs

Year	Average Fuel Cost ($/MWh)
1990	7 18
1991	6.71
1992	6.12
1993	5.88
1994	5.87

TABLE 5 Historical Nuclear O&M Costs

Year	Average O&M Cost ($/MWh)
1990	15.72
1991	15.99
1992	16.36
1993	15.93
1994	14.99

However, without sufficient evidence to justify continued decreases in these costs, and because of recent fluctuations, this study assumed that the 1993 average would be representative for the near future. This assumption was somewhat more conservative than it would be if the 1994 value were used. After adjustments to express the costs in 1996 dollars, the final evaluations found that 16.3 mills/kWh were used for total O&M. The variable portion of this cost was assumed to be 10% of the total on the basis of previous investigations [3]. The net result was a variable O&M component of 1.6 mills/kWh.

3 RESULTS

All cost estimates described in this section are referenced to mid-1996 undiscounted dollars. The outcomes are characterized by ranges of costs that are intended to capture three sources of variation:

a. Seasonal variations within a given simulation year (1997-2001),

b. Annual variations for 1997-2001, and

c. Approximation uncertainties for power pools not directly modeled.

Table 6 includes a confidence designator for each of the 109 reactors expected to operate during the 1997-2001 study period to indicate whether the unit is

1. One of 59 reactors located in one of the six simulated power pools, or

2. One of 50 reactors that were estimated from the other power pool results.

For units in category 1, the ranges in costs primarily reflect seasonal and annual variations, as noted in categories a and b above. For reactors in category 2, the cost ranges are intended to include approximation uncertainties (c) in addition to seasonal and annual sensitivities (a and b).

For reference, more detailed seasonal results for each of the six simulated power pools are included in the appendix, Tables A.1-A.6 and A.8-A.13. These results are formatted in the traditional tabular form published in References 1-3. Table A.7 is a new summary table that provides estimates of the annual average costs for each power pool simulated. Section 3.3 discusses the use of Table A.7 to potentially narrow the range of cost estimates under certain conditions.

3.1 REPLACEMENT COST ESTIMATES

Table 6 summarizes the findings for each of 109 reactors. The results are grouped first by NERC region and power pool, then listed alphabetically by reactor name and number. (NERC regions are shown in Figure 1, and power pools are defined in Table 1.)

TABLE 6 Replacement Energy Cost Results

NERC Region and Reactor Name	Power Pool	Reactor Type	Unit Size (MW)	Annual Capacity Factor (%)	Annual Generation (10^6 kWh)	Cost (mills/kWh)	Cost ($\$10^3$/d)	Confidence Indicator[a]
ECAR								
Cook 1	1	PWR	1,000	73	6,395	10-35	175-613	2
Cook 2	1	PWR	1,060	73	6,778	10-35	186-650	2
Beaver Valley 1	2	PWR	810	73	5,180	10-35	142-497	2
Beaver Valley 2	2	PWR	820	73	5,244	10-35	144-503	2
Davis-Besse	2	PWR	877	73	5,608	10-35	154-538	2
Perry 1	2	BWR	1,166	63	6,435	10-35	176-617	2
Big Rock Point	4	BWR	67	63	370	10-35	10-35	2
Fermi 2	4	BWR	1,085	63	5,988	10-35	164-574	2
Palisades	4	PWR	730	73	4,668	10-35	128-448	2
ERCOT								
Comanche Peak 1	5-6	PWR	1,150	73	7,354	10-35	201-705	2
Comanche Peak 2	5-6	PWR	1,150	73	7,354	10-35	201-175	2
South Texas 1	5-6	PWR	1,251	73	8,000	10-35	219-767	2
South Texas 2	5-6	PWR	1,251	73	8,000	10-35	219-767	2
MAAC								
Calvert Cliffs 1	7	PWR	830	73	5,308	14-19	204-276	1
Calvert Cliffs 2	7	PWR	830	73	5,308	14-19	204-276	1
Hope Creek 1	7	BWR	1031	63	5,690	14-19	218-296	1
Limerick 1	7	BWR	1055	63	5,822	14-19	223-303	1
Limerick 2	7	BWR	1055	63	5,822	14-19	223-303	1

TABLE 6 (Cont.)

NERC Region and Reactor Name	Power Pool	Reactor Type	Unit Size (MW)	Annual Capacity Factor (%)	Annual Generation (10^6 kWh)	Cost (mills/kWh)	Cost ($\$10^3$/d)	Confidence Indicator[a]
MACC (Cont.)								
Oyster Creek	7	BWR	610	63	3,366	14-19	129-175	1
Peach Bottom 2	7	BWR	1,055	63	5,822	14-19	223-303	1
Peach Bottom 3	7	BWR	1,035	63	5,712	14-19	219-297	1
Salem 1	7	PWR	1,106	73	7,073	14-19	271-368	1
Salem 2	7	PWR	1,106	73	7,073	14-19	271-368	1
Susquehanna 1	7	BWR	1,040	63	5,740	14-19	220-299	1
Susquehanna 2	7	BWR	1,044	63	5,762	14-19	221-300	1
Three Mile Island 1	7	PWR	786	73	5,026	14-19	193-262	1
MAIN								
Braidwood 1	8	PWR	1,120	73	7,162	17-25	334-491	1
Braidwood 2	8	PWR	1,120	73	7,162	17-25	334-491	1
Byron 1	8	PWR	1,105	73	7,066	17-25	329-484	1
Byron 2	8	PWR	1,105	73	7,066	17-25	329-484	1
Dresden 2	8	BWR	772	63	4,261	17-25	198-292	1
Dresden 3	8	BWR	773	63	4,266	17-25	199-292	1
LaSalle 1	8	BWR	1,036	63	5,717	17-25	266-392	1
LaSalle 2	8	BWR	1,036	63	5,717	17-25	266-392	1
Quad Cities 1	8,12	BWR	769	63	4,244	16-26	186-302	1
Quad Cities 2	8,12	BWR	769	63	4,244	16-26	186-302	1
Zion 1	8	PWR	1,040	73	6,651	17-25	310-456	1
Zion 2	8	PWR	1,040	73	6,651	17-25	310-456	1
Callaway	9-10	PWR	1,120	73	7,162	10-35	196-687	2

TABLE 6 (Cont.)

NERC Region and Reactor Name	Power Pool	Reactor Type	Unit Size (MW)	Annual Capacity Factor (%)	Annual Generation (10^6 kWh)	Cost (mills/kWh)	Cost ($\$10^3$/d)	Confidence Indicator[a]
MAIN (Cont.)								
Clinton	9-10	BWR	930	63	5,132	10-35	141-492	2
Kewaunee	11	PWR	511	73	3,268	10-35	90-313	2
Point Beach 1	11	PWR	485	73	3,101	10-35	85-297	2
Point Beach 2	11	PWR	485	73	3,101	10-35	85-297	2
MAPP								
Duane Arnold	12	BWR	515	63	2,842	12-30	93-234	1
Cooper	12	BWR	764	63	4,216	12-30	139-347	1
Fort Calhoun	12	PWR	478	73	3,057	12-30	100-251	1
Monticello	12	BWR	536	63	2,958	12-30	97-243	1
Praire Island 1	12	PWR	513	73	3,281	12-30	108-270	1
Praire Island 2	12	PWR	512	73	3,274	12-30	108-269	1
NPCC								
Haddam Neck	14	PWR	560	73	[illegible]	[illegible]	167-186	1
Maine Yankee	14	PWR	860	73	[illegible]	[illegible]	256-286	1
Millstone 1	14	PWR	641	73	[illegible]	[illegible]	[illegible]-213	1
Millstone 2	14	PWR	873	73	[illegible]	[illegible]	[illegible]	1
Millstone 3	14	PWR	1,137	73	[illegible]	[illegible]	[illegible]	1
Pilgrim 1	14	BWR	670	63	[illegible]	[illegible]	[illegible]	1
Seabrook 1	14	PWR	1,150	73	[illegible]	[illegible]	[illegible]	1
Vermont Yankee	14	BWR	504	63	2,78[illegible]	[illegible]	[illegible]	
Fitzpatrick	15	BWR	780	63	4,305	10-35	[illegible]	[illegible]

TABLE 6 (Cont.)

NERC Region and Reactor Name	Power Pool	Reactor Type	Unit Size (MW)	Annual Capacity Factor (%)	Annual Generation (10^6 kWh)	Cost (mills/kWh)	Cost ($\$10^3$/d)	Confidence Indicator[a]
NPCC (Cont.)								
Ginna	15	PWR	470	73	3,006	10-35	82-288	2
Indian Point 2	15	PWR	951	73	6,081	10-35	167-583	2
Indian Point 3	15	PWR	965	73	6,171	10-35	169-592	2
Nine Mile Point 1	15	BWR	565	63	3,118	10-35	85-299	2
Nine Mile Point 2	15	BWR	994	63	5,486	10-35	150-526	2
SERC								
Crystal River 3	16	PWR	821	73	5,250	10-35	144-503	2
St. Lucie 1	16	PWR	839	73	5,365	10-35	147-514	2
St. Lucie 2	16	PWR	839	73	5,365	10-35	147-514	2
Turkey Point 3	16	PWR	666	73	4,259	10-35	117-408	2
Turkey Point 4	16	PWR	666	73	4,259	10-35	117-408	2
Farley 1	17	PWR	812	73	5,193	10-35	142-498	2
Farley 2	17	PWR	822	73	5,257	10-35	144-504	2
Hatch 1	17	BWR	737	63	4,067	10-35	111-390	2
Hatch 2	17	BWR	757	63	4,178	10-35	114-401	2
Vogtle 1	17	PWR	1,158	73	7,405	10-35	203-710	2
Vogtle 2	17	PWR	1,157	73	7,399	10-35	203-709	2
Browns Ferry 2	18	BWR	1,065	63	5,878	10-35	161-564	2
Browns Ferry 3	18	BWR	1,065	63	5,878	10-35	161-564	2
Sequoyah 1	18	PWR	1,122	73	7,175	10-35	197-688	2
Sequoyah 2	18	PWR	1,122	73	7,175	10-35	197-688	2
Watts Bar 1	18	PWR	1,165	73	7,450	10-35	204-714	2

TABLE 6 (Cont.)

NERC Region and Reactor Name	Power Pool	Reactor Type	Unit Size (MW)	Annual Capacity Factor (%)	Annual Generation (10^6 kWh)	Cost (mills/kWh)	Cost ($\$10^3$/d)	Confidence Indicator[a]
SERC (Cont.)								
Brunswick 1	19	BWR	767	63	4,233	12-20	139-232	1
Brunswick 2	19	BWR	754	63	4,161	12-20	137-228	1
Catawba 1	19	PWR	1,129	73	7,220	12-20	237-396	1
Catawba 2	19	PWR	1,129	73	7,220	12-20	237-396	1
Harris 1	19	PWR	860	73	5,500	12-20	181-301	1
McGuire 1	19	PWR	1,129	73	7,220	12-20	237-396	1
McGuire 2	19	PWR	1,129	73	7,220	12-20	237-396	1
North Anna 1	19	PWR	900	73	5,755	12-20	189-315	1
North Anna 2	19	PWR	887	73	5,672	12-20	186-311	1
Oconee 1	19	PWR	846	73	5,410	12-20	178-296	1
Oconee 2	19	PWR	846	73	5,410	12-20	178-296	1
Oconee 3	19	PWR	846	73	5,410	12-20	178-296	1
Robinson 2	19	PWR	683	73	4,368	12-20	144-239	1
Summer	19	PWR	885	73	5,659	12-20	186-310	1
Surry 1	19	PWR	781	73	4,994	12-20	164-274	1
Surry 2	19	PWR	781	73	4,994	12-20	164-274	1
SPP								
Arkansas Nuclear 1	20	PWR	836	73	5,346	10-35	146-513	2
Arkansas Nuclear 2	20	PWR	858	73	5,487	10-35	150-526	2
Grand Gulf 1	20,17	BWR	1,143	63	6,308	10-35	173-605	2
River Bend 1	20	BWR	936	63	5,166	10-35	142-495	2
Waterford 3	20	PWR	1,075	73	6,874	10-35	188-659	2
Wolf Creek 1	22	PWR	1,134	73	7,252	10-35	199-695	2

TABLE 6 (Cont.)

NERC Region and Reactor Name	Power Pool	Reactor Type	Unit Size (MW)	Annual Capacity Factor (%)	Annual Generation (10^6 kWh)	Cost (mills/kWh)	Cost ($\$10^3$/d)	Confidence Indicator[a]
WSCC								
Washington Nuclear 2	25	BWR	1,086	63	5,993	10-35	164-575	2
Palo Verde 1	26,27	PWR	1,221	73	7,808	12-31	257-663	2
Palo Verde 2	26,27	PWR	1,221	73	7,808	12-31	257-663	2
Palo Verde 3	26,27	PWR	1,221	73	7,808	12-31	257-663	2
Diablo Canyon 1	27	PWR	1,073	73	6,862	16-19	301-357	1
Diablo Canyon 2	27	PWR	1,087	73	6,951	16-19	305-362	1
San Onofre 2	27	PWR	1,070	73	6,842	16-19	300-356	1
San Onofre 3	27	PWR	1,080	73	6,906	16-19	303-360	1

[a] The confidence indicator was assigned a value of "1" or "2" as follows:

"1" indicates the reactor was located in one of the six power pools that were fully simulated with a base case and a shutdown case. Comparisons of the two simulations for each pool provide reliable estimates of shutdown costs as expressed in mills/kWh. The ranges for these reactors reflect annual and seasonal variations. The costs (as expressed in thousands of dollars per day) were scaled for each reactor according to unit size and expected capacity factor.

"2" indicates that the reactor was not in a simulated power pool. The costs (as expressed in mills per kilowatt-hour) for these units were all assigned a range of 10-35 mills/kWh on the basis of values encountered for the six simulated pools, with some widening of the range to account for uncertainties in pool-dependent replacement supply characteristics (in addition to annual and seasonal variations). The costs (as expressed in thousands of dollars per day) were then scaled according to reactor size and expected capacity factors.

Table 6 also includes indicators for:

- Reactor type: boiling water reactor (BWR) or pressurized water reactor (PWR),

- Unit size (MW): net nameplate rating in megawatts;

- Annual capacity factor (%): ratio of net annual generation divided by the product of unit size and number of hours in a year, expressed as a percentage;

- Annual generation (10^6 kWh): net expected annual generation expressed in millions of kilowatt-hours;

- Cost (mills/kWh): net replacement energy cost expressed in tenths of a cent per kilowatt-hour;

- Cost ($\$10^3$/d): net replacement energy cost expressed in thousands of dollars per day, assuming a net capacity factor as shown in the table;

- Confidence indicator: assigned a value of "1" for reactors in a pool that was simulated and "2" for reactors in a pool that was not simulated (see footnote to Table 6).

3.2 EXAMPLES ON HOW TO APPLY RESULTS

This section provides several examples on how to apply the replacement energy cost estimates. The underlying logic for these calculations is very similar to the guidance provided in Reference 3. However, without the seasonal and multiyear data developed in previous analyses, the examples shown here focus on cost ranges rather than point estimates. Special considerations and/or adjustments need to be addressed when the estimates involve issues such as coincidence with planned or unplanned outages or other factors that affect the expected generation to be replaced.

Example 1:

Estimate the range of replacement energy costs for a one-year shutdown of Calvert Cliffs 1 occurring in the 1997-2001 time period, assuming that there are no alterations to the expected capacity factor of 73%.

Use the data for Calvert Cliffs 1 (NERC region MAAC, power pool 7) from Table 6.

Cost = (\$204,000-\$276,000/d) $\times$ 365 d
= \$74.5-\$100.7 million (mid-1996 dollars)

The result indicates costs are expected to fall in the range between \$74.5 million and \$100.7 million.

Example 2:

Estimate the range of costs for a two-day shutdown of Calvert Cliffs 1, assuming that the annual average capacity factor occurs for those two days.

Use the data from Table 6 (similar to Example 1).

Cost = (\$204,000-\$276,000/d) $\times$ 2 d
= \$408,000-\$552,000

Example 3:

Repeat Example 2, but assume the capacity factor for Calvert Cliffs 1 would have been 100% for the two days of outage.

Repeat the calculation for the two-day outage and scale the results according to the ratio of the desired capacity factor to the reported average annual capacity factor.

Cost = (\$204,000-\$276,000) $\times$ 2 d $\times$ (100/73)
= \$559,000-\$756,000

Example 4:

Compute the range of costs for a one-year shutdown for Calvert Cliffs 1, assuming that no forced outages occur during that year but that planned maintenance and refueling occur as usual.

First determine the new expected annual capacity factor. Assuming that the planned outage rate is 16.2% (approximately 59 days) as estimated in Table 3 (SOF for BWRs), the annual capacity factor would be approximately 83.8%, with no other outages or deratings. Use this new capacity factor to scale the annual cost estimate.

$$\text{Cost} = (\$204{,}000\text{-}\$276{,}000) \times 365\ \text{d} \times (83.8/73.0)$$
$$= \$85.5\text{-}\$115.6\ \text{million}$$

Example 5:

Estimate the range of costs for a two-day shutdown of Perry 1, assuming that the reactor would have generated at full capacity for that time period.

Repeat the procedure outlined in Example 3, but use the results from Perry 1 and scale the outcome by 63% (for BWRs) instead of 73% (for PWRs).

$$\text{Cost} = (\$176{,}000\text{-}\$617{,}000) \times 2\ \text{d} \times (100/63)$$
$$= \$559{,}000\text{-}\$1{,}959{,}000$$

3.3 ADDITIONAL GUIDANCE ON RANGES OF ESTIMATES

The supplemental data provided in the appendix may be used to refine the cost estimates for reactors located in one of the six simulated power pools. The analyst can review the seasonal and annual trends to determine whether costs for a particular shutdown would be more likely to be at the low or high end of the ranges shown in Table 6 or whether mid-range values would be more appropriate.

For example, to estimate a two-day shutdown for Calvert Cliffs 1 scheduled in advance for the spring of 2001, Table A.1 indicates that compared with other seasons and other years, a high-end estimate would be more likely. For longer-term shutdowns, the seasonal distribution of results shown in the appendix may also be reviewed to more closely estimate the overall outcomes. For the Calvert Cliffs 1 case in Example 1, the costs shown for a given year in Table A.1 are not heavily skewed over the seasons, so a reasonable cost estimate for a one-year shutdown might be $90-$95 million. This is a somewhat narrower range than the $75-$101 million estimated from Table 6.

Table A.7 was added to the appendix as a supplement to the data provided in Tables 6 and A.1-A.6. Because many of the seasonal costs span wide ranges, the annual estimates may provide useful averages for analyzing outages that might approach a year in duration or that may not be well-defined in terms of seasonal timing. The costs given in Table A.7 represent annual average costs for each of the six simulated power pools. Here is a sixth example for estimating costs:

Fxample 6:

Estimate the cost of a one-year shutdown for Calvert Cliffs 1 occurring in the year 2000, assuming that generation matches the expected 73% capacity factor.

Use data from Table A.7 to estimate that the annual average replacement energy cost is 7.0 mills/kWh.

$$\text{Cost} = 865\text{MW} \times 8760 \text{ h/yr} \times 73\% \times 17.0 \text{ mills/kWh}$$
$$= \$94.0 \text{ million (mid-1996 dollars)}$$

For reactors not located in one of the six simulated power pools, the appendix does not provide very much assistance. Previous experience has demonstrated that each power pool is unique. In this most recent update, a comparison of current and previous outcomes confirmed the unpredictability of seasonal and annual patterns. The results for power pool 12 (MAPP) are a good example. Results in previous reports such as Reference 3 showed relatively small seasonal and annual variations (e.g., costs spanned a range of approximately ±30% for a given reactor from 1991-1996). In contrast, the latest estimates cover a range of 12-30 mills/kWh for 1997-2001.

Although the range adopted for pools not simulated is very large (10-35 mills/kWh), the study findings suggest that simple cost multipliers should not be applied to the outcomes shown in previous reports. For some power pools, this means that the actual costs are probably much nearer the upper or lower ends of the estimated ranges, but identifying which pools fall into this category was beyond the scope of this project.

However, as a final note of guidance for evaluating shutdowns in pools that were not simulated, the analyst may choose to use the results published in Reference 3 to make judgments about whether costs might be most likely to be at the low or high end of the ranges specified in Table 6. For example, Pool 15 has historically exhibited relatively high costs (approximately 30-35 mills/kWh). This finding could be considered an indicator that future costs might also be expected to be relatively high (within the 10-35 mills/kWh range shown in Table 6). The final choice is left to the discretion of the analyst, because as noted earlier, in several instances, seasonal cost outcomes for the new simulations significantly departed from previous cost patterns.

3.4 MULTIPLE REACTOR SHUTDOWNS

The previous studies included analyses of multiple unit shutdowns. Results from these investigations confirmed that shutting down more than one reactor at a given time increases the replacement energy costs relative to the single unit shutdown costs. For some pools containing a large number of reactors, Reference 3 showed that the increase could be as much as 30% for multiple shutdowns. The equivalent evaluations were not conducted for this update study, so all of the costs in Table 6 and the appendix reflect costs for single unit shutdowns. It is likely that sensitivities to multiple shutdowns have increased in many of the power pools because of decreases in reserve margins that have occurred since Reference 3 was completed.

3.5 OIL AND GAS PRICE SENSITIVITIES

Tables A.8-A.13 show the latest sensitivities to changes in oil and gas prices for the six power pools analyzed in this study. The adjustment factors in these tables can be used as simple multipliers that can be applied to the costs in Table 6 (mills/kWh or $/d). For reference, the average price for crude oil was estimated to be approximately $16/per barrel (bbl) on the basis of 1994 fuel prices and escalated to 1996 dollars.

On the basis of these indicators, to estimate the shutdown cost range for Calvert Cliffs 1 with a crude oil price of $24/bbl (50% increase), the analyst should multiply the costs in Table 6 by a factor of 1.16-1.32, depending on the year and season of interest (refer to Table A.7 for pool 7). For annual shutdowns, an average multiplication factor of approximately 1.22 (22% increase) would provide a reasonable estimate of the sensitivity to oil and gas price increases of 50%.

Reference 3 provides a further discussion of the assumptions and methodology used in developing these sensitivity factors. These comments should be reviewed for a better understanding of the usefulness and limitations of these multipliers. Because of the uniqueness of each power pool, there are no simple procedures for extrapolating the fuel price sensitivity results in the appendix to the other power pools. For the six pools that were simulated, the sensitivity factors for some were very similar to previous results from Reference 3, while others showed significant departures.

4 SUMMARY

This report estimates replacement energy costs for 109 reactors expected to be in operation between 1997 and 2001. This update to References 1-3 represents an abbreviated investigation when compared with these earlier analyses. Instead of simulating each of the 109 reactors to estimate seasonal costs, this study developed cost ranges for six of the 20 power pools with operating reactors. Results of simulations using these ranges for the six power pools provide very good cost estimates for the 59 reactors located in these pools. The simulation results also provide good upper and lower bounds for cost ranges for the other 50 reactors located in pools that were not simulated.

For the 59 reactors located in pools that were simulated, the variation in cost ranges from a low of about 17-19 mills/kWh (10% variation) to a high of about 12-30 mills/kWh (250% variation). These variations reflect real seasonal and annual variations in the costs for alternative sources of replacement energy. System loads, new unit construction schedules, retirement schedules, and other system dynamics all influence the seasonal cost figures. For the other 50 reactors located in pools that were not simulated, the cost range is even greater, from 10-35 mills/kWh. For these units, the range reflects not only seasonal and annual variations but also other basic estimation uncertainties.

This exercise provided further confirmation that there is no substitute for using detailed production cost simulations when estimating replacement energy costs. The original intent of this analysis was to develop simple cost multipliers that could be applied to the previously simulated reactor-specific seasonal shutdown costs. However, recent changes in many factors such as generation mix, reserve margins, and fuel prices caused unpredictable trends to emerge in the latest update of replacement energy costs. This result not only led to a departure from presenting simple multipliers but also accounts for the large range in cost estimates for many reactors.

5 REFERENCES

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APPENDIX:

REPLACEMENT ENERGY COST DATA

This appendix contains the output tables produced for each of six reactors that were simulated for this study. The format for these tables is identical to the published results presented in earlier reports [1-3]. Tables A.1-A.6 contain the reactor-specific seasonal replacement energy cost results. Table A.7 summarizes average annual replacement energy costs for each power pool (discussed in Section 3.3) Tables A.8-A.13 contain the oil and gas price sensitivity results (see Section 3.5).

Tables A.1-A.6 show plant-specific variable fuel costs that were used initially in the simulations (e.g., 41¢/10^6 Btu for Calvert Cliffs 1, or 4.9 mills/kWh). These fuel costs were overridden during the final analysis because they were based on 1991 data, and evidence was not sufficient to support the extrapolation of these values to plant-specific costs for 1996. The final results reported in Table 6 assume a variable fuel cost for all reactors of 6 mills/kWh, which resulted in an adjustment of ±1-2 mills/kWh relative to the results shown in Tables A.1-A.6.

With regard to Tables A.8-A.13, the reference price for crude oil was approximately $16/bbl. Section 3.5 describes the application of these results to reactors in one of the six power pools that were simulated. The analyst is cautioned against extrapolating these results to reactors in the other power pools, because the fuel price sensitivities and trends are difficult to predict without a full set of production-cost simulations.

TABLE A.1 Replacement Energy Data for Calvert Cliffs 1

Power Pool:	7	Unit Size (MW):	865
NERC Region:	MAAC	Heat Rate (Btu/kWh):	11900
Utility:	Baltimore Gas and Electric Co.	Variable Fuel Cost (¢/10^6 Btu)):	41

	Seasonal Operating Statistics			Seasonal Production-Cost Increase Due to Short-Term Shutdown		
Season and Year	Generation to Be Replaced (10^6 kWh)	Capacity Factor (%)	% of Season in Service	Total ($\$10^6$)	Average per kWh Replaced (mills/kWh)	Average per Day ($\$10^3$/d)
Winter - 1996/97	1390	73.4	100.0	22.4	16.1	246
Spring - 1997	1396	73.7	100.0	23.7	17.0	260
Summer - 1997	1368	72.2	100.0	20.7	15.1	227
Fall - 1997	1392	73.5	100.0	23.5	16.9	258
Winter - 1997/98	1393	73.5	100.0	22.8	16.4	250
Spring - 1998	1398	73.8	100.0	23.7	16.9	259
Summer - 1998	1368	72.2	100.0	20.8	15.2	227
Fall - 1998	1389	73.3	100.0	23.7	17.1	260
Winter - 1998/99	1393	73.5	100.0	23.7	17.0	260
Spring - 1999	1395	73.7	100.0	24.6	17.6	269
Summer - 1999	1371	72.4	100.0	21.9	16.0	240
Fall - 1999	1394	73.6	100.0	24.1	17.3	264
Winter - 1999/00	1397	73.8	100.0	25.5	18.3	280
Spring - 2000	1399	73.8	100.0	26.2	18.8	288
Summer - 2000	1372	72.4	100.0	22.5	16.4	247
Fall - 2000	1399	73.8	100.0	26.7	19.1	293
Winter - 2000/01	1398	73.8	100.0	26.0	18.6	285
Spring - 2001	1400	73.9	100.0	28.1	20.0	308
Summer - 2001	1373	72.5	100.0	23.5	17.1	258
Fall - 2001	1399	73.9	100.0	27.1	19.3	297

TABLE A.2 Replacement Energy Data for La Salle County 1

Power Pool:	8	Unit Size (MW):	1036
NERC Region:	MAIN	Heat Rate (Btu/kWh)	10500
Utility:	Commonwealth Edison Co.	Variable Fuel Cost (¢/10^6 Btu)):	43

Season and Year	Seasonal Operating Statistics			Seasonal Production-Cost Increase Due to Short-Term Shutdown		
	Generation to Be Replaced (10^6 kWh)	Capacity Factor (%)	% of Season in Service	Total ($\$10^6$)	Average per kWh Replaced (mills/kWh)	Average per Day ($\$10^3$/d)
Winter - 1996/97	1441	63.5	100.0	32.4	22.5	355
Spring - 1997	1433	63.2	100.0	31.3	21.8	343
Summer - 1997	1412	62.3	100.0	25.4	18.0	278
Fall - 1997	1426	62.9	100.0	30.3	21.2	332
Winter - 1997/98	1445	63.7	100.0	32.9	22.8	361
Spring - 1998	1436	63.3	100.0	32.3	22.5	354
Summer - 1998	1414	62.3	100.0	26.0	18.4	285
Fall - 1998	1430	63.0	100.0	31.7	22.1	347
Winter - 1998/99	1451	64.0	100.0	36.0	24.8	395
Spring - 1999	1441	63.5	100.0	34.4	23.9	377
Summer - 1999	1416	62.4	100.0	26.2	18.5	287
Fall - 1999	1432	63.1	100.0	32.1	22.4	351
Winter - 1999/00	1452	64.0	100.0	36.1	24.9	396
Spring - 2000	1443	63.6	100.0	34.8	24.2	382
Summer - 2000	1418	62.5	100.0	26.5	18.7	291
Fall - 2000	1433	63.2	100.0	32.5	22.7	356
Winter - 2000/01	1458	64.3	100.0	39.3	26.9	430
Spring - 2001	1446	63.7	100.0	36.5	25.2	400
Summer - 2001	1419	62.6	100.0	26.9	18.9	294
Fall - 2001	1439	63.4	100.0	34.9	24.2	382

TABLE A.3 Replacement Energy Data for Prairie Island 2

Power Pool: 12		Unit Size (MW):	512
NERC Region: MAPP		Heat Rate (Btu/kWh):	11000
Utility: Northern States Power Co.		Variable Fuel Cost (¢/10^6 Btu):	37

Season and Year	Seasonal Operating Statistics: Generation to Be Replaced (10^6 kWh)	Capacity Factor (%)	% of Season in Service	Seasonal Production-Cost Increase Due to Short-Term Shutdown: Total ($\$10^6$)	Average per kWh Replaced (mills/kWh)	Average per Day ($\$10^3$/d)
Winter - 1996/97	823	73.4	100.0	19.9	24.1	216
Spring - 1997	824	73.5	100.0	19.7	23.9	216
Summer - 1997	813	72.5	100.0	10.5	12.9	115
Fall - 1997	821	73.2	100.0	15.6	19.0	171
Winter - 1997/98	824	73.5	100.0	21.1	25.6	232
Spring - 1998	825	73.5	100.0	20.3	24.6	222
Summer - 1998	814	72.6	100.0	10.9	13.4	120
Fall - 1998	822	73.3	100.0	17.7	21.5	194
Winter - 1998/99	825	73.6	100.0	22.8	27.6	250
Spring - 1999	826	73.7	100.0	22.9	27.7	251
Summer - 1999	815	72.7	100.0	11.7	14.3	128
Fall - 1999	823	73.4	100.0	19.3	23.5	212
Winter - 1999/00	826	73.7	100.0	24.2	29.3	265
Spring - 2000	827	73.7	100.0	24.4	29.5	267
Summer - 2000	816	72.8	100.0	12.4	15.2	136
Fall - 2000	824	73.4	100.0	20.9	25.4	229
Winter - 2000/01	827	73.8	100.0	25.3	30.6	277
Spring - 2001	829	73.9	100.0	26.0	31.3	285
Summer - 2001	818	73.0	100.0	13.6	16.7	149
Fall - 2001	826	73.7	100.0	23.5	28.4	257

TABLE A.4 Replacement Energy Data for Millstone 2

Power Pool:	14	Unit Size (MW):	873
NERC Region:	NPCC	Heat Rate (Btu/kWh):	10500
Utility:	Northeast Utilities	Variable Fuel Cost (¢/10^6 Btu):	69

	Seasonal Operating Statistics			Seasonal Production-Cost Increase Due to Short-Term Shutdown		
Season and Year	Generation to Be Replaced (10^6 kWh)	Capacity Factor (%)	% of Season in Service	Total ($\$10^6$)	Average per kWh Replaced (mills/kWh)	Average per Day ($\$10^3$/d)
Winter - 1996/97	1425	74.5	100.0	21.8	15.3	239
Spring - 1997	1440	75.3	100.0	25.0	17.3	274
Summer - 1997	1401	73.3	100.0	21.6	15.4	236
Fall - 1997	1420	74.3	100.0	22.6	15.9	248
Winter - 1997/98	1426	74.6	100.0	22.3	15.6	244
Spring - 1998	1438	75.2	100.0	24.4	16.9	267
Summer - 1998	1400	73.2	100.0	21.4	15.3	235
Fall - 1998	1426	74.6	100.0	23.6	16.5	259
Winter - 1998/99	1427	74.6	100.0	22.3	15.6	245
Spring - 1999	1441	75.4	100.0	25.4	17.6	278
Summer - 1999	1403	73.4	100.0	21.4	15.3	235
Fall - 1999	1422	74.4	100.0	22.8	16.1	250
Winter - 1999/00	1428	74.7	100.0	22.9	16.0	251
Spring - 2000	1442	75.4	100.0	25.7	17.8	282
Summer - 2000	1404	73.4	100.0	21.4	15.3	235
Fall - 2000	1424	74.5	100.0	23.5	16.5	257
Winter - 2000/01	1430	74.8	100.0	23.0	16.1	253
Spring - 2001	1442	75.4	100.0	25.8	17.9	283
Summer - 2001	1406	73.5	100.0	21.5	15.3	236
Fall - 2001	1424	71.5	100.0	23.2	16.3	255

TABLE A.5 Replacement Energy Data for Catawba 2

Power Pool:	19	Unit Size (MW):	1129
NERC Region:	SERC	Heat Rate (Btu/kWh):	10300
Utility:	NC Municipal Power Agency	Variable Fuel Cost (¢/10^6 Btu):	46

	Seasonal Operating Statistics			Seasonal Production-Cost Increase Due to Short-Term Shutdown		
Season and Year	Generation to Be Replaced (10^6 kWh)	Capacity Factor (%)	% of Season in Service	Total ($\$10^6$)	Average per kWh Replaced (mills/kWh)	Average per Day ($\$10^3$/d)
Winter - 1996/97	1789	72.3	100.0	23.1	12.9	253
Spring - 1997	1806	73.1	100.0	26.9	14.9	294
Summer - 1997	1790	72.4	100.0	23.2	13.0	254
Fall - 1997	1802	72.9	100.0	26.5	14.7	291
Winter - 1997/98	1793	72.5	100.0	24.5	13.6	268
Spring - 1998	1811	73.2	100.0	28.4	15.7	311
Summer - 1998	1795	72.6	100.0	25.2	14.0	276
Fall - 1998	1808	73.1	100.0	29.1	16.1	319
Winter - 1998/99	1795	72.6	100.0	25.6	14.2	280
Spring - 1999	1815	73.4	100.0	31.0	17.1	340
Summer - 1999	1801	72.8	100.0	27.8	15.5	305
Fall - 1999	1815	73.4	100.0	32.1	17.7	351
Winter - 1999/00	1801	72.8	100.0	28.5	15.8	312
Spring - 2000	1819	73.6	100.0	34.8	19.1	381
Summer - 2000	1803	72.9	100.0	29.2	16.2	320
Fall - 2000	1819	73.6	100.0	34.0	18.7	372
Winter - 2000/01	1803	72.9	100.0	29.5	16.3	323
Spring - 2001	1827	73.9	100.0	38.8	21.2	425
Summer - 2001	1808	73.1	100.0	32.0	17.7	351
Fall - 2001	1821	73.6	100.0	34.9	19.2	383

TABLE A.6 Replacement Energy Data for San Onofre 2

Power Pool:	27
NERC Region:	WSCC
Utility:	Southern California Edison Co.
Unit Size (MW):	1070
Heat Rate (Btu/kWh):	10200
Variable Fuel Cost (¢/10^6 Btu):	81

	Seasonal Operating Statistics			Seasonal Production-Cost Increase Due to Short-Term Shutdown		
Season and Year	Generation to Be Replaced (10^6 kWh)	Capacity Factor (%)	% of Season in Service	Total ($\$10^6$)	Average per kWh Replaced (mills/kWh)	Average per Day ($\$10^3$/d)
Winter - 1996/97	1745	74.4	100.0	24.3	13.9	267
Spring - 1997	1750	74.7	100.0	24.5	14.0	269
Summer - 1997	1721	73.5	100.0	26.6	15.5	292
Fall - 1997	1728	73.7	100.0	27.8	16.1	305
Winter - 1997/98	1744	74.4	100.0	24.1	13.8	264
Spring - 1998	1750	74.7	100.0	25.0	14.3	274
Summer - 1998	1722	73.5	100.0	26.6	15.4	291
Fall - 1998	1730	73.8	100.0	27.8	16.1	304
Winter - 1998/99	1747	74.5	100.0	24.3	13.9	266
Spring - 1999	1751	74.7	100.0	25.2	14.4	277
Summer - 1999	1723	73.5	100.0	26.6	15.4	291
Fall - 1999	1731	73.9	100.0	27.8	16.1	305
Winter - 1999/00	1749	74.6	100.0	24.8	14.2	272
Spring - 2000	1752	74.8	100.0	25.6	14.6	280
Summer - 2000	1725	73.6	100.0	26.8	15.6	294
Fall - 2000	1734	74.0	100.0	28.4	16.4	311
Winter - 2000/01	1751	74.7	100.0	25.5	14.6	279
Spring - 2001	1754	74.9	100.0	26.5	15.1	290
Summer - 2001	1727	73.7	100.0	27.5	15.9	301
Fall - 2001	1736	74.1	100.0	29.6	17.0	324

TABLE A.7 Average Annual Replacement Energy Cost Summary

Replacement Energy Cost (mills/kWh)[a]

Power Pool	1997	1998	1999	2000	2001
	Year				
7 (PJM)	15.2	15.3	15.9	17.0	17.7
8 (ComEd)	19.4	19.9	20.9	21.1	22.3
12 (MAPP)	18.1	19.4	21.4	22.9	24.9
14 (NEPOOL)	17.2	17.3	17.4	17.6	17.6
19 (VACAR)	12.6	1[illegible].5	14.8	16.1	17.3
27 (CA-NV)	17.1	17.1	17.2	17.4	17.8

[a] Costs include adjustments for nuclear fuel prices.

TABLE A.8 Replacement Energy Cost Multipliers for Oil and Gas Price Adjustments in Power Pool 7

Season and Year	Replacement Energy Cost Multipliers: 50% Decrease in Oil and Gas Prices	Replacement Energy Cost Multipliers: 50% Increase in Oil and Gas Prices
Winter - 1996/97	.71	1.29
Spring - 1997	.84	1.16
Summer - 1997	.77	1.23
Fall - 1997	.78	1.22
Winter - 1997/98	.69	1.31
Spring - 1998	.84	1.16
Summer - 1998	.77	1.23
Fall - 1998	.78	1.22
Winter - 1998/99	.69	1.31
Spring - 1999	.84	1.16
Summer - 1999	.76	1.24
Fall - 1999	.78	1.22
Winter - 1999/00	.68	1.32
Spring - 2000	.84	1.16
Summer - 2000	.75	1.25
Fall - 2000	.77	1.23
Winter - 2000/01	.68	1.32
Spring - 2001	.83	1.17
Summer - 2001	.74	1.26
Fall - 2001	.77	1.23

TABLE A.9 Replacement Energy Cost Multipliers for Oil and Gas Price Adjustments in Power Pool 8

	Replacement Energy Cost Multipliers	
Season and Year	50% Decrease in Oil and Gas Prices	50% Increase in Oil and Gas Prices
Winter - 1996/97	.87	1.13
Spring - 1997	.85	1.15
Summer - 1997	.87	1.13
Fall - 1997	.83	1.17
Winter - 1997/98	.89	1.11
Spring - 1998	.84	1.16
Summer - 1998	.87	1.13
Fall - 1998	.82	1.18
Winter - 1998/99	.88	1.12
Spring - 1999	.83	1.17
Summer - 1999	.86	1.14
Fall - 1999	.81	1.19
Winter - 1999/00	.88	1.12
Spring - 2000	.82	1.18
Summer - 2000	.86	1.14
Fall - 2000	.81	1.19
Winter - 2000/01	.87	1.13
Spring - 2001	.82	1.18
Summer - 2001	.85	1.15
Fall - 2001	.79	1.21

TABLE A.10 Replacement Energy Cost Multipliers for Oil and Gas Price Adjustments in Power Pool 12

	Replacement Energy Cost Multipliers	
Season and Year	50% Decrease in Oil and Gas Prices	50% Increase in Oil and Gas Prices
Winter - 1996/97	.74	1.26
Spring - 1997	.85	1.15
Summer - 1997	.84	1.16
Fall - 1997	.72	1.28
Winter - 1997/98	.67	1.33
Spring - 1998	.79	1.21
Summer - 1998	.82	1.18
Fall - 1998	.81	1.19
Winter - 1998/99	.72	1.28
Spring - 1999	.83	1.17
Summer - 1999	.80	1.20
Fall - 1999	.68	1.32
Winter - 1999/00	.71	1.29
Spring - 2000	.83	1.17
Summer - 2000	.79	1.21
Fall - 2000	.66	1.34
Winter - 2000/01	.64	1.36
Spring - 2001	.77	1.23
Summer - 2001	.76	1.24
Fall - 2001	.77	1.23

TABLE A.11 Replacement Energy Cost Multipliers for Oil and Gas Price Adjustments in Power Pool 14

	Replacement Energy Cost Multipliers	
Season and Year	50% Decrease in Oil and Gas Prices	50% Increase in Oil and Gas Prices
Winter - 1996/97	.68	1.32
Spring - 1997	.84	1.16
Summer - 1997	.63	1.37
Fall - 1997	.77	1.23
Winter - 1997/98	.70	1.30
Spring - 1998	.83	1.17
Summer - 1998	.64	1.36
Fall - 1998	.78	1.22
Winter - 1998/99	.69	1.31
Spring - 1999	.85	1.15
Summer - 1999	.65	1.35
Fall - 1999	.77	1.23
Winter - 1999/00	.71	1.29
Spring - 2000	.85	1.15
Summer - 2000	.66	1.34
Fall - 2000	.78	1.22
Winter - 2000/01	.71	1.29
Spring - 2001	.85	1.15
Summer - 2001	.66	1.34
Fall - 2001	.78	1.22

TABLE A.12 Replacement Energy Cost Multipliers for Oil and Gas Price Adjustments in Power Pool 19

Season and Year	Replacement Energy Cost Multipliers: 50% Decrease in Oil and Gas Prices	Replacement Energy Cost Multipliers: 50% Increase in Oil and Gas Prices
Winter - 1996/97	.89	1.11
Spring - 1997	.92	1.08
Summer - 1997	.89	1.11
Fall - 1997	.91	1.09
Winter - 1997/98	.86	1.14
Spring - 1998	.92	1.08
Summer - 1998	.88	1.12
Fall - 1998	.90	1.10
Winter - 1998/99	.85	1.15
Spring - 1999	.92	1.08
Summer - 1999	.88	1.12
Fall - 1999	.89	1.11
Winter - 1999/00	.87	1.13
Spring - 2000	.89	1.11
Summer - 2000	.[illegible]7	1.13
Fall - 2000	.87	1.13
Winter - 2000/01	.87	1.13
Spring - 2001	.84	1.16
Summer - 2001	.81	1.19
Fall - 2001	.87	1.13

TABLE A.13 Replacement Energy Cost Multipliers for Oil and Gas Price Adjustments in Power Pool 27

Season and Year	Replacement Energy Cost Multipliers	
	50% Decrease in Oil and Gas Prices	50% Increase in Oil and Gas Prices
Winter - 1996/97	.88	1.12
Spring - 1997	.86	1.14
Summer - 1997	.69	1.31
Fall - 1997	.69	1.31
Winter - 1997/98	.84	1.16
Spring - 1998	.84	1.16
Summer - 1998	.69	1.31
Fall - 1998	.70	1.30
Winter - 1998/99	.87	1.13
Spring - 1999	.84	1.16
Summer - 1999	.69	1.31
Fall - 1999	.70	1.30
Winter - 1999/00	.83	1.17
Spring - 2000	.84	1.16
Summer - 2000	.69	1.31
Fall - 2000	.69	1.31
Winter - 2000/01	.81	1.19
Spring - 2001	.84	1.16
Summer - 2001	.69	1.31
Fall - 2001	.69	1.31

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11. ABSTRACT (200 words or less)

This report updates previous estimates of replacement energy costs for potential short-term shutdowns of 109 U.S. nuclear electricity units. This information was developed to assist the U.S. Nuclear Regulatory Commission (NRC) in its regulatory impact analyses, specifically those that examine the impacts of proposed regulations requiring retrofitting of or safety modifications to nuclear reactors. Such actions might necessitate shutdowns of nuclear power plants while these changes are being implemented. The change in energy cost represents one factor that the NRC must consider when deciding to require a particular modification. Cost estimates were derived from probabilistic production cost simulations of pooled utility system operations. Factors affecting replacement energy costs, such as random unit failures, maintenance and refueling requirements, and load variations, are treated in the analysis. This report describes an abbreviated analytical approach as it was adopted to update the cost estimates published in NUREG/CR-4012, Vol. 3. The updates were made to extend the time frame of cost estimates and to account for recent changes in utility system conditions, such as change in fuel prices, construction and retirement schedules, and system demand projections.

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