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Replacement Energy Costs for Nuclear Electricity-Generating Units in the United States

Prepared by J. C. VanKuiken, W. A. Buehring, K. A. Guziel

Argonne National Laboratory

Prepared for
U.S. Nuclear Regulatory
Commission

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ABSTRACT

Seasonal replacement energy costs are estimated for potential short-term shutdowns of 108 nuclear electricity-generating units. These estimates were developed to help the Nuclear Regulatory Commission establish regulatory policies, particularly those requiring safety modifications that might necessitate temporary reactor shutdowns. 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. Seasonal costs are presented for the two-year period beginning with fall 1984 and ending with summer 1986.

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FOREWORD

The Cost Analysis Group within the U.S. Nuclear Regulatory Commission Office of Resource Management is available to help users apply the results presented here. Please contact Richard Hartfield, Cost and Management Support Branch, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555, (202) 492-7834. The data on which this work is based are expected to be updated periodically so that costs can be estimated beyond 1986.

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

by

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

SUMMARY

PURPOSE

This report presents estimates of replacement energy costs for nuclear electricity-generating units in the United States. The estimates can be applied to short-term outages between the fall of 1984 and the summer of 1986. The research reported here was sponsored by the Cost Analysis Group of the U.S. Nuclear Regulatory Commission (NRC). The information was developed principally for the NRC to use in its regulatory impact analyses, specifically analyses that examine the impacts of proposed regulations that require retrofitting or safety modifications of nuclear reactors. Such actions might necessitate shutdowns of nuclear power plants while changes are implemented. These estimates may also be useful in other NRC licensing and regulatory decisions.

RESULTS

Replacement energy costs were calculated for all 108 nuclear generating units expected to be operating in the study period. Results are given in Table S.1 and grouped according to the nine regions of the North American Electrical Reliability Council (NERC). A map of these regions is shown in Fig. S.1.

For most regulatory analyses, Table S.1 should provide an adequate basis for estimating a replacement energy cost for a specific outage. The analyst must independently estimate the expected length and timing of the short-term outage. For example, if a proposed regulation were expected to cause the Comanche Peak 1 reactor to be shut down for two weeks in the fall of 1985 for safety modifications, the analyst would multiply 14 times the daily replacement energy cost for Comanche Peak for fall 1985 ($709,000) given in Table S.1. The resulting replacement energy cost of $9,926,000 is in 1984 constant dollars. If the analyst is expressing costs and benefits in 1984 present worth, this value must be discounted one year by the real discount rate.

APPLYING THE RESULTS

The analyst is urged to review this report in its entirety to better appreciate the assumptions on which these estimates are based. Greater care should be used in applying these estimates to shutdowns of a year or more because in such cases utilities would probably seek out more-optimum solutions to the loss of a nuclear reactor. Long-term adjustments of this nature are not included in this analysis.

TABLE S.1 Average Daily Replacement Energy Cost for 108 Nuclear Reactors, by Season[a] (10^3 undiscounted 1984 dollars per day)

NERC Region and Unit[b]	Fall 1984	Winter 1984/85	Spring 1985	Summer 1985	Fall 1985	Winter 1985/86	Spring 1986	Summer 1986
ECAR								
Beaver Valley 1	307	282	276	271	277	258	256	247
Beaver Valley 2	-	-	-	-	-	-	254	254
Big Rock Point 1	37	36	32	29	33	31	30	28
Donald C. Cook 1	302	292	289	288	290	283	284	283
Donald C. Cook 2	315	304	301	299	301	294	295	293
Davis-Besse 1	312	286	279	273	279	260	257	248
Enrico Fermi 2	-	610	516	479	552	541	503	461
Midland 2	-	-	-	-	-	-	-	334
Palisades 1	365	347	299	273	311	303	291	262
Perry 1	-	-	374	381	387	363	358	345
ERCOT								
Comanche Peak 1	-	727	720	700	709	716	711	685
Comanche Peak 2	-	-	-	-	-	-	-	684
MAAC								
Calvert Cliffs 1	501	486	485	351	449	475	479	364
Calvert Cliffs 2	501	486	485	351	449	475	479	364
Limerick 1	-	-	589	448	574	608	612	461
Oyster Creek 1	392	377	376	275	351	369	373	285
Peach Bottom 2	594	578	578	407	533	564	570	422
Peach Bottom 3	585	569	569	401	524	556	561	415
Salem 1	645	629	629	454	582	616	620	467
Salem 2	661	646	644	466	598	632	636	478
Susquehanna 1	617	601	601	433	556	588	593	447
Susquehanna 2	697	613	613	442	568	599	605	456
Three Mile Island 1	-	433	448	322	416	439	444	336
MAIN								
Braidwood 1	-	-	-	-	-	-	399	367
Byron 1	-	711	602	478	601	638	495	367
Byron 2	-	-	-	-	-	-	399	367
Callaway 1	-	361	364	321	325	386	392	324
Dresden 2	457	467	411	327	412	438	336	248
Dresden 3	454	467	411	328	413	437	337	248
Kewaunee 1	102	95	90	84	91	93	91	83
LaSalle 1	680	697	619	501	618	654	516	393
LaSalle 2	681	697	618	501	618	654	515	393
Point Beach 1	127	120	115	110	116	118	116	108
Point Beach 2	127	120	115	110	116	118	116	108
Quad-Cities 1	359	374	356	261	338	357	277	201
Quad-Cities 2	359	373	356	261	338	356	274	201
Zion 1	616	632	557	444	555	590	457	339
Zion 2	616	632	557	444	555	590	457	339
MAPP								
Duane Arnold 1	90	92	122	73	116	113	100	71
Cooper 1	114	111	155	84	144	137	123	81
Fort Calhoun 1	60	63	88	47	82	80	68	45
LaCrosse 5	7	8	12	6	10	10	8	6
Monticello 1	100	102	133	83	126	123	110	81

TABLE S.1 (Cont'd)

NERC Region and Unit[b]	Fall 1984	Winter 1984/85	Spring 1985	Summer 1985	Fall 1985	Winter 1985/86	Spring 1986	Summer 1986
MAPP (cont'd)								
Prairie Island 1	90	92	122	74	116	113	100	72
Prairie Island 2	90	92	121	74	115	112	100	72
NPCC								
Fitzpatrick 1	617	620	601	513	566	616	564	502
Ginna 1	330	329	322	271	299	331	300	264
Haddam Neck 1	438	439	472	412	436	422	408	388
Indian Point 2	626	629	608	515	572	624	570	503
Indian Point 3	700	705	679	577	642	699	637	564
Maine Yankee 1	647	650	701	608	645	628	623	577
Millstone 1	514	515	553	483	512	496	486	457
Millstone 2	670	674	728	629	668	651	649	596
Millstone 3	-	-	-	-	-	-	908	803
Nine Mile Point 1	418	419	406	341	377	417	378	331
Pilgrim 1	550	552	591	519	549	532	523	491
Seabrook 1	-	-	-	-	-	-	-	856
Shoreham 1	-	-	-	490	543	592	540	477
Vermont Yankee 1	388	388	416	365	386	371	361	344
Yankee Rowe 1	132	131	140	125	131	126	120	116
SERC								
Browns Ferry 1	306	289	292	280	297	283	281	276
Browns Ferry 2	306	289	292	280	297	283	281	276
Browns Ferry 3	306	289	292	280	297	283	281	276
Brunswick 1	389	283	397	304	394	267	335	280
Brunswick 2	389	283	397	304	394	267	335	280
Catawba 1	-	-	-	460	574	401	512	422
Crystal River 3	526	437	488	487	496	433	518	492
Farley 1	257	296	257	281	559	306	568	296
Farley 2	261	295	275	282	568	314	575	300
Harris 1	-	-	-	-	-	-	391	329
Hatch 1	262	309	265	284	548	300	555	298
Hatch 2	265	312	297	285	555	309	560	301
McGuire 1	598	452	624	475	593	414	528	436
McGuire 2	599	452	624	475	593	414	528	436
North Anna 1	438	325	452	346	446	304	382	319
North Anna 2	445	331	459	352	453	309	386	324
Oconee 1	421	311	435	331	429	290	366	305
Oconee 2	421	311	435	331	429	290	366	305
Oconee 3	421	311	435	331	429	290	366	305
Robinson 2	346	254	348	275	350	242	300	253
Sequoyah 1	325	306	310	297	316	300	298	293
Sequoyah 2	325	306	310	297	316	300	298	293
St. Lucie 1	489	400	451	450	459	396	481	455
St. Lucie 2	468	382	432	431	439	378	460	434
Surry 1	368	264	376	285	373	249	315	262
Surry 2	368	264	376	285	373	249	315	262
Turkey Point 3	464	391	432	435	440	388	457	436
Turkey Point 4	464	391	432	435	440	388	457	436
V.C. Summer 1	451	336	466	357	459	313	391	328
Watts Bar 1	324	311	314	301	321	305	302	297

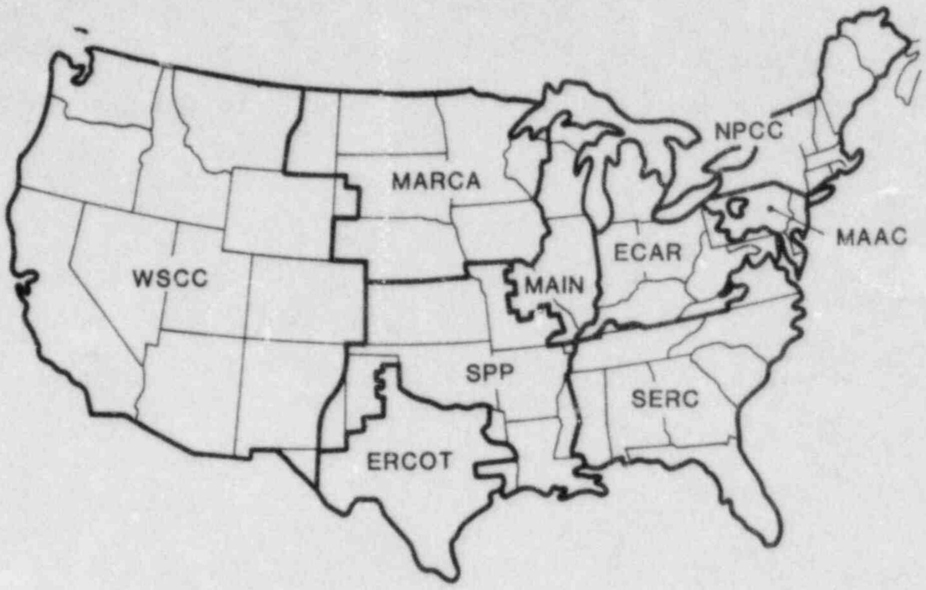
TABLE S.1 (Cont'd)

NERC Region and Unit[b]	Fall 1984	Winter 1984/85	Spring 1985	Summer 1985	Fall 1985	Winter 1985/86	Spring 1986	Summer 1986
SPP								
Arkansas Nuclear One 1	369	372	357	367	354	360	347	355
Arkansas Nuclear One 2	379	382	366	377	363	369	356	365
Grand Gulf 1	548	557	546	549	575	540	548	535
River Bend 1	-	-	-	-	-	402	389	397
Waterford 3	-	513	492	507	489	497	478	491
Wolf Creek 1	-	-	444	381	419	474	449	387
WSCC								
Diablo Canyon 1	922	897	813	833	893	868	779	803
Diablo Canyon 2	-	-	751	851	912	887	793	819
Fort St. Vrain 1	66	47	46	40	70	44	81	39
Hanford N	360	108	72	296	525	122	67	311
Palo Verde 1	-	862	781	889	828	847	764	850
Palo Verde 2	-	-	-	-	828	847	764	849
Rancho Seco 1	739	720	653	671	716	696	618	650
San Onofre 1	326	324	283	293	314	288	262	283
San Onofre 2	824	800	719	738	796	778	686	708
San Onofre 3	824	800	719	738	796	778	686	708
Trojan 1	517	147	86	370	672	167	80	401
WNP 2	535	155	88	378	684	172	82	410

[a]Season definitions: Spring, March through May; Summer, June through August; Fall, September through November; Winter, December through February.

[b]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, and
WSCC = Western Systems Coordinating Council.

The analyst must also consider the planned outages of the reactor (scheduled maintenance and refueling) and the possibility of shifting these scheduled outages to coincide with an NRC-imposed shutdown. To the extent that planned outages coincide with mandated shutdowns, the replacement energy cost attributable to the NRC-imposed shutdown is effectively reduced. Although the results in Table S.1 are based on nominal maintenance and refueling schedules for all units, costs for each unit have been adjusted to reflect the full costs of shutdown, had that unit been in service for each entire season after its start-up date. This adjustment allows the analyst to examine alternative shutdown timings without having to assume a predetermined maintenance schedule for the reactor of interest. As a result, the seasonal results cannot be summed to determine annual costs. Section 3 describes a procedure for estimating annual shutdown costs under alternative maintenance and refueling assumptions.



ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interpool Network

MARCA
Mid-Continent Area Reliability Coordination Agreement

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southeast Power Pool

WSCC
Western Systems Coordinating Council

FIGURE S.1 North American Electric Reliability Council (NERC) Regions

Some planned reactors may not meet announced start-up plans. However, it was necessary to use the anticipated dates as of the time of final simulations (approximately June 1984). For small changes in start-up times, the tabulated results can be adjusted according to guidelines described in Sec. 3. For longer delays in start-ups, simple adjustments are more difficult to perform and selected updates of the analyses may be warranted. Appendix A lists the reactor start-up dates assumed in this analysis.

Finally, the effect of multiple shutdowns and the availability of additional economy purchases for replacement energy costs are not fully reflected in these results. An example in App. B illustrates the potential for multiple shutdowns to increase replacement energy costs. However, the magnitude of these effects is expected to be predominantly case-specific, and care should be taken in applying the results for shutdowns in one generating system to other generating systems. Economy purchases from outside the power pool (a group of closely linked utilities) are assumed to remain fairly constant in short-term shutdowns. Instead, higher-priced emergency purchases are assumed to satisfy any energy demands that cannot be met within the generating system of interest, given that scheduled purchases remain fixed. If significant sources of additional economy purchases were made available during a shutdown, the overall costs of replacement energy would be reduced.

1 INTRODUCTION

This report presents estimates of seasonal replacement energy costs for short-term outages of all 108 U.S. nuclear electricity-generating units that are operating or are expected to be operating by the summer of 1986. This information was developed principally for the U.S. Nuclear Regulatory Commission (NRC) to use in its regulatory impact analyses, specifically analyses that examine the impacts of proposed regulations requiring retrofitting or safety modifications of nuclear reactors. Such actions might necessitate shutdowns of nuclear power plants while changes are implemented. The change in energy cost represents one factor the NRC must consider when deciding whether to require a particular modification.

Replacement energy cost refers to the change in generating system production cost that results from shutting down the reactor of interest. The change in production cost is determined from the difference between the total variable costs (variable fuel cost, variable operation and maintenance cost, and purchased energy cost) 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.

The production-cost results presented in this report are based on probabilistic simulations of power pools rather than individual utilities. Power pools range from groups of tightly linked utilities with central dispatch of generating units to groups of nearly independent utilities with cooperative agreements for power interchange under various circumstances. Power pool simulations yield more realistic estimates of replacement energy costs than do individual utility simulations because economy energy exchanges within each pool are automatically taken into account. In addition, any transfer payments between utilities are eliminated (e.g., payments for energy supplied that pay not only the seller's cost of production but also 50% of the savings incurred because the buying utility did not generate the electricity itself).

The replacement energy cost for a particular hypothetical reactor shutdown was determined from two production-cost simulations, as shown in Fig. 1.1: (1) a case in which all units, 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 is used in both cases. This consistency is important because results are not meaningful unless assumptions about key parameters (e.g., load growth, fuel prices, expansion plans) are identical in both cases. Maintenance schedules for all units in the power pool were also the same in both cases. Replacement energy costs were determined on a seasonal basis over the two-year interval of fall 1984 through summer 1986 (September 1984-August 1986).

A 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 production-cost model because so many complex factors influence costs. These factors include random forced outages of generating units, variation of system load over time, maintenance and refueling schedules, loading order,

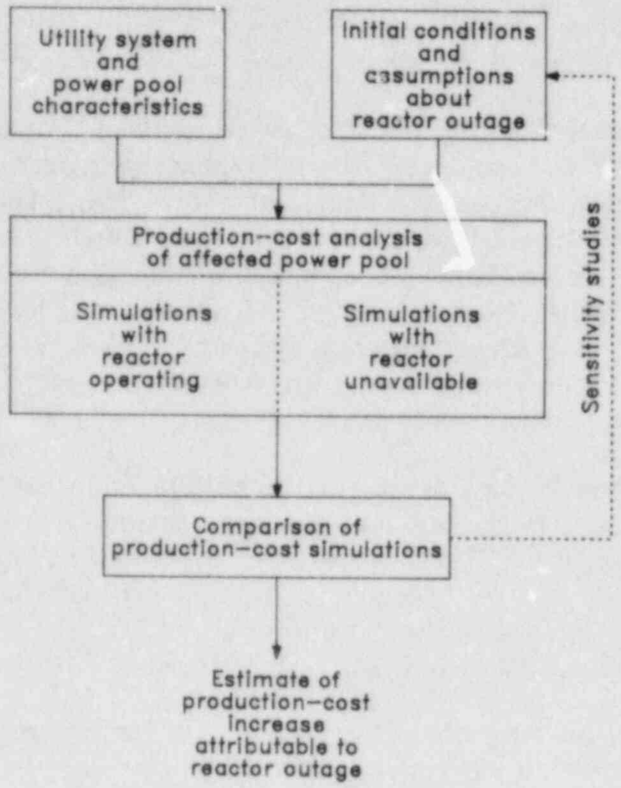


FIGURE 1.1 Procedure for Determining Production-Cost Increases due to Reactor Outage

representation of generating units with limited energy supply (e.g., hydroelectric units), and various practical operating conditions. Some of the power pools simulated comprise several hundred generating units. Thus, a unit-by-unit determination of the additional generation made necessary by a reactor shutdown is a nontrivial problem.

A more detailed portrayal of the procedure used for the calculations is shown in Fig. 1.2. The Automated Data Assembly Package (ADAP) was used to prepare very detailed data sets for each case study. These data sets were input to the production-cost model ICARUS (Investigation of Costs and Reliability in Utility Systems), which is an efficient algorithm for calculating production costs for large utility systems and groups of utility systems. Two complete simulations were performed with these procedures for all 108 nuclear generating units scheduled to be operating before summer 1986: one simulation with the reactor of interest operating and one with it shut down.

The replacement energy costs presented in this report are more accurate than estimates prepared with informal estimating techniques but less accurate than costs determined from a comprehensive study of a particular reactor. A comprehensive study of a short-term outage for a particular reactor would probably be based on more-detailed, specific data about factors that can affect replacement energy cost, such as actual maintenance schedules and reactor capacity factors. For example, the results presented in Sec. 4 are based on the assumption that all reactors have approximately the

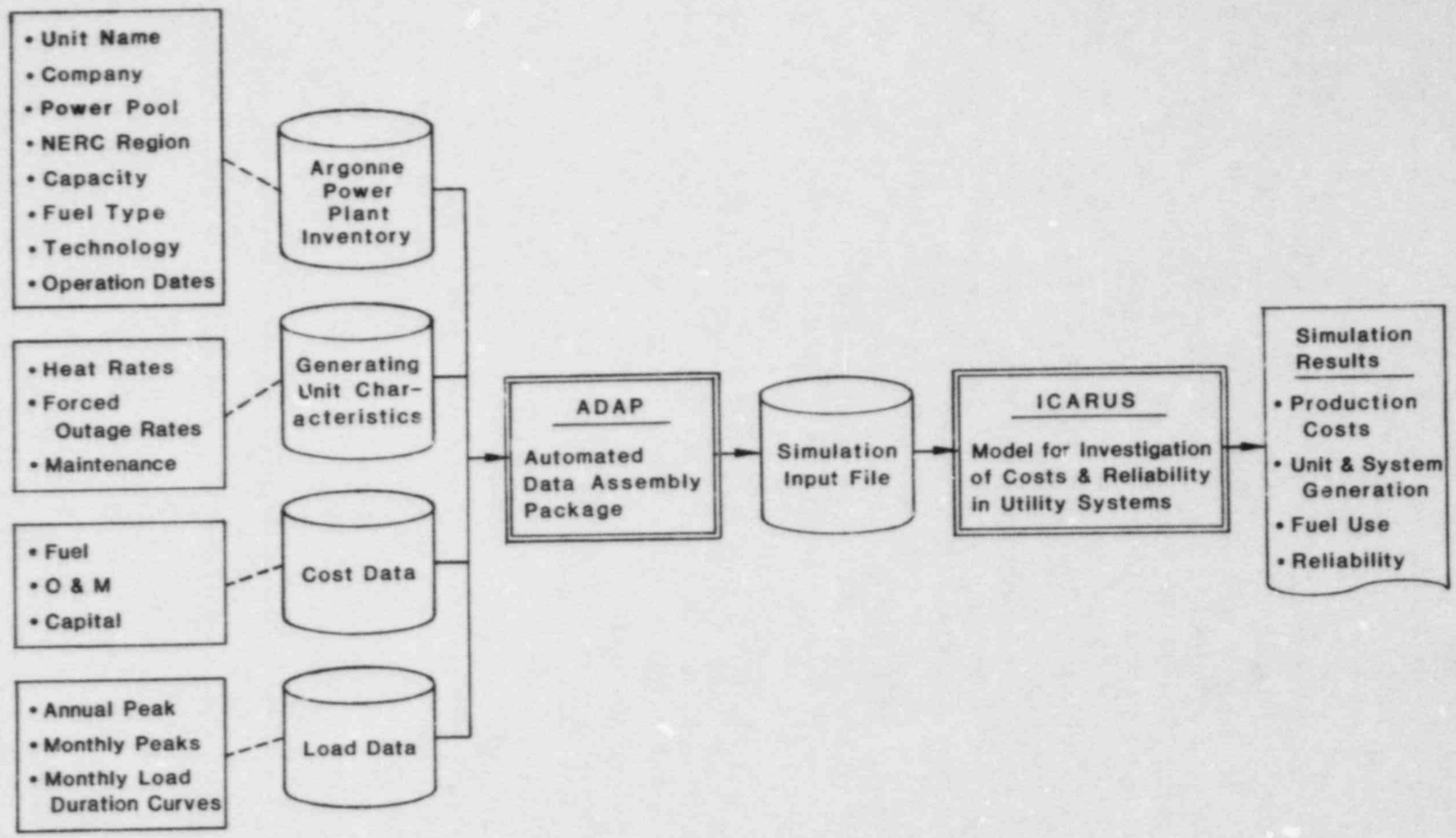


FIGURE 1.2 Major Components of the Electrical Utility System Data Base and Modeling Package

same annual capacity factor. In some cases, different reactor capacity factors may be justified, especially over a short period. Changing the capacity factor will affect the replacement energy cost for the designated reactor as well as for every other reactor in that power pool.

Another note of caution is given about assumed dates of commercial operation for new units. At the time this study was performed, the most up-to-date projections were obtained from North American Electric Reliability Council (NERC) reports, published in April 1984.[1-9] As time passes, however, some reactors could encounter additional delays. The results for such reactors can easily be modified by assuming no replacement energy cost for periods before the revised start-up date. However, costs for other reactors in the same power pool are based on the earlier commercial operation date. Therefore, a delay in commercial operation of any reactor will tend to increase replacement energy costs for other reactors in the same power pool.

The cautionary notes listed above demonstrate that there is no substitute for an up-to-date, detailed production-cost analysis to determine replacement energy costs. Nevertheless, the NRC needs reasonable estimates for replacement energy costs as one input to regulatory decision making. These estimates should be sensitive to important variables, such as seasonal variation of load, mix of generating capacity in the power pool, fuel prices, performance characteristics of generating units (e.g., heat rates, forced outages), and the effects of maintenance scheduling. The results presented here serve that purpose.

The remainder of the report is organized as follows. Section 2 outlines the method of analysis, some important assumptions, and key references. Section 3 provides a brief characterization of every power pool with an operating nuclear unit, information for interpreting the results given in Sec. 4, and some sample calculations to demonstrate how those results can be manipulated. Section 4 presents the results for each nuclear unit. A one-page table is devoted to each of the 108 reactors. Section 5 lists some observations based on the results of the study. The appendixes list actual operating data for U.S. reactors and present the results of one case study in which multiple reactors in the same power pool are shut down.

2 METHODS OF ANALYSIS

This section briefly describes the modeling tools, data sources, and representations that were used to estimate replacement energy costs for short-term reactor shutdowns. Only summary information is provided because this study incorporated many parameters. Wherever possible, references are noted to provide background information and sources of data. Key assumptions that have a major influence on estimated costs are highlighted.

2.1 MODELING TOOLS: AN OVERVIEW

Probabilistic production-cost and reliability simulations of electrical generating systems were used for estimating replacement energy costs. Two modeling tools formed the basis for most of the analysis. One is ICARUS, which performs the probabilistic simulations for a particular generating system representation.[10] The other is ADAP, an automated data assembly package that contains data preparation features and an extensive data base of electric utility systems.

2.1.1 Production-Cost and Reliability Analysis

The ICARUS model is similar in most respects to conventional production-cost and reliability models used to examine electric utility performance and costs. It probabilistically treats system load variations and unscheduled (forced) outages. Maintenance schedules (and reactor refueling schedules), heat rates, costs, and forced outages are considered for each unit. The model also includes representations for operational criteria or constraints such as unit loading priorities and spinning reserves.

The primary difference between ICARUS and more-conventional production-cost models is ICARUS's greater computational efficiency, which allows large systems to be simulated at reasonable costs. This efficiency was an important consideration in this study because all 108 reactors had to be examined individually in the context of operations within 21 different electric power pools. Some power pools consisted of nearly 300 generating units, all of which were treated separately in the calculations of system generation, fuel use, and costs. Furthermore, each reactor case study consisted of simulations for two years of study divided into 24 equal periods per year.

The ICARUS model uses a simplified calculation of the energy commitments for individual units and provides a high degree of accuracy and stability compared to conventional methods.[10] With the computational advantages of this approach, power pools can be characterized in sufficient detail for the examination of replacement energy costs. 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.

Replacement energy costs were determined for each reactor by comparing results from two simulations, one in which the unit is available except for forced outages and maintenance, and one in which the unit is shut down for the entire study period. Differences in total production costs were then calculated for each season and converted to units of mills per kilowatt-hour and average dollars per service day. These conversions were based on the kilowatt-hours of generation from the unit in question and the date of commercial operation assumed for new units. Costs for periods of planned maintenance were then adjusted to reflect the shutdown costs that would have occurred if the unit had not been scheduled out of service (see Sec. 2.3.2). This step eliminates gaps in the cost results caused by assuming a particular maintenance schedule, and it allows the results to be applied to alternative timings of reactor shutdowns.

2.1.2 Electrical Generating System Data

A data base of electrical generating systems was developed to provide the necessary representations for simulating power pools. One portion of the data base, the Argonne Power Plant Inventory, contains a comprehensive inventory of individual generating units in the United States. Information on approximately 13,000 facilities is stored in the data base. The U.S. Department of Energy's Generating Unit Reference File (GURF) was used as a starting point for constructing the inventory.[11]

The original GURF file was substantially modified to correct errors and update the information according to recent publications. The GURF data for each unit were compared with similar data from the NERC 1983 regional reports on bulk power supply[1-9] to verify that the inventory listed all units and correctly reported the major characteristics of each unit.* The primary characteristics of interest included unit size and type, primary fuel type, current operating status (e.g., in service, retired, under construction), and the expected dates of installation or retirement.

Each unit in the inventory was also cross-referenced by company name, power pool, and NERC region.** The cross-references allow system representations to be based on single utilities, groups of utilities, power pools, or entire NERC regions. Replacement energy costs in this study were based on power pool simulations to account for potential energy exchanges between centrally dispatched or coordinated utility systems. Therefore, the reported costs are not those of a single utility, but instead the net costs in the larger context of pooled operations.

The power plant inventory is coupled with a complementary data base of operational characteristics for generating units, load data, and data assembly software that facilitates the preparation of coded system representations. Operational characteristics for generating units include forced outage rates, scheduled maintenance requirements (i.e., weeks required to be out of service), heat rates, fuel costs, variable operation and

*The 1984 editions of the NERC reports were published in time to be used for updating load projections and planned commercial operation dates, but not in time to review the entire inventory.

**Power pools and NERC regions are defined in Sec. 2.3.

maintenance (O&M) costs, and fixed O&M costs. Load data include monthly load duration curves that match published load projections. Sources of data for these parameters are identified in Sec. 2.2.

The entire collection of utility data and software is called ADAP, for Automated Data Assembly Package. In response to user-defined commands, the package selects the appropriate set of generating units and loads, assigns the operational characteristics, and formats the coded information for direct use by the production-cost and reliability model, ICARUS. The user can then adjust the information to include case-specific factors or to depart from portions of the default parameters.

2.2 PRIMARY DATA SOURCES AND COST ASSUMPTIONS

This section identifies the primary sources of data used to determine installed capacity and assign operational characteristics, costs, loads, and external energy transfers. Because this analysis incorporated many parameters, only the most critical values are reported here. Most parameters not explicitly tabulated in this report can be found or derived from the cited references.

2.2.1 Power Plant Inventory

As previously mentioned, unit data for the Argonne Power Plant Inventory were verified primarily on the basis of the 1983 reports on bulk power supply from each NERC region.[1-9] Additional efforts were made to resolve fuel designations for "dual-fueled" steam units. These units are designed with the capability for using two fuels, usually natural gas and residual oil. In some regions the dual-fueled capacity represented a significant fraction of the total capability and the "primary" fuel designation did not adequately characterize the current fuel option. For these regions, unit-specific fuel use reports were consulted to assign the appropriate fuel type.[12]

Commercial start-up dates for nuclear reactors were taken from the 1984 editions of the regional North American Electric Reliability Council (NERC) reports,[1-9] since they were published in time to permit a limited number of updates to the inventory. For a few cases in which the start-up dates listed in *Nuclear News*[13] were later than those in the NERC reports, the later dates were interpreted as an indication of recently encountered delays in construction schedules. In these cases the later dates were adopted. Capacities for nuclear units were changed to conform with the sizes reported by the NRC.[14,15] These values were selected to match the standard reference values likely to be used by the NRC staff. However, in a few cases these values do not conform with the definition for maximum dependable capacity (net megawatts), which should be the net dependable capacity rating for either winter or summer, whichever is smaller.

The NRC Summary Information Report[14] adopts the design capacity for planned units, a fact that may explain some of the differences between it and NERC sources. For example, the NRC report shows the two Braidwood reactors as being 1120-MW units, while the NERC report from Mid-America Interpool Network[4] rates them at 1090 MW for the summer and 1120 MW for the winter. Differences also occur for operating reactors such as Unit 1 of the Duane Arnold plant. The NERC report from Mid-Continent Area Power Pool[5] rates that unit at 500 MW net dependable capacity in summer and 510 MW in winter. The NRC report, *Licensed Operating Reactors,*[15] rates the Duane Arnold unit at 515 MW. Although there were some discrepancies such as these, the NRC capacities were adopted and used throughout the two-year study period without seasonal adjustments.

Appendix A lists the reactors considered in this study along with their assumed capacities, operation dates, and, for reference, their historical cumulative capacity factors. Historical capacity factors were not used in this study (see Secs. 2.2.2 and 2.3.1).

2.2.2 Generating Unit Characteristics

Unit operating parameters that must be specified include forced outage rates (FORs), heat rates, and routine scheduled maintenance requirements (which include refueling periods for nuclear units as well as the standard unit maintenance). For nonnuclear technologies, these parameters were assigned as a function of unit type (e.g., steam turbine, diesel, gas turbine), unit size, fuel type, emission control type, and regional location. Thus, while the operating characteristics are somewhat generic because they are based on regional or national averages, they are sensitive to the key factors that affect unit performance. In the case of nuclear facilities, standard values for FORs and maintenance were adopted, while heat rates were based on unit-specific data.

Forced outage rates were primarily derived from the NERC annual report on equipment availability.[16] The "equivalent forced outage rate" was used in the calculations to account for partial outages, or deratings, as well as full unscheduled outages. These outage rates vary by unit type, unit size, and fuel type. For coal units with flue-gas desulfurization systems, outage rates were adjusted to reflect the additional impact that emission controls have on unit failures. The equivalent FOR for nuclear units (of all sizes) was fixed at 21.7%, in agreement with data from Electric Power Research Institute (EPRI).[17] When coupled with the maintenance and loading assumptions described later in this report, the 21.7% FOR yields a more conservative estimate of annual availability than the overall NERC average FOR of 17.4%. With a 21.7% FOR, the maximum annual capacity factor for nuclear units ranges between 57% and 62%. The lower FOR of 17.4% would allow maximum annual capacity factors to range between 60% and 65%.

Heat rates for coal units were assigned from EPRI data that vary according to region and unit size.[18] Data for other types of nonnuclear units vary by size and fuel type but not by region. Regional variations for coal units reflect differences in coal quality (e.g., ash, sulfur, and Btu content) that typify the fuel supply patterns for various regions.

Heat rates for existing nuclear units were assigned on the basis of plant-specific data from Federal Energy Regulatory Commission (FERC) Form 1 (Dec. 1982).[19] Using historical information to assign unit-specific rates accounts, in part, for variations that occur as a result of reactor design differences. While heat rates for a given unit can change from year to year as a result of different operating conditions, these variations are expected to be less significant than those arising from differences in reactor designs.

In cases where data were missing or capacity factors were too low to provide reliable estimates, the heat rates reported for 1981 were selected.[20] The few remaining unresolved cases were assigned heat rates on the basis of average data from the U.S. Department of Energy's (DOE's) *Update* on nuclear data and summary information.[21] Because Form 1 data are reported for plants, not units, identical heat rates were assigned to multiple units at a given site.

Heat rates for planned nuclear units were chosen to match those of similar existing units in the same utility or power pool. If there were no existing units with similar design characteristics in the same power pool, then heat rates from similar units in a neighboring pool were adopted. The final heat rate assignments are shown in the tables for each unit in Sec. 4. The values range from 10,275 to 14,090 Btu/kWh.

With a few exceptions, scheduled maintenance characteristics were taken from EPRI estimates.[17,18] These estimates vary according to unit type and fuel type but are uniform across all regions of the United States. Steam units fueled by coal, oil, or gas also show variations with unit size, whereas other types of units (e.g., diesels, combustion turbines) have uniform maintenance specified for all unit sizes. On the basis of NERC data, existing nuclear units were assigned 76 days of maintenance per year,* which includes allowances for both refueling and routine servicing. This planned outage period, which is longer than EPRI's estimate of 47 days, provides a more reasonable average for the maximum annual capacity factor (62%) when coupled with the forced outage rate assumption of 21.7%. Other simulated loading constraints result in nominal capacity factors of about 57%. Routine maintenance and refueling for new units is not scheduled until their second year of operation.

2.2.3 Overview of Cost Assumptions

All costs presented in this report are given in undiscounted 1984 dollars. The primary components include variable costs for fuel, O&M, and emergency purchases. Capital costs, fixed O&M costs, and the fixed component of nuclear fuel costs are assumed to be constant over short-term shutdowns for a given reactor.** Hence these components do not contribute to the total costs of replacement energy. This assumption would not hold under longer-term shutdown conditions that could affect (1) fixed costs for the reactor in question or (2) capital expenditures for new or accelerated construction. Zero real escalation rates were assumed for all cost components except nuclear O&M costs. Unlike other cost components, nuclear O&M costs have escalated rapidly during the recent past.

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*The NERC outage factor of 19.72%/yr actually translates into 72 d/yr. However, in the context of 24-period/yr simulations, a maintenance duration of 5 periods results in the closest approximation (76 d) to the NERC estimate.

**Fuel costs for fossil-fuel-fired units are assumed to have no fixed cost component.

Fossil fuel prices for each power pool were based on a summary of unit-specific costs for facilities of 50 MW or larger.[12] The prices that were used are tabulated with the power pool characterizations in Sec. 3. Differentiating costs by power pool is important because the pools differ significantly in production, processing, and transportation costs, as well as in contractual purchase agreements. The *Report of Cost and Quality of Fuels for Electric Plants* (Ref. 12) summarizes the information reported on FERC Form 423, a mandatory report submitted monthly to the DOE's Energy Information Administration. In a few cases where power pool areas conform to state boundaries, the averages were obtained directly from *Electric Power Monthly.*[22] This DOE report tabulates the FERC Form 423 data in state and regional summaries for major fuel categories. Averages from this report were used only when fuel-use patterns were homogeneous within a major fuel category. The unit-specific listings were used to develop quantity-weighted averages when differentiation was required (e.g., between bituminous and subbituminous coal prices).

Fossil fuel prices were average prices for each power pool rather than actual unit-by-unit prices. Averaging prices reduced data coding requirements and eliminated some of the unit-specific sensitivities to variations in monthly fuel prices. An examination of several consecutive monthly reports showed that the average fuel prices tended to be quite stable, while unit-specific costs often varied significantly due to factors such as contract expirations, escalation clauses, and spot market conditions. In lieu of extensive fuel pricing studies of specific units, power pool averages eliminate some of the biases that would be introduced throughout the study period for unit cost rankings and associated loading levels.

Nuclear fuel costs were based on 1982 plant-specific data from FERC Form 1.[19] Gross National Product (GNP) price deflators were used to estimate the costs in 1984 dollars.[23] As with heat rate estimates, there are inherent uncertainties in assigning fuel costs based on a single year of recorded data. However, nuclear fuel costs do vary significantly because of many unit-specific factors such as contract arrangements for uranium supply, enrichment services, and transportation requirements. Although changes in the future (such as contract expirations) may cause unit-specific costs to change, the time frame of this analysis is sufficiently limited (fall 1984-summer 1986) that dramatic changes are not likely to occur. If replacement energy costs are estimated for the period beyond summer of 1986, a reevaluation of each unit's fuel cost would be warranted.

The same steps were taken to fill in missing data and characterize costs for planned facilities as were described for heat rate assignments. Additional steps were needed to estimate the fixed component of nuclear fuel costs so these costs could be properly accounted for in the shutdown studies. The fixed component is associated with fuel inventory carrying charges and is not avoided in short-term shutdowns.

According to EPRI estimates for 1985, the fixed component represents 20% of the total fuel costs.[17] The actual 1982 fuel costs for each plant were normalized for a 57% capacity factor, corresponding to the nominal factor used in the simulations. Only the variable fuel component, representing 80% of the total costs, was assumed to be avoided in the shutdown cases.

Variable operation and maintenance (O&M) costs, except those for nuclear units, were determined from *EPRI Regional Systems.*[18] Again, GNP price deflators were used to adjust the costs to 1984 dollars.[23] Zero real escalation rates were assumed for nonnuclear O&M costs.

For coal units, variable O&M costs are differentiated according to coal type, emission control option, and region. Costs range from 1.2-5.0 mills/kWh, with the lowest costs occurring for high-sulfur coal units without flue-gas desulfurization (FGD) equipment. The highest variable O&M costs are assigned to high-sulfur units with FGD systems. Low-sulfur coal units are assigned costs of 1.7-2.7 mills/kWh, with the higher costs being associated with FGD systems. Regional variations within these ranges reflect relative differences in average coal quality between regions.

Variable O&M costs for oil- and gas-steam units were uniformly set at 2.1 mills/kWh, combustion turbines were assigned 3.8 mills/kWh, and diesel units were assigned 8.9 mills/kWh. Although the cost for diesels is relatively high, these units typically generate a small portion of total demand and a small fraction of replacement energy. Therefore, the contribution from these units to total dollar costs is typically small.

As explained previously, fixed costs do not contribute to the replacement energy costs for short-term shutdowns. However, for reference, the fixed O&M costs* for coal units range from $5.4-12.5/kW-yr for high-sulfur non-FGD units, $13.0-24.0/kW-yr for high-sulfur FGD units, $9.2-18.3/kW-yr for low-sulfur non-FGD units, and $14.2-23.0/kW-yr for low-sulfur FGD units. Unit size is the primary cause for variation within these categories. Fixed O&M costs for oil and gas units were set at $1.8-3.2/kW-yr, combustion turbines were assigned $0.4/kW-yr, and diesels were assigned $8.3/kW-yr.

Nuclear O&M costs were derived from DOE's *Update* and were applied uniformly to all nuclear units in the shutdown study.[21] In contrast to other cost components, nuclear O&M costs have shown a high rate of real escalation in the recent past. After adjusting for inflation (using GNP price deflators), the average cost ranged from 3.8 mills/kWh in 1977 to 8.8 mills/kWh in 1982,** an average annual increase of 18%/yr. For any multiple-year period ending in 1982, the average annual escalation ranges between 16%/yr and 21%/yr. The value of 18%/yr, which occurred over the six-year period from 1977 to 1982, was selected as a representative estimate for real escalation of nuclear O&M costs.

As with fuel costs, nuclear O&M costs must be differentiated between fixed and variable components. Estimates for the percentage split differ widely; estimates for the variable component range from a low value of 0.2%[24] to a high value equal to the annual plant capacity factor[17] (i.e., 57% under assumed reactor characteristics). The Energy Information Administration estimates that fixed costs represent about 80% to 90% of total O&M costs.[25] For this study, a value of 80% was selected for fixed nuclear O&M

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*Fixed O&M costs are differentiated by unit size, in addition to the other distinctions made for variable O&M costs.

**Costs for 1982 were the most recent available from Ref. 21.

costs. The result for 1984 was total O&M costs of 12.3 mills/kWh, variable O&M costs of 2.5 mills/kWh, and fixed O&M costs of 9.8 mills/kW. With an annual capacity factor of 57%, the fixed component translates into $49.0/kW-yr.

Variable costs are assigned to emergency purchases, which are defined here as the portion of energy demand that cannot be satisfied by the power pool or firm purchases.* This portion of energy demand is assumed to be supplied from an interconnected system, at costs typically higher than those of firm purchases. In this study, the costs of emergency purchases are based on the average total variable costs (variable O&M and fuel costs) for combustion turbines and oil-steam units. The result is an average cost of 66 mills/kWh, which was applied uniformly to all of the power pools. Emergency purchases tend to represent a small component of total replacement energy costs because most replacement energy is supplied by units within the power pool under investigation.

Firm purchases and firm sales were assumed to be constant for each power pool, partly because the shutdowns being studied were short-term and partly because there were no supportive data showing the extent to which interpool exchanges and costs would change under alternative shutdown conditions. Purchases and sales are particularly difficult to treat consistently if shutdowns occur simultaneously in interconnected power pools, especially pools that would normally provide each other with economy exchanges. For short-term shutdowns and large pools of generating units, however, a reasonable approach is to fix the firm purchases at a constant value in each pair of simulations (one with the unit operational and another with the unit out of service). The effects of shutdowns on economy exchanges within a power pool are accounted for directly in the production-cost simulations. Emergency transfers are likely to be supplied by higher-cost units outside the pool; hence, oil-steam and combustion turbine costs are used as a basis for calculating costs of emergency purchases.

2.2.4 Energy Demands

This report specifies electricity demands for each power pool in terms of monthly peak loads, load duration curves, and load growth rates. These load characteristics were constructed primarily from data published in regional NERC reports.[1-9] The load data account for transmission losses as well as projected customer demands. Relative monthly peak loads (fractions of annual peak) and monthly load factors** were derived from monthly peak hour demands (reported in megawatts) and net energy (reported in gigawatt-hours) for each power pool for 1984. The monthly load factors

*Firm purchases are typically determined far in advance (i.e., a year or more) according to projected loads and generator availabilities. Economy purchases are arranged with shorter notice (i.e., days or hours) in response to relative costs among interconnected systems. Emergency purchases may be conducted with only a few minutes notice or less to avoid system failures or disruptions in service.

**The monthly load factor is defined as the monthly net energy divided by the product of monthly peak hour demand times the number of hours in the month (with appropriate conversion of gigawatt-hours to megawatt-hours if peak load is given in megawatts).

were used to select cumulative load duration curves* from EPRI-based data.[18] These selected load duration curves fit closely with total monthly and annual energy demands reported by the NERC regions.

The actual peak loads (expressed in megawatts) used in this study were based on projections for 1984 through 1986. The 1984 annual peak loads were identified from the monthly peaks projected for 1984. These values were preferred over summer and winter *annual* peaks because only the monthly peaks cover the full calendar year. Annual peak loads for 1985 and 1986 were derived by escalating the assumed 1984 peak according to the average annual growth rate over the 1984-1986 period. Monthly peaks for 1985 and 1986 thus have the same relative monthly load fractions as those for 1984. The annual load factor and normalized monthly profiles were assumed to remain unchanged over the study period, even while peak loads change. For short-term studies this assumption is reasonable. However, for longer-term studies, the trends in energy demands and potential load management policies must be considered for their possible impacts on annual and monthly load characteristics.

2.2.5 Energy Transfers Between Power Pools

Energy transfers between power pools can significantly affect replacement energy costs. However, the dynamic nature of power pool operations and interactions makes it difficult to predetermine the timing and magnitude of transfers. For many pools, economy energy exchanges are determined only days or hours in advance. Such exchanges occur in response to unit availabilities and load levels that are influenced by random factors such as unit failures and weather conditions. Emergency transfers may be implemented with even shorter notice. Firm capacity differs from economy and emergency exchanges in that contractual agreements for firm capacity may be reached far in advance of actual transfers.

The NERC has indicated that, in many regions, transmission constraints "limit the ability of utilities to take advantage of all the available economy energy."[26] Such constraints especially affect power pools with the greatest incentives to engage in transfers. Power pools that depend heavily on expensive oil- or gas-fired generation are most likely to seek purchases from lower-cost sources in neighboring power pools. In these areas, however, transmission lines "are being operated at or near their maximum reliable loading levels most of the time."[26] Thus if reactors in these areas are shut down, replacement energy is not likely to be served by additional economy purchases, but instead by higher-cost units within the affected power pool. In other areas, the price differential between potential purchases and internally generated replacement energy is not as significant, so the overall costs for replacement energy are not as sensitive to economy transfer assumptions.

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*Cumulative load duration curves portray the cumulative probabilities of load occurrences as a function of the possible load levels. These curves provide the basis for probabilistically combining generating unit availabilities with load variations.

Intrapool exchanges were modeled implicitly in the production-cost simulations. For most power pools considered in this study, however, external energy transfers were predefined on the basis of NERC estimates.[27] The NERC annual summary report tabulates net imports (total imports minus exports) projected through 1992, which represent, approximately, the firm contracts for energy exchanges. Economy and emergency transfers were handled indirectly for most power pools by assigning variable costs to the portion of demand that was not supplied by firm purchases, firm sales, and generation from the power pool.* As explained in Section 2.2.3, these costs reflect the fact that some of the remaining energy demand may be served by moderately high-priced generation while a significant portion may also require generation from the highest-cost sources, such as peaking units that require distillate oils.

Estimates for energy transfers were expanded for two U.S. regions in which exchanges differed significantly from the nominal exchanges reported by NERC. The modifications affected power pools in the Western Systems Coordinating Council (WSCC) and the Southeastern Electric Reliability Council (SERC). For WSCC, average transfers reported by NERC for the Northwest Power Pool and the California-Southern Nevada pool are based on adverse conditions for hydroelectric generation.[27] For 1984, NERC estimates that, under adverse conditions, hydroelectric generation in the Northwest will contribute 120×10^9 kWh to the net demand. Under median conditions, hydroelectric generation will contribute 145×10^9 kWh, with most of the additional generation being transferred to the California-Southern Nevada system.[28] Monthly patterns in hydroelectric capacity, generation, and energy transfers for median conditions were characterized in the shutdown simulations.

In the SERC region, the transfers from the Southern Companies Subregion to Florida are near maximum. The so-called "coal-by-wire" generation is being used to displace oil- and gas-fired generation in the Florida systems.[29] In 1984 the transfers are expected to be approximately 17×10^9 kWh. They are estimated to increase to 25×10^9 kWh in 1985 and then decline slightly to 24×10^9 kWh in 1986.

2.3 KEY MODELING ASSUMPTIONS

This section discusses several key modeling assumptions that significantly affect the interpretation and use of results. Topics include the representations of nuclear units, derivations of replacement energy costs, and identification of NERC regions and power pools.

*It was assumed that interties between power pools could supply all of these remaining energy demands. This assumption is reasonable for an evaluation of single-unit shutdowns, but would probably not hold under multiple-shutdown conditions (as addressed in Appendix B). Under those conditions some of the energy demand might not be satisfied.

2.3.1 Nuclear Unit Representations

Normal Reactors

In the simulations, nuclear capacity factors are determined on the basis of forced outage rates (FORs), maintenance requirements, and other loading restrictions. Typical loading restrictions include such factors as limited load-following capability, spinning reserve requirements, transmission constraints, and insufficient demands for full loading. As mentioned previously, the FOR for nuclear units was set at 21.7% and the annual maintenance requirement, including refueling, was assumed to be 76 days.* These two factors limit the maximum annual capacity factor to 62%. Allowances for additional loading restrictions as described above can reduce the annual capacity factor by as much as 8% to 57%.**

For reactors scheduled to begin service during one of the study years, the apparent annual or seasonal capacity factors could be quite small, even though the generation may be near maximum for the time the reactor is in service. In this report nuclear capacity factors were adjusted to reflect the percentage of time that a unit is in service. Thus, if a unit operates at a 60% capacity factor for half of a season, the seasonal capacity factor is shown as 60% rather than 30%, so that capacity factor indicates the reactor's performance while in service. The results indicate which units are scheduled to begin service part way through a season.

Reactor under Investigation

To treat replacement energy costs uniformly from one season to the next, periods of planned maintenance were adjusted for the designated reactor. These adjustments were necessary to determine shutdown costs that would occur if the reactor was not scheduled out of service. Without these adjustments, replacement energy costs, measured in dollars, would be very low for the particular season in which maintenance was assumed to occur. Although dollar costs should be low if the shutdown overlaps a regular refueling and maintenance period, maintenance schedules are too uncertain to limit the results to unit-specific maintenance assumptions through the year 1986. Unadjusted results would preclude an examination of full shutdown costs if an overlap did not occur.

Examples in Sec. 3 show how the results can be adjusted for alternative maintenance assumptions. Maintenance for the entire system is initially scheduled to maximize the minimum expected reserve margin in the 24 periods of a given year. This schedule provides a reasonable distribution of maintenance for the system as a whole and yields identical schedules for each case study in a given power pool.

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*Routine maintenance and refueling outages are not scheduled for new units until their second year of operation.

**Under certain circumstances, nuclear capacity factors may be even lower if the total nuclear capacity that is not on scheduled maintenance in a particular study period exceeds minimum loads.

Adjusting results during maintenance periods for the units under investigation causes annual capacity factors for these units to appear higher than the typical value of 57% for other nuclear units. Without scheduled maintenance the maximum seasonal capacity factors ranged between 72% and 78%. Simulated capacity factors were frequently near the lower end of this range. In this report, seasonal results cannot be directly summed to arrive at annual replacement energy costs or annual capacity factors. The results are oriented toward short-term costs and would be based on different assumptions if the study focused on long-term shutdowns. Still, examples in Sec. 3 show how to approximate annual costs under alternative maintenance assumptions.

2.3.2 Derivation of Replacement Energy Costs

Two simulations are compared for each reactor; both cover the two-year study period from fall 1984 through summer 1986. In one case the designated reactor is in service, except for planned and forced outages, for the entire simulation time, or for some fractional period if it is expected to become operational within the two-year period. In the other case, the designated unit is treated as unavailable for the entire study period.

Each year is subdivided into 24 periods of equal length. Results for each period are compared to determine changes in total production costs. Period results are then grouped by season. Variable fuel and O&M costs are the primary components of replacement energy costs. Fixed costs remain the same whether the designated unit is operating or shut down. These costs include fixed O&M and fixed fuel costs for the reactor under investigation, because such costs are still incurred during short-term shutdowns.

For periods in which a reactor was initially assumed to be scheduled for planned maintenance, replacement energy costs were derived from simulations for other units not originally scheduled for maintenance in those periods. Costs and capacity factors were selected from those of another unit, most similar in size to the one requiring adjustment. These costs were then corrected for heat rate and variable fuel cost. The results were added to the results for other periods in a given season that the unit was in service.

This approach provided the most reasonable method of handling maintenance effects consistently, both for comparisons between seasonal results for a single unit and for comparisons of results for several units in the same power pool. The maintenance schedule is kept the same for all case studies in each pool, so inconsistencies tend to be minimized or eliminated. Intraseasonal cost differentials are recognized and integrated into the shutdown costs for each reactor. These differentials can create counterintuitive results unless the same maintenance schedules are used for all simulations in a given power pool.

In five cases where reactors are jointly owned by utilities in more than one power pool, the simulations were performed separately for the portions of capacity in each pool. The final costs of replacement energy were determined by summing the total dollar costs and total generation, and then calculating the average costs per kilowatt-hour and dollars per service-day.

2.3.3 Identification of NERC Regions and Power Pools

Figure 2.1 illustrates the approximate geographical boundaries of the nine NERC regions.* Members and associate members of these regions include virtually all of the generating capability in the United States. Reports from each of these regions provide a major resource for verifying inventories of generating units and load characteristics.[1-9] Summary reports from the national headquarters of NERC provide data on energy transfers, unit availabilities, and coal conversions.[16,27,30]

Power pool compositions are described in Table 2.1 and are shown graphically in Fig. 2.2. The groupings of utilities into power pool areas, which constitute subregions of NERC regions, were assigned according to references from the Federal Energy Regulatory Commission,[31-36] DOE,[37] and NERC.[1-9,27] The primary goal in designating power pools was to aggregate the utilities that have highly coordinated unit dispatch or energy exchanges. The objective in this study is to examine shutdown costs in the context of pooled generating systems; systems within a pool are likely to respond first to other systems in the pool that experience short-term shutdowns. To satisfy this objective, the pool designations were based on broader definitions than the formal power pool agreements, which include "tight" and "loose" pools as defined by the Federal Energy Regulatory Commission.[31] Tight pools are centrally dispatched and include penalties for failing to meet reserve requirements. Loose pools are coordinated but have no central dispatch or penalties for failing to meet reserve requirements. The power pools defined in Table 2.1 go one step further in grouping utilities that may lack formal coordination agreements but are likely to achieve significant operating economies through energy exchanges.

A total of 33 power pools were designated for this study. Twenty-one of the power pools contain the 108 nuclear reactors that were examined. Two of these 21 pools were initially subdivided into two separate pools each. These included the ERCOT NERC region (pools 5 and 6), and the Illinois-Missouri subregion of MAIN (pools 9 and 10). The four pools were originally defined separately because they are sometimes described individually as formal power pools or systems with strongly coordinated operations. However, they were regrouped to form two pools because of the interties and coordination between each of the two pairs. Table 2.1 indicates which power pools included reactors that were examined in this study.

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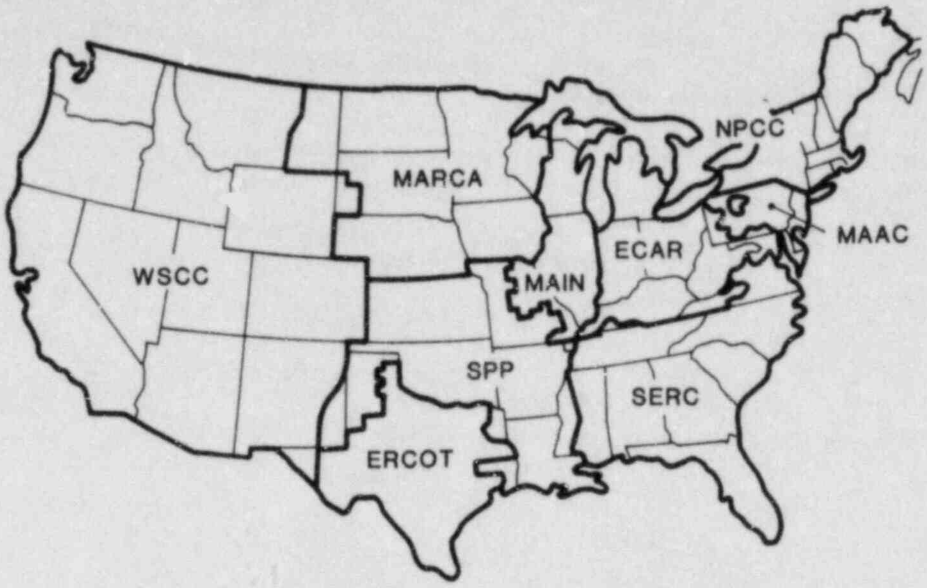
*Only the U.S. portions of Western Systems Coordinating Council, Mid-Continent Area Power Pool, and Northeast Power Coordinating Council are shown. With the exception of net energy sales to the United States, Canadian portions of these regions were not included in this study of short-term reactor shutdowns.



ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interpool Network

MARCA
Mid-Continent Area Reliability Coordination Agreement

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southeast Power Pool

WSCC
Western Systems Coordinating Council

FIGURE 2.1 NERC Regions

FIGURE 2.2 Power Pools: Approximate Geographical Boundaries (see Table 2.1 for definitions)

TABLE 2.1 Power Pool Compositions

Power Pool Number	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
20[a]	SPP	Group A (W. Arkansas-Louisiana-Mississippi area of SERC)
21	SPP	Group B (Oklahoma area of SERC)

TABLE 2.1 (Cont'd)

Power Pool Number	NERC Region	Power Pool Composition
22[a]	SPP	Group C (W. Missouri-Kansas area of SERC)
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[a]	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.

3 POWER POOL DESCRIPTIONS AND INTERPRETATION OF RESULTS

This section summarizes the characteristics of each of the 21 power pools in which a nuclear reactor is expected to be operating by the summer of 1986. This summary is followed by a discussion of important assumptions for the replacement energy cost estimates and some sample calculations illustrating how to interpret the results given in Sec. 4.

3.1 POWER POOL CHARACTERISTICS

As described in Sec. 2, the power pool groupings were selected as a basis for the estimates of replacement energy costs. The power pools represent a diverse set of electricity suppliers, which differ in the following important characteristics that affect replacement energy cost:

1. Total system capacity,
2. Annual peak load,
3. Annual energy demand,
4. Annual load factor,
5. Prices for all fuels,
6. Mix of existing capacity by fuel type, and
7. Mix of generation by fuel type.

The difference between the system capacity (1) and peak load (2) indicates the reserve available at the time of the peak load if no scheduled maintenance or forced outages occur at that time. If the capacity of the reactor is a significant fraction of the reserve capacity, the pool may have problems with generation system reliability and attendant cost penalties. Given that reserve margins are now relatively high throughout the electric utility industry, reliability problems are not expected to be an important element of cost in the near term. However, multiple shutdowns of nuclear units could cause reliability problems and incremental costs. These considerations are discussed in App. B.

The annual energy demand (3) and annual load factor (4)* indicate the variability of loads throughout the year. An annual load factor of approximately 65% or greater implies relatively steady loads, while a load factor below 55% implies significant

*Annual load factor is defined as (annual energy demand) ÷ (peak load x 8760), where 8760 is the number of hours per year.

seasonal variability. Such characteristics strongly influence the maintenance scheduling and availability of relatively inexpensive replacement energy at various times of the year.

Fuel prices (5) are an important factor in determining replacement energy cost. Coal, oil, and gas prices vary considerably by region, as indicated in Sec. 2. Reasons for this variability include transportation costs, fuel availability, regulations, and existing contracts.

The mixes of generating capacity (6) and generation (7) give a rough impression of whether the replacement energy cost for a reactor will be high. Power pools dominated by coal and nuclear generation would probably have relatively low replacement energy costs, while power pools dominated by oil and gas generation would probably have relatively high replacement energy costs.

The seven power pool characteristics described above are displayed in the figures and tables that follow. Tables 3.1 and 3.2 define the descriptors used in Figs. 3.1-3.42, which depict the capacity and generation mix of each power pool that contains at least one nuclear reactor. Tables 3.3-3.23 list the capacity, peak load, energy demand, load factor, and fuel prices for each power pool that contains at least one nuclear reactor. The information on the power pools is presented in numerical order. Table 2.1, on pages 25-26, lists the utilities or constituents of each power pool, and the power pools can be geographically identified by referring to Fig. 2.2, on page 24.

All load and generation data reported in this section account for transmission losses in addition to customer demands. The power pool characterizations differ with regard to their format, depending on whether net purchases or sales are represented. For power pools with net purchases, the full system energy demand is shown in the composition table, and the energy of firm purchases is shown in the corresponding illustration of generation mix. Sales are treated as additions to the demand to be met by generation within the system. Therefore, power pools with net sales have the system demand shown in the table, and an additional entry to show total generation including sales. However, a corresponding entry is not included in the generation-mix illustration because the energy for sales is supplied from a mix of fuel types in the system.

The mixes of fuel types, specifically those required for sales, were not isolated from other fuel use when replacement energy costs were determined. Also, the capacity illustrations do not include purchases or sales, so the relative mix of generating capability within each power pool can be displayed. Fuel types that contributed less than 0.1% to the pool totals were included in the capacity illustrations but not in the generation illustrations.

These power pool characteristics provide initial insights into the level of replacement energy costs expected for any reactor. Section 3.2 reviews the assumptions and mechanics of the actual calculations so report users can interpret the results in Sec. 4.

TABLE 3.1 Descriptors Used in the Capacity Figures

Descriptor	Unit Type	Fuel Type
Coal	Steam turbine	Bituminous and sub-bituminous coal, lignite and anthracite
Gas	Steam turbine	Natural gas
Geothermal	Condensing turbine	Geothermal steam
Hydroelectric	Conventional hydroelectric turbine	Water
Nuclear	Steam turbine	Nuclear fuels
Oil-steam	Steam turbine	Residual oil
Other	Steam turbine	Refuse or wood
Peaking gas	Diesel or combustion turbine	Natural gas
Peaking oil	Diesel or combustion turbine	Distillate oil
Pumped storage	Pumped storage hydroelectic turbine	Various

TABLE 3.2 Descriptors Used in the Generation Figures

Descriptor	Unit Type	Fuel Type
Coal	Steam turbine	Bituminous and sub-bituminous coal, lignite and anthracite
Firm purchases and sales	Various	Various
Gas	Steam, diesel, or combustion turbine	Natural gas
Geothermal	Condensing turbine	Geothermal steam
Hydroelectric	Conventional hydroelectric turbine	Water
Nuclear	Steam turbine	Nuclear fuels
Oil	Steam, diesel, or combustion turbine	Residual or distillate oil
Other	Steam turbine	Refuse or wood
Pumped storage	Pumped storage hydroelectric turbine	Various

TABLE 3.3 Composition of Power Pool 1

Characteristic	Year 1984	1985	1986
Total system capacity (end-of-yr MW)	26,306	26,306	27,606
Annual peak load (MW)	16,193	16,792	17,413
Annual energy demand (10^9 kWh)	95	99	102
Total generation including sales (10^9 kWh)	97	99	102
Annual load factor (%)	67	67	67
Fuel prices (¢/10^6 Btu)			
Nuclear fuel (unit-dependent; excludes fixed carrying charges)	42	42	42
Coal (bituminous, lignite)	180	180	180
Coal (subbituminous, anthracite)	not used	not used	not used
Distillate oil	614	614	614
Residual oil	not used	not used	not used
Gas	not used	not used	not used

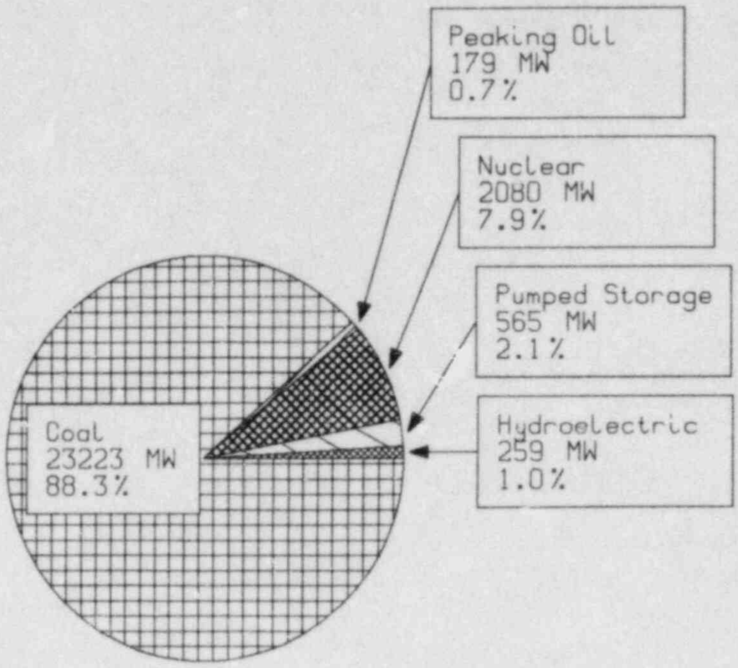


FIGURE 3.1 Expected Capacity in Power Pool 1 at the End of 1984

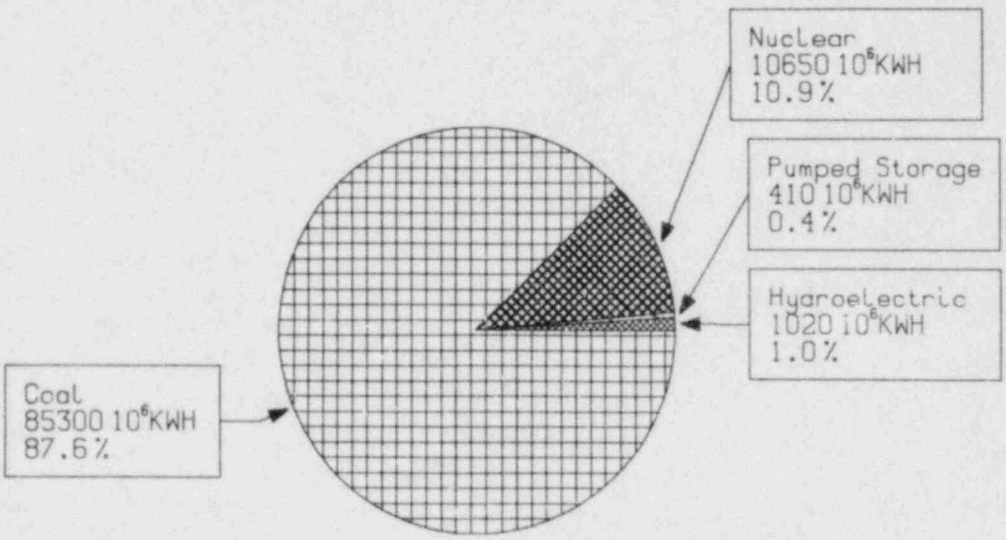


FIGURE 3.2 Nominal Generation in Power Pool 1 in 1984

TABLE 3.4 Composition of Power Pool 2

Characteristic	Year 1984	1985	1986
Total system capacity (end-of-yr MW)	14,854	16,065	16,898
Annual peak load (MW)	11,427	11,724	12,029
Annual energy demand (10^9 kWh)	65	66	68
Annual load factor (%)	65	65	65
Fuel prices (¢/10^6 Btu)			
Nuclear fuel (unit-dependent; excludes fixed carrying charges)	26-39	26-39	26-39
Coal (bituminous, lignite)	165	165	165
Coal (subbituminous, anthracite)	not used	not used	not used
Distillate oil	645	645	645
Residual oil	432	432	432
Gas	not used	not used	not used

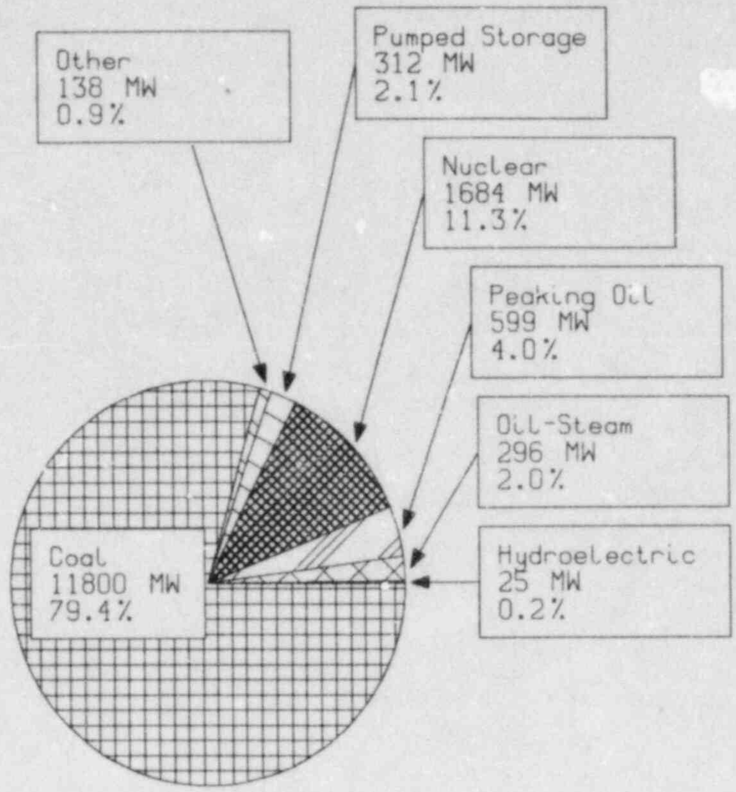


FIGURE 3.3 Expected Capacity in Power Pool 2 at the End of 1984

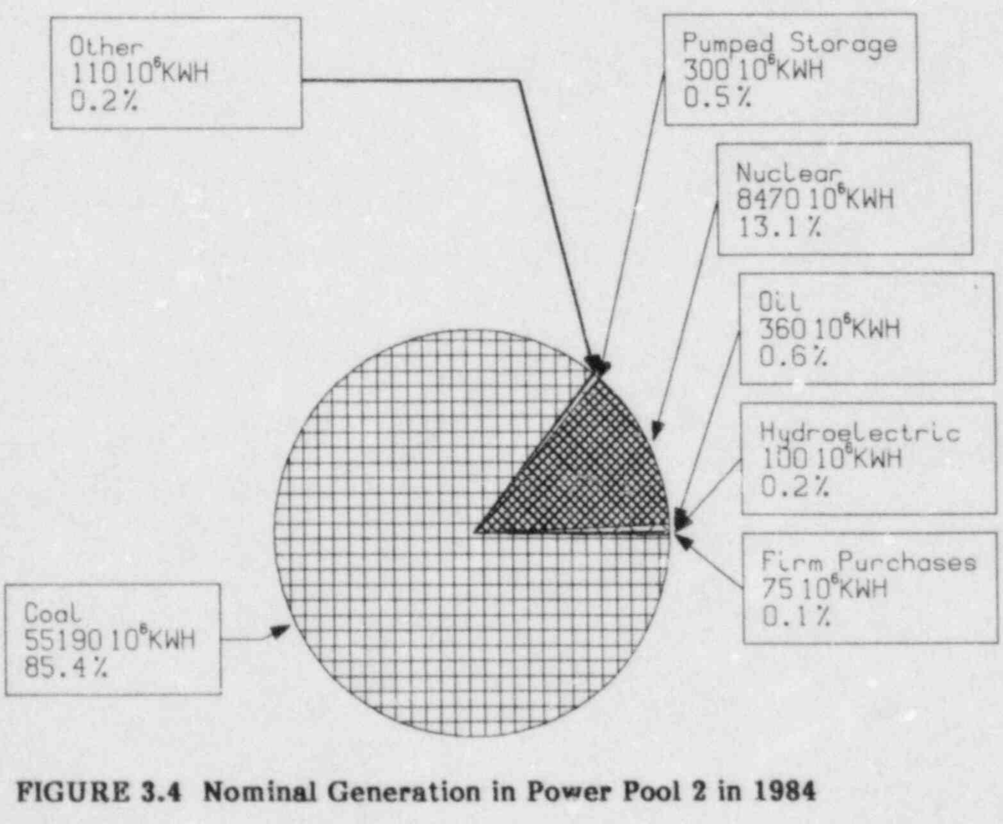


FIGURE 3.4 Nominal Generation in Power Pool 2 in 1984

TABLE 3.5 Composition of Power Pool 4

Characteristic	Year 1984	1985	1986
Total system capacity (end-of-yr MW)	17,928	18,603	19,421
Annual peak load (MW)	12,416	12,863	13,326
Annual energy demand (10^9 kWh)	69	72	74
Total generation including sales (10^9 kWh)	74	76	79
Annual load factor (%)	64	64	64
Fuel prices (¢/10^6 Btu)			
Nuclear fuel (unit-dependent; excludes fixed carrying charges)	38-55	38-55	38-55
Coal (bituminous, lignite)	195	195	195
Coal (subbituminous, anthracite)	193	193	193
Distillate oil	600	600	600
Residual oil	428	428	428
Gas	564	564	564

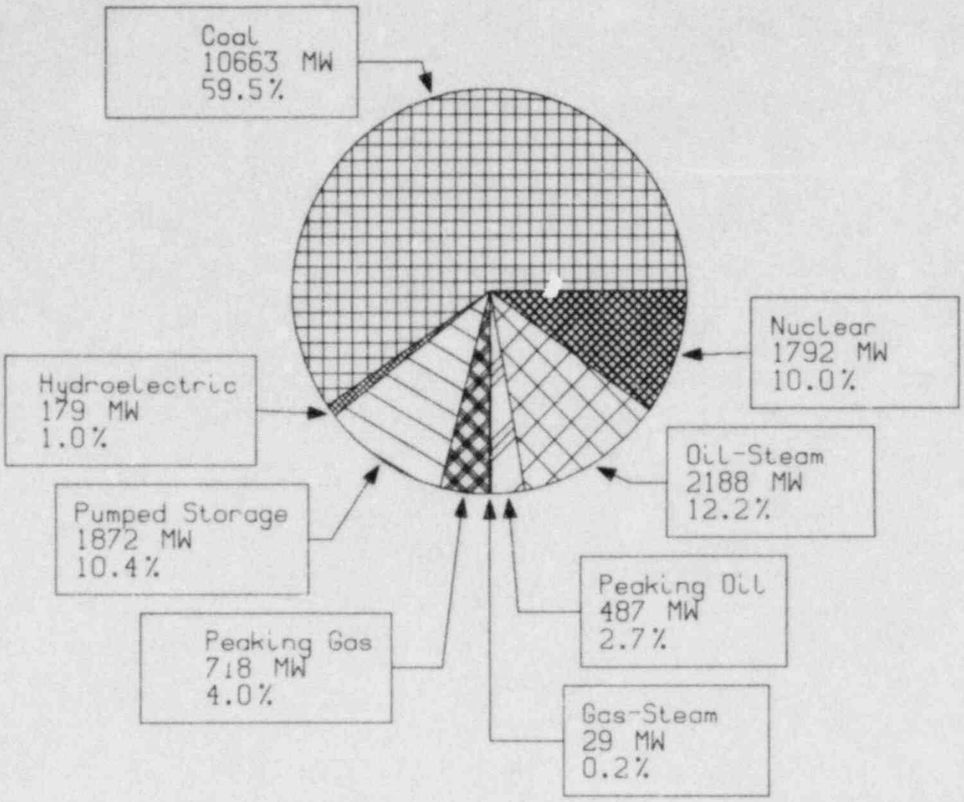


FIGURE 3.5 Expected Capacity in Power Pool 4 at the End of 1984

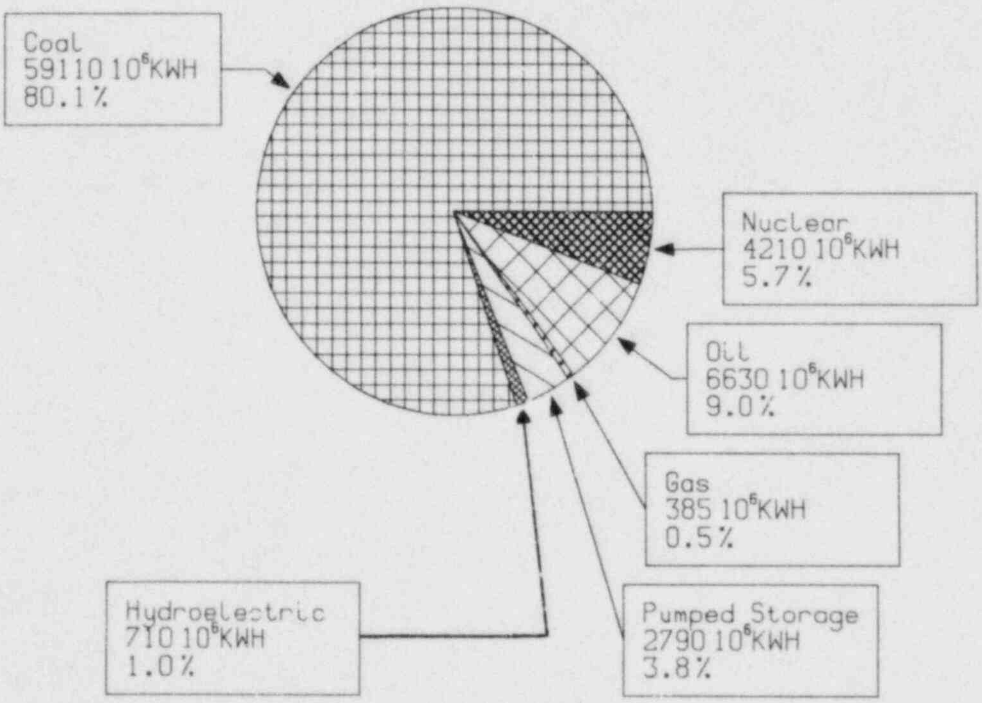


FIGURE 3.6 Nominal Generation in Power Pool 4 in 1984

TABLE 3.6 Composition of Power Pool 5-6[a]

Characteristic	Year 1984	Year 1985	Year 1986
Total system capacity (end-of-yr MW)	44,294	45,483	47,818
Annual peak load (MW)	36,802	38,016	39,271
Annual energy demand (10^9 kWh)	185	191	198
Annual load factor (%)	57	57	57
Fuel prices (¢/10^6 Btu)			
Nuclear fuel (unit-dependent; excludes fixed carrying charges)	50	50	50
Coal (bituminous, lignite)	92	92	92
Coal (subbituminous, anthracite)	270	270	270
Distillate oil	621	621	621
Residual oil	not used	not used	not used
Gas	355	396	396

[a]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.

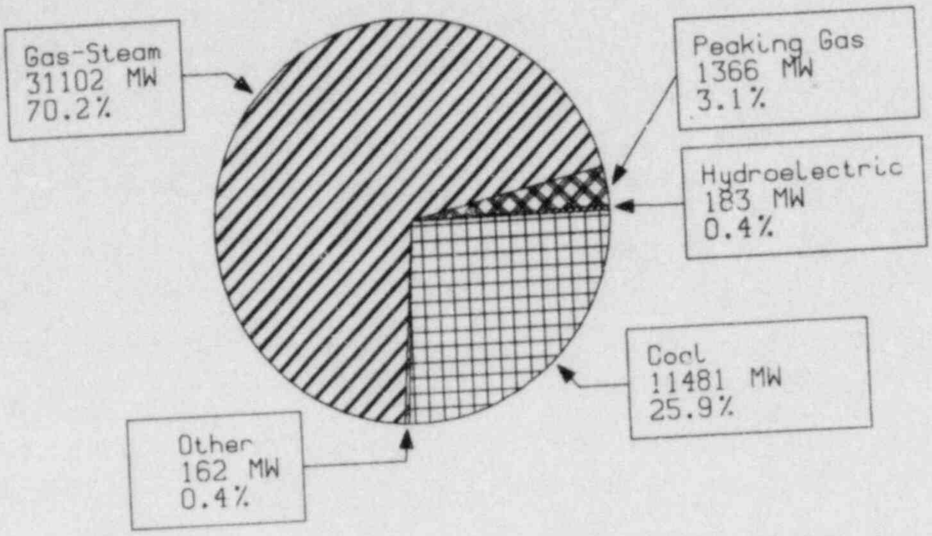


FIGURE 3.7 Expected Capacity in Power Pool 5-6 at the End of 1984

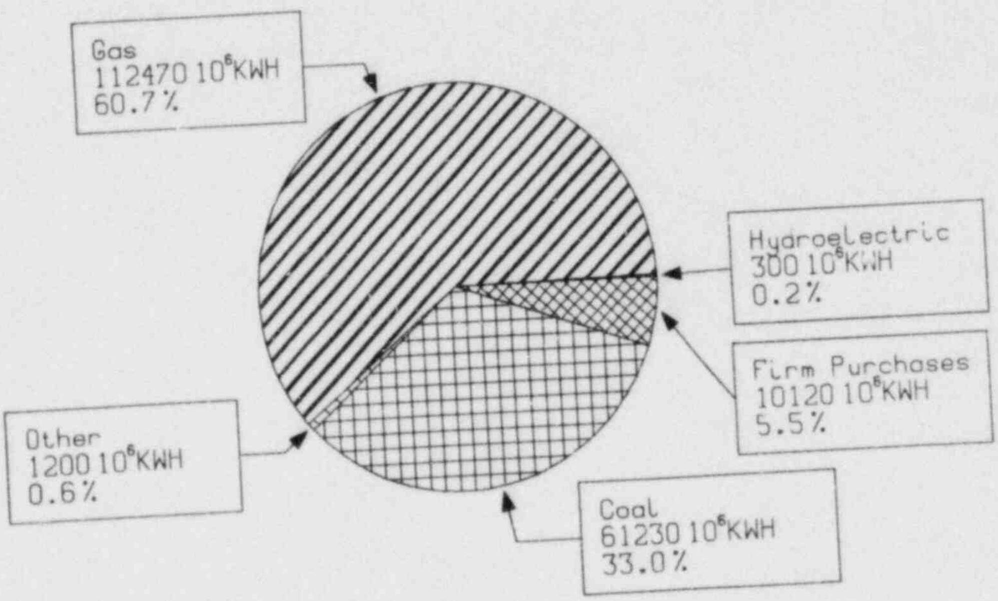


FIGURE 3.8 Nominal Generation in Power Pool 5-6 in 1984

TABLE 3.7 Composition of Power Pool 7

Characteristic	Year 1984	1985	1986
Total system capacity (end-of-yr MW)	47,049	49,033	50,140
Annual peak load (MW)	34,720	35,380	36,052
Annual energy demand (10^9 kWh)	179	183	186
Annual load factor (%)	59	59	59
Fuel prices (¢/10^6 Btu)			
Nuclear fuel (unit-dependent; excludes fixed carrying charges)	27-64	27-64	27-64
Coal (bituminous, lignite)	157	157	157
Coal (subbituminous, anthracite)	138	138	138
Distillate oil	609	609	609
Residual oil	481	481	481
Gas	405	433	433

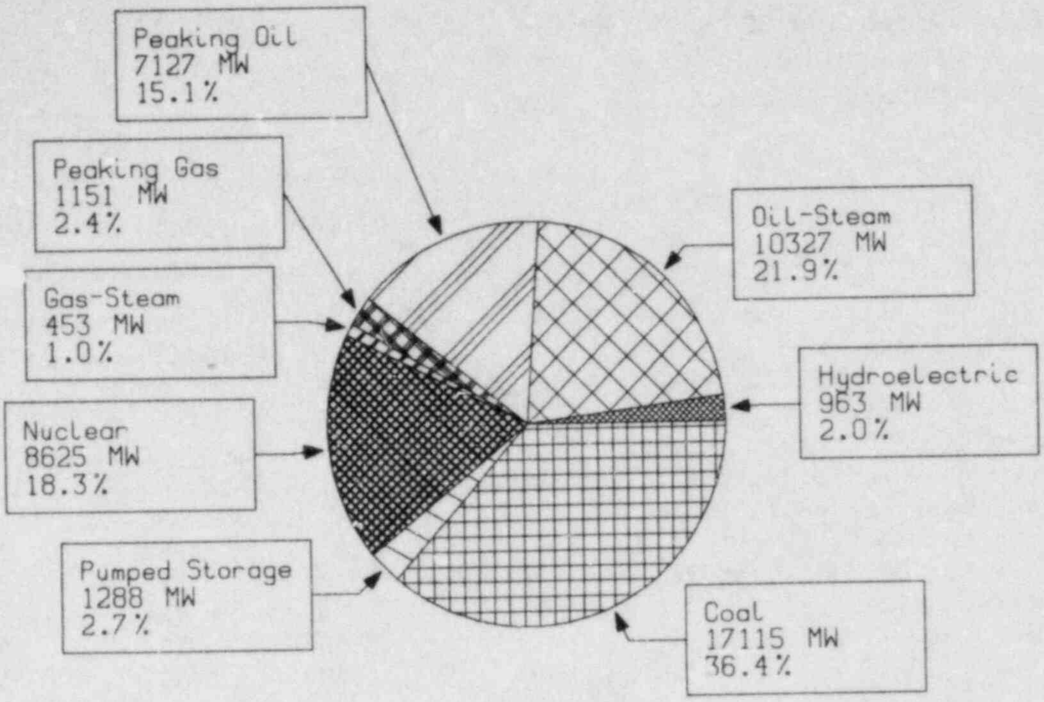


FIGURE 3.9 Expected Capacity in Power Pool 7 at the End of 1984

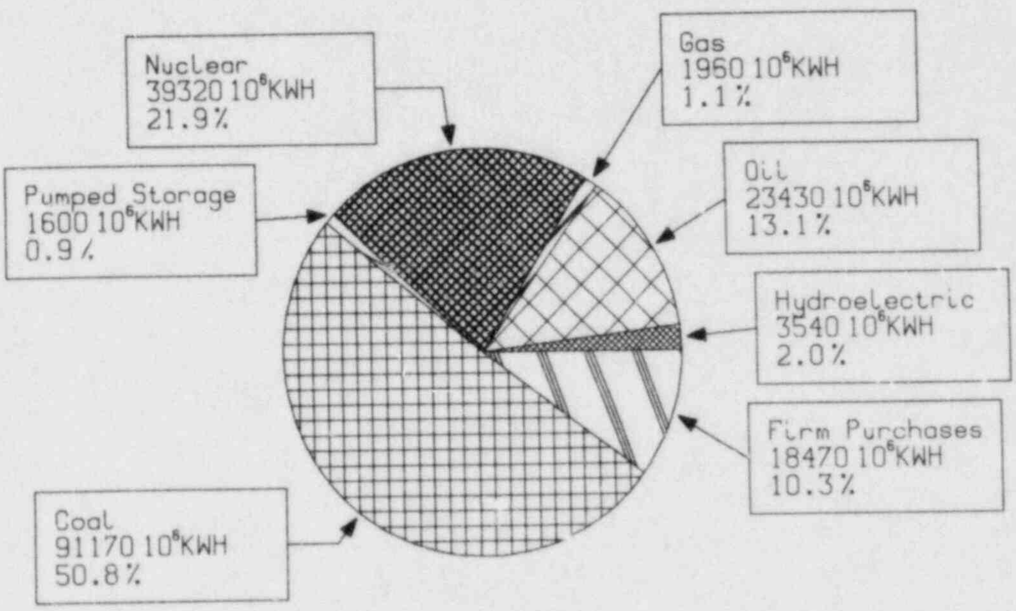


FIGURE 3.10 Nominal Generation in Power Pool 7 in 1984

TABLE 3.8 Composition of Power Pool 8

Characteristic	Year 1984	1985	1986
Total system capacity (end-of-yr MW)	17,739	18,862	21,102
Annual peak load (MW)	14,250	14,820	15,413
Annual energy demand (10^9 kWh)	66	68	71
Annual load factor (%)	53	53	53
Fuel prices (¢/10^6 Btu)			
Nuclear fuel (unit-dependent; excludes fixed carrying charges)	21-45	21-45	21-45
Coal (bituminous, lignite)	183	183	183
Coal (subbituminous, anthracite)	316	316	316
Distillate oil	624	624	624
Residual oil	553	553	553
Gas	529	529	529

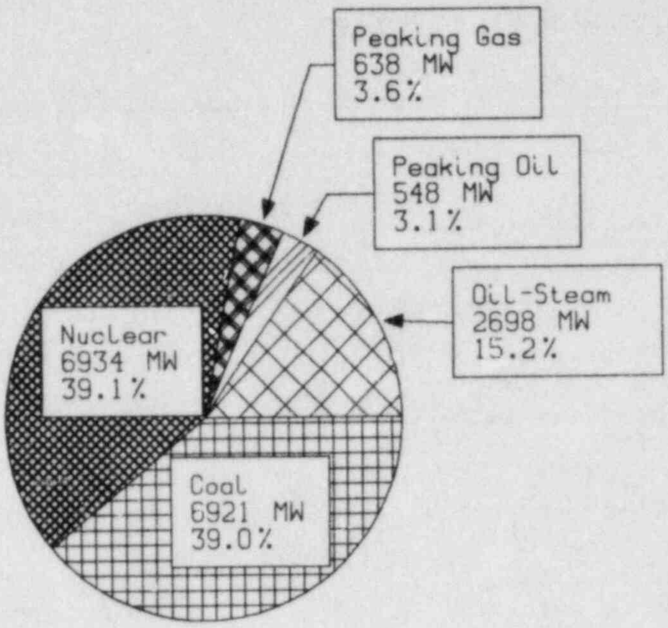


FIGURE 3.11 Expected Capacity in Power Pool 8 at the End of 1984

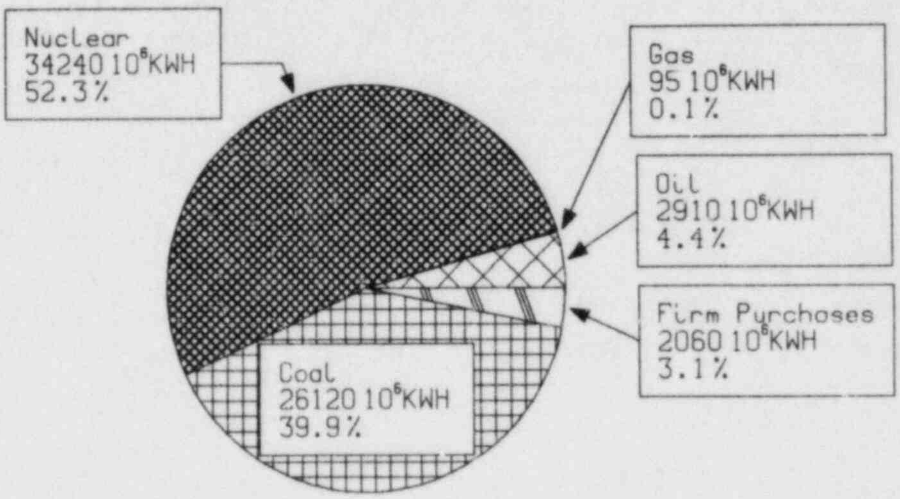


FIGURE 3.12 Nominal Generation in Power Pool 8 in 1984

TABLE 3.9 Composition of Power Pool 9-10[a]

Characteristic	1984	1985	1986
	Year		
Total system capacity (end-of-yr MW)	15,890	17,078	18,011
Annual peak load (MW)	12,747	13,015	13,288
Annual energy demand (10^9 kWh)	59	61	62
Total generation including sales (10^9 kWh)	61	64	66
Annual load factor (%)	53	53	53
Fuel prices (¢/10^6 Btu)			
Nuclear fuel (unit-dependent; excludes fixed carrying charges)	40	40	40
Coal (bituminous, lignite)	155	155	155
Coal (subbituminous, anthracite)	not used	not used	not used
Distillate oil	604	604	604
Residual oil	445	445	445
Gas	499	499	499

[a]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.

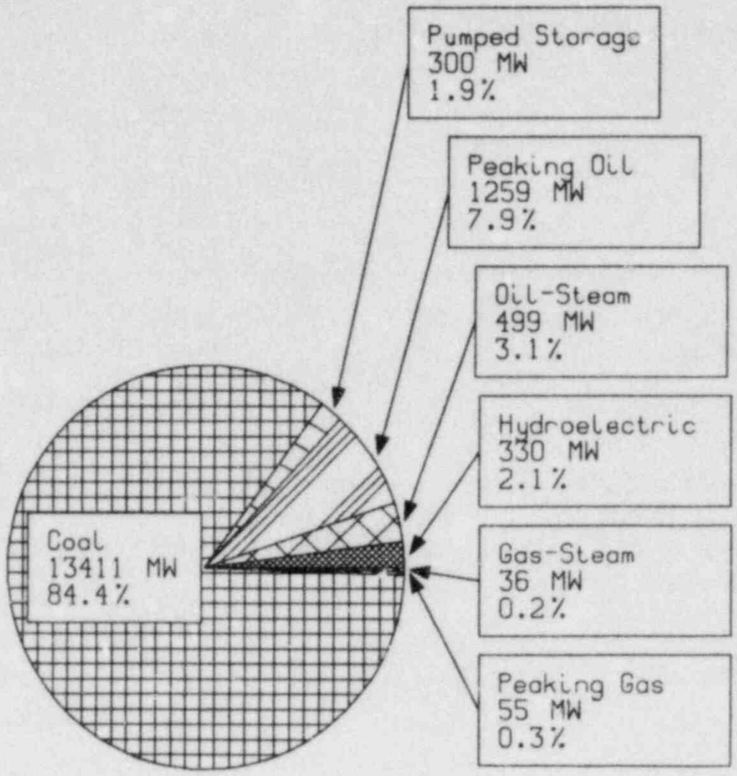


FIGURE 3.13 Expected Capacity in Power Pool 9-10 at the End of 1984

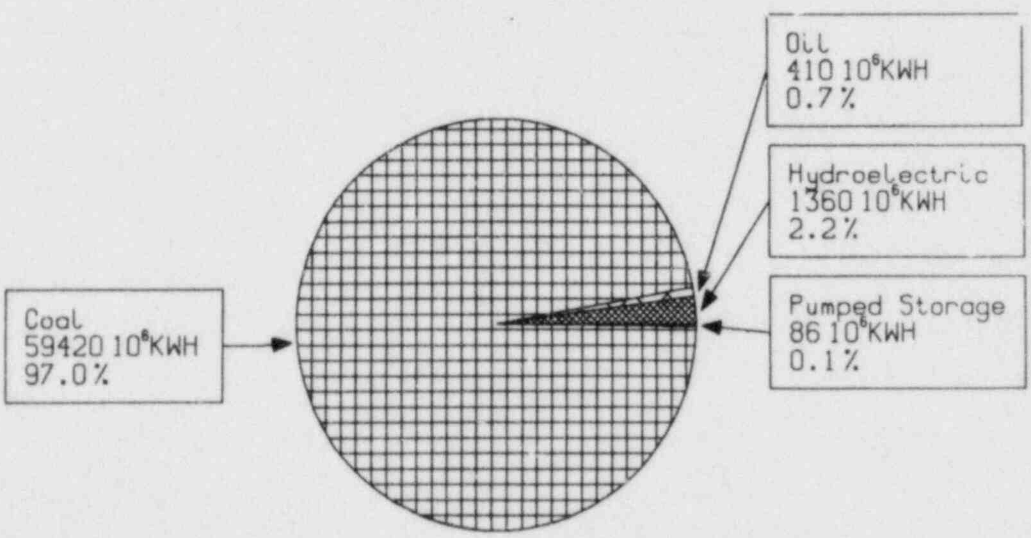


FIGURE 3.14 Nominal Generation in Power Pool 9-10 in 1984

TABLE 3.10 Composition of Power Pool 11

Characteristic	Year 1984	1985	1986
Total system capacity (end-of-yr MW)	9584	9972	9972
Annual peak load (MW)	6977	7158	7345
Annual energy demand (10^9 kWh)	40	41	42
Annual load factor (%)	65	65	65
Fuel prices (¢/10^6 Btu)			
Nuclear fuel (unit-dependent; excludes fixed carrying charges)	61-88	61-88	61-88
Coal (bituminous, lignite)	175	175	175
Coal (subbituminous, anthracite)	177	177	177
Distillate oil	625	625	625
Residual oil	not used	not used	not used
Gas	416	416	416

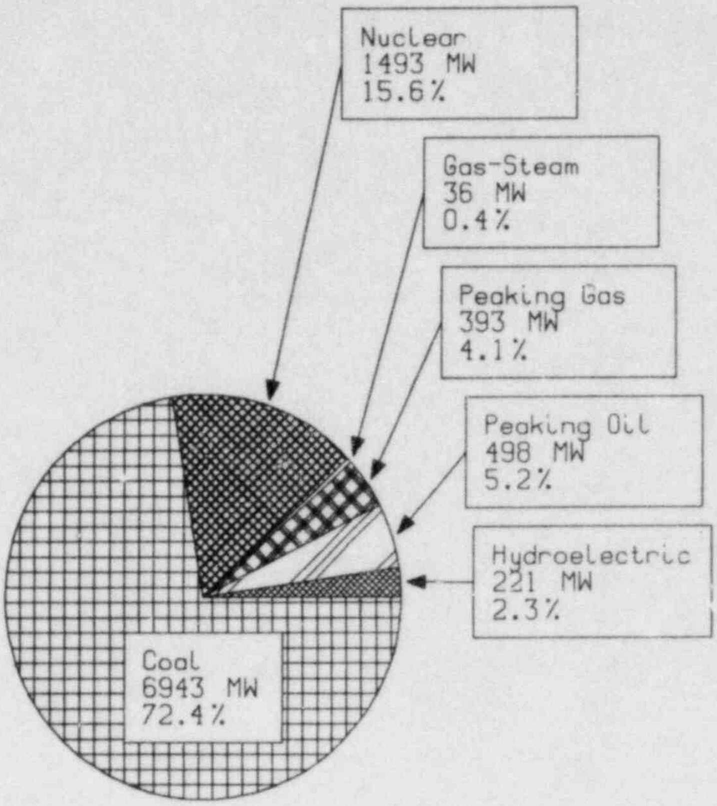


FIGURE 3.15 Expected Capacity in Power Pool 11 at the End of 1984

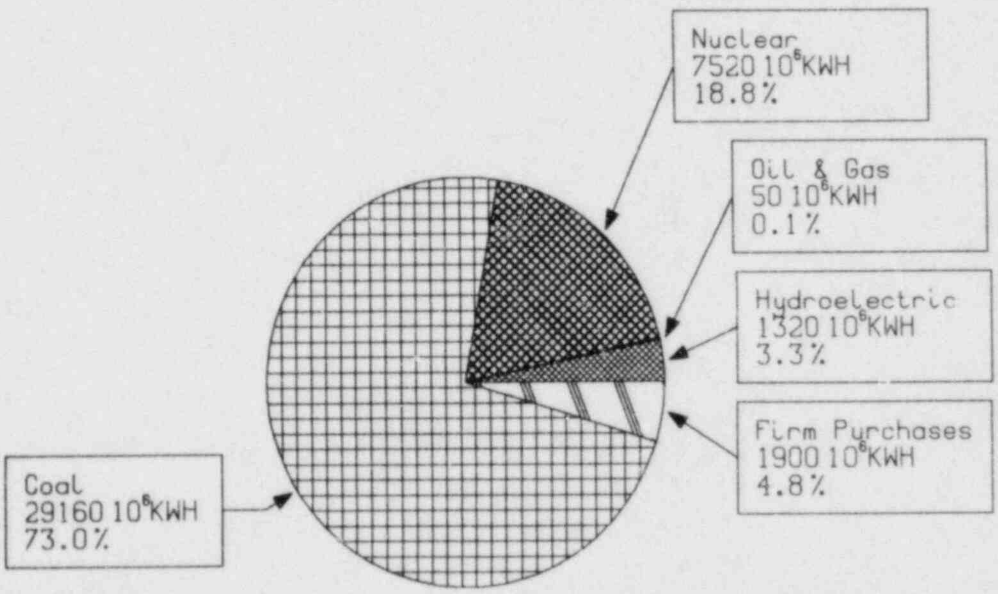


FIGURE 3.16 Nominal Generation in Power Pool 11 in 1984

TABLE 3.11 Composition of Power Pool 12

Characteristic	Year 1984	Year 1985	Year 1986
Total system capacity (end-of-yr MW)	30,661	30,692	31,173
Annual peak load (MW)	21,176	21,917	22,684
Annual energy demand (10^9 kWh)	105	108	112
Total generation including sales (10^9 kWh)	109	114	118
Annual load factor (%)	56	56	56
Fuel prices (¢/10^6 Btu)			
Nuclear fuel (unit-dependent; excludes fixed carrying charges)	35-61	35-61	35-61
Coal (bituminous, lignite)	96	96	96
Coal (subbituminous, anthracite)	122	122	122
Distillate oil	626	626	626
Residual oil	542	542	542
Gas	372	488	488

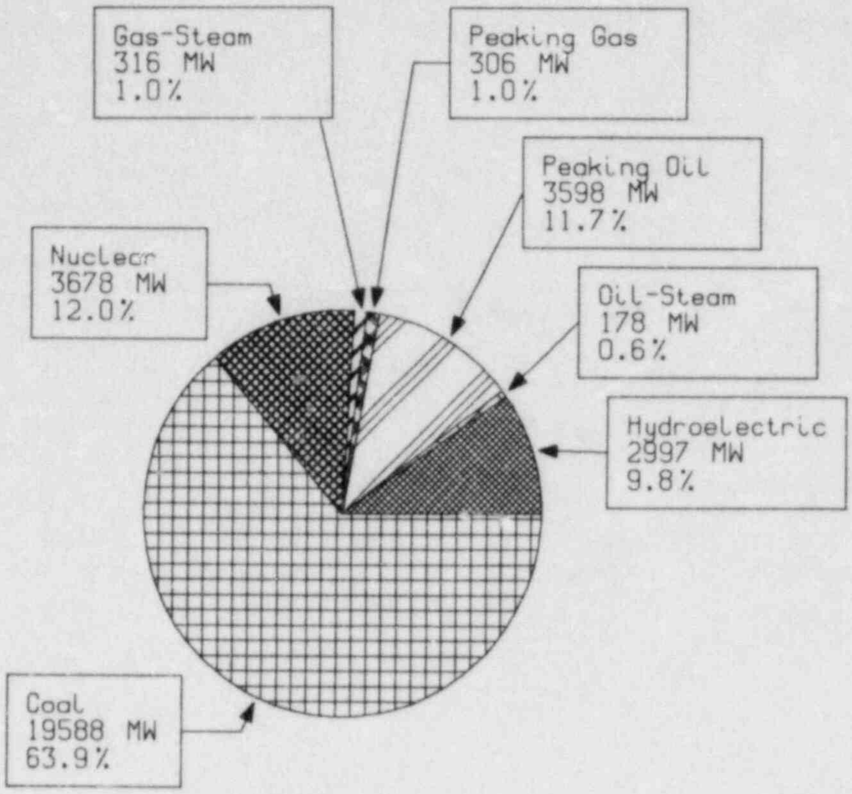


FIGURE 3.17 Expected Capacity in Power Pool 12 at the End of 1984

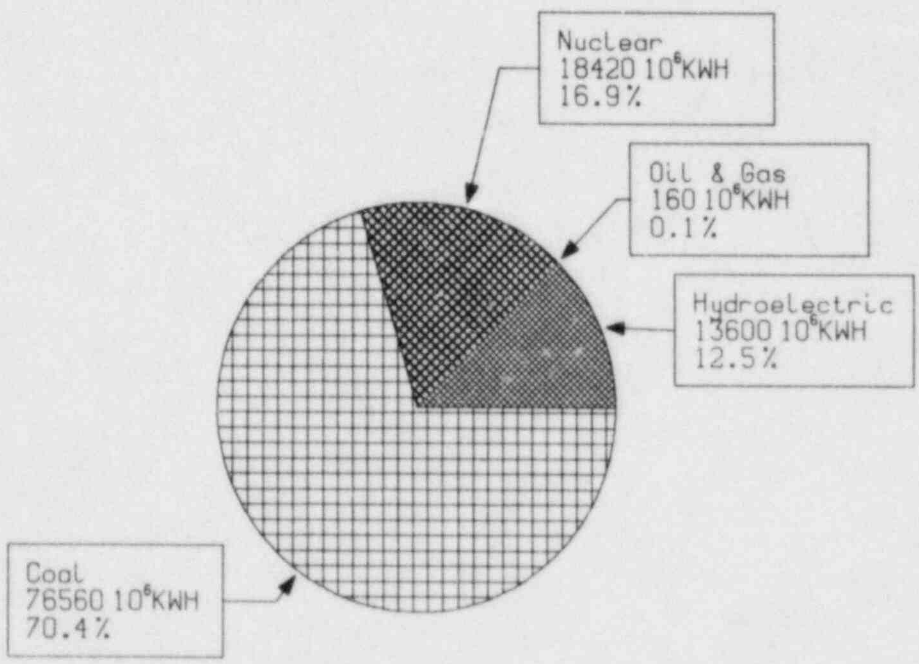


FIGURE 3.18 Nominal Generation in Power Pool 12 in 1984

TABLE 3.12 Composition of Power Pool 14

Characteristic	Year 1984	1985	1986
Total system capacity (end-of-yr MW)	21,000	21,094	23,316
Annual peak load (MW)	16,468	16,682	16,899
Annual energy demand (10^9 kWh)	91	92	93
Annual load factor (%)	63	63	63
Fuel prices (¢/10^6 Btu)			
Nuclear fuel (unit-dependent; excludes fixed carrying charges)	39-63	39-63	39-63
Coal (bituminous, lignite)	210	210	210
Coal (subbituminous, anthracite)	not used	not used	not used
Distillate oil	609	609	609
Residual oil	457	457	457
Gas	505	505	505

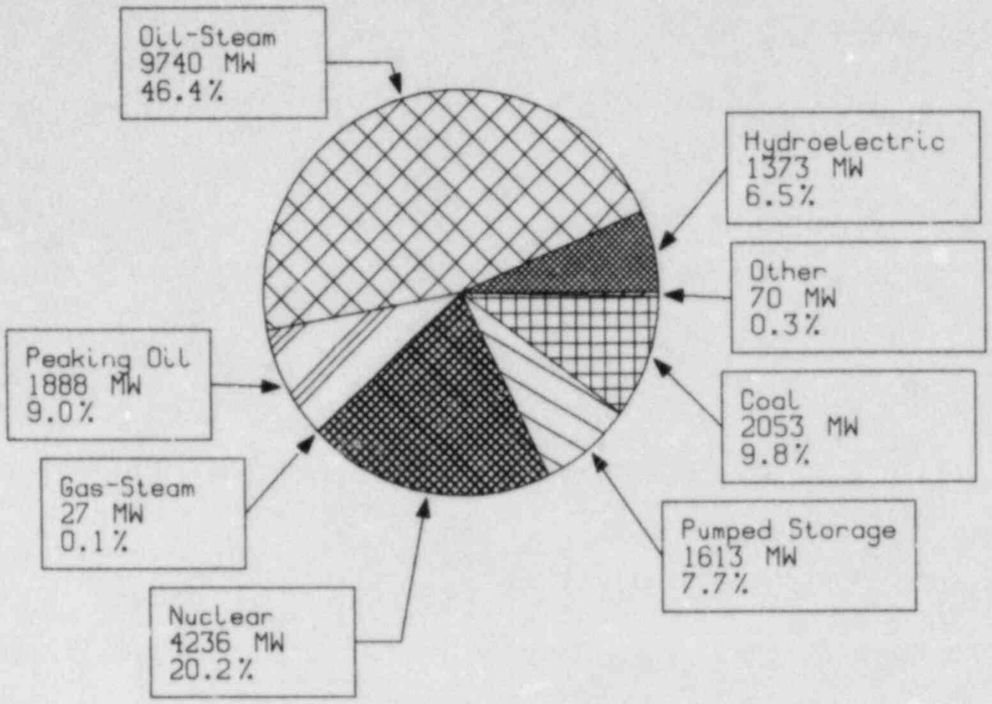


FIGURE 3.19 Expected Capacity in Power Pool 14 at the End of 1984

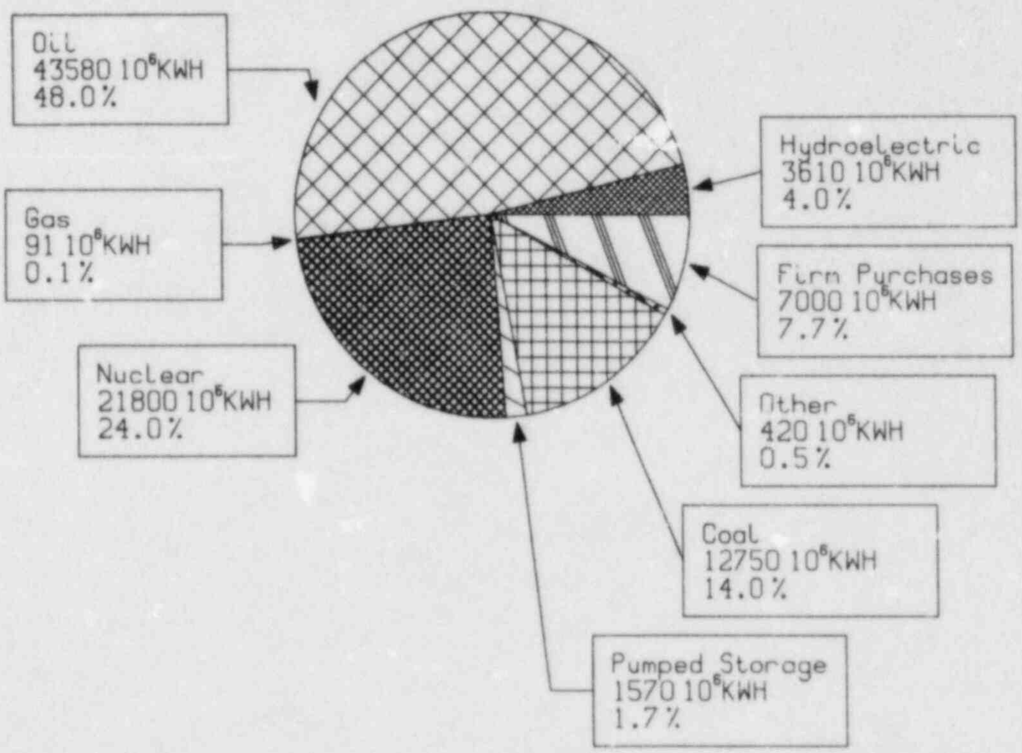


FIGURE 3.20 Nominal Generation in Power Pool 14 in 1984

TABLE 3.13 Composition of Power Pool 15

Characteristic	Year 1984	1985	1986
Total system capacity (end-of-yr MW)	31,197	31,756	33,820
Annual peak load (MW)	21,810	22,115	22,425
Annual energy demand (10^9 kWh)	121	123	124
Annual load factor (%)	63	63	63
Fuel prices (¢/10^6 Btu)			
Nuclear fuel (unit-dependent; excludes fixed carrying charges)	27-69	27-69	27-69
Coal (bituminous, lignite)	178	178	178
Coal (subbituminous, anthracite)	not used	not used	not used
Distillate oil	649	649	649
Residual oil	470	470	470
Gas	405	423	423

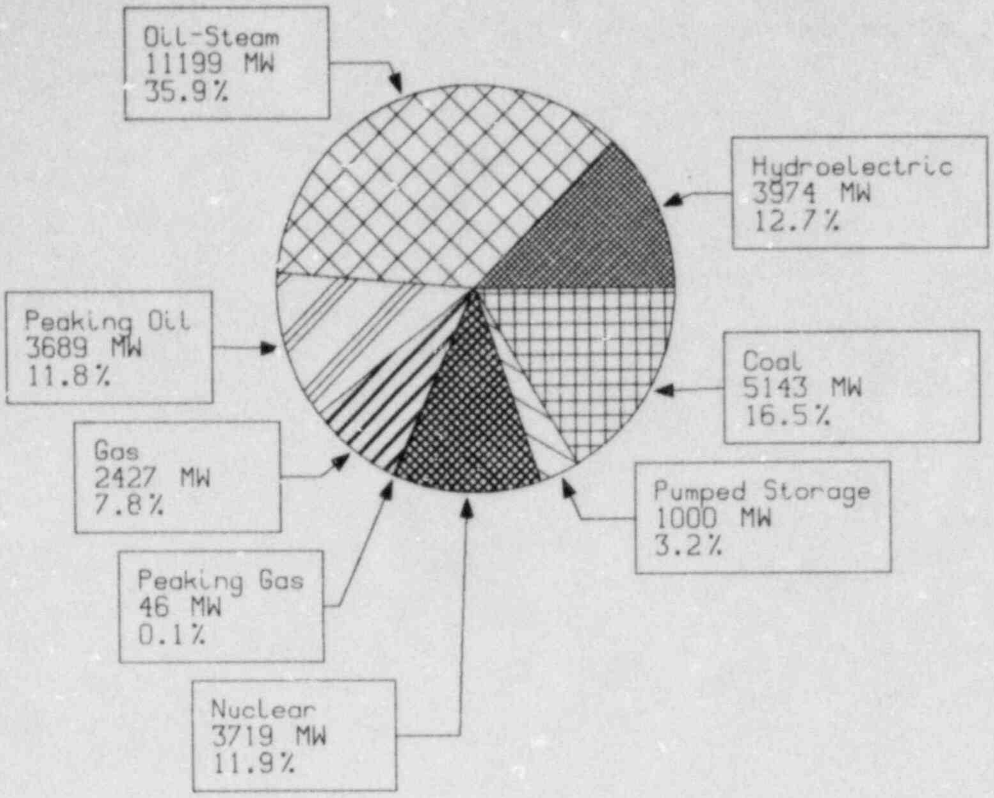


FIGURE 3.21 Expected Capacity in Power Pool 15 at the End of 1984

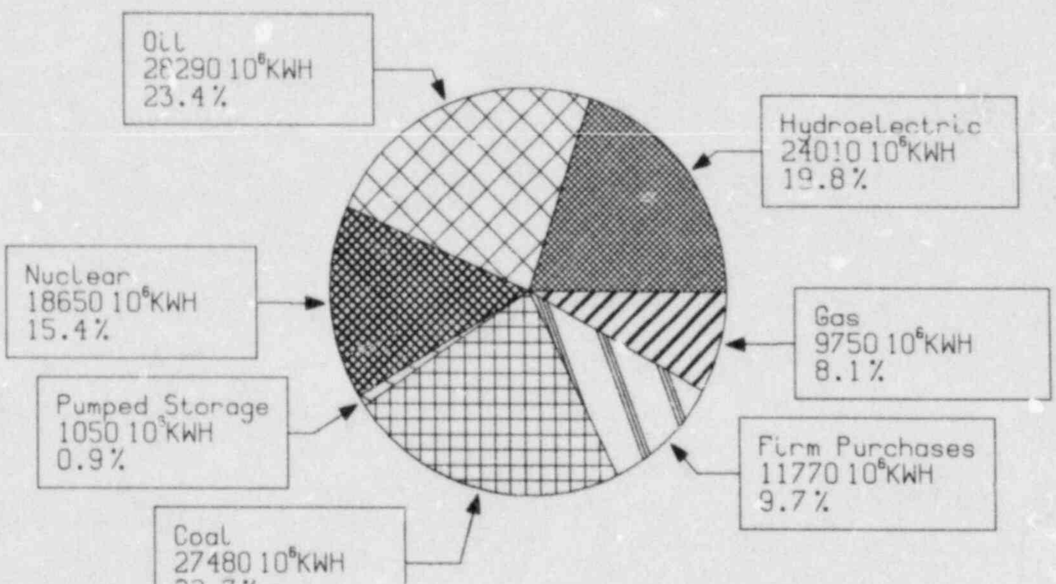


FIGURE 3.22 Nominal Generation in Power Pool 15 in 1984

TABLE 3.14 Composition of Power Pool 16

Characteristic	Year 1984	1985	1986
Total system capacity (end-of-yr MW)	28,701	29,988	29,966
Annual peak load (MW)	21,887	22,850	23,855
Annual energy demand (10^9 kWh)	103	108	112
Annual load factor (%)	54	54	54
Fuel prices (¢/10^6 Btu)			
Nuclear fuel (unit-dependent; excludes fixed carrying charges)	19-73	19-73	19-73
Coal (bituminous, lignite)	209	209	209
Coal (subbituminous, anthracite)	not used	not used	not used
Distillate oil	618	618	618
Residual oil	445	445	445
Gas	288	401	401

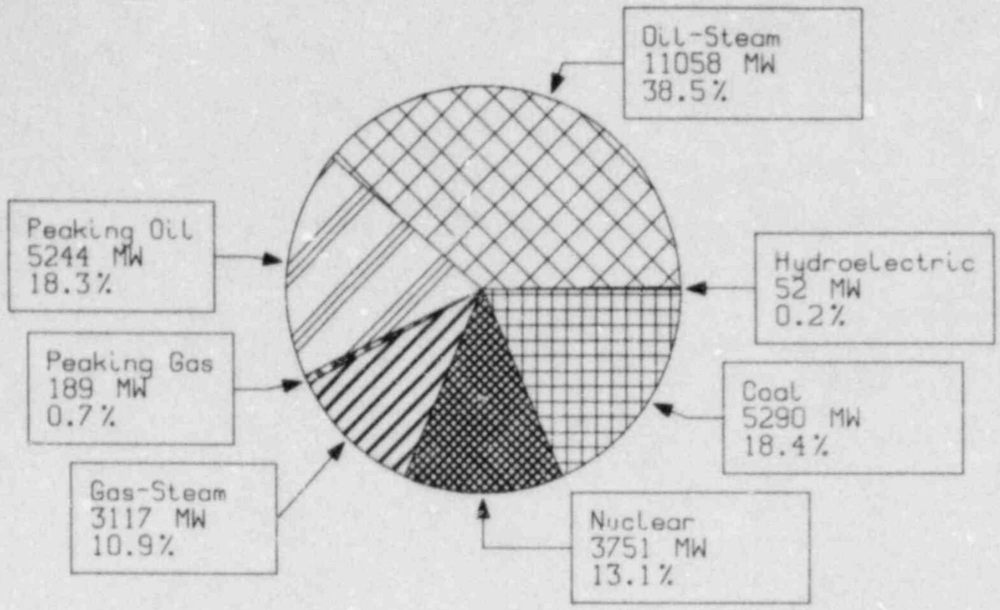


FIGURE 3.23 Expected Capacity in Power Pool 16 at the End of 1984

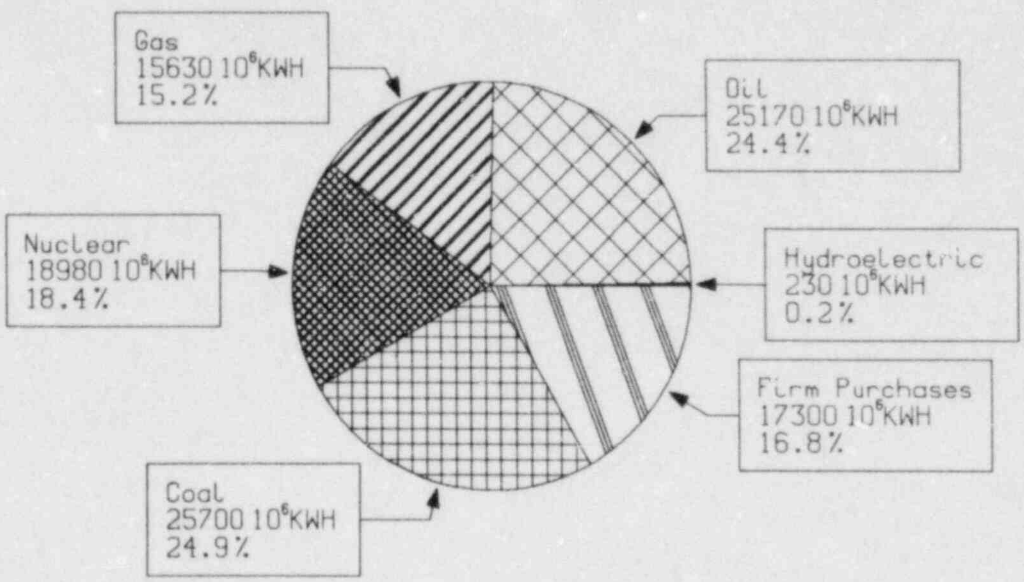


FIGURE 3.24 Nominal Generation in Power Pool 16 in 1984

TABLE 3.15 Composition of Power Pool 17

Characteristic	Year 1984	1985	1986
Total system capacity (end-of-yr MW)	31,457	32,435	32,486
Annual peak load (MW)	22,519	23,150	23,798
Annual energy demand (10^9 kWh)	115	119	122
Total generation including sales (10^9 kWh)	134	149	153
Annual load factor (%)	59	59	59
Fuel prices (¢/10^6 Btu)			
Nuclear fuel (unit-dependent; excludes fixed carrying charges)	34-44	34-44	34-44
Coal (bituminous, lignite)	194	194	194
Coal (subbituminous, anthracite)	not used	not used	not used
Distillate oil	633	633	633
Residual oil	391	391	391
Gas	267	352	352

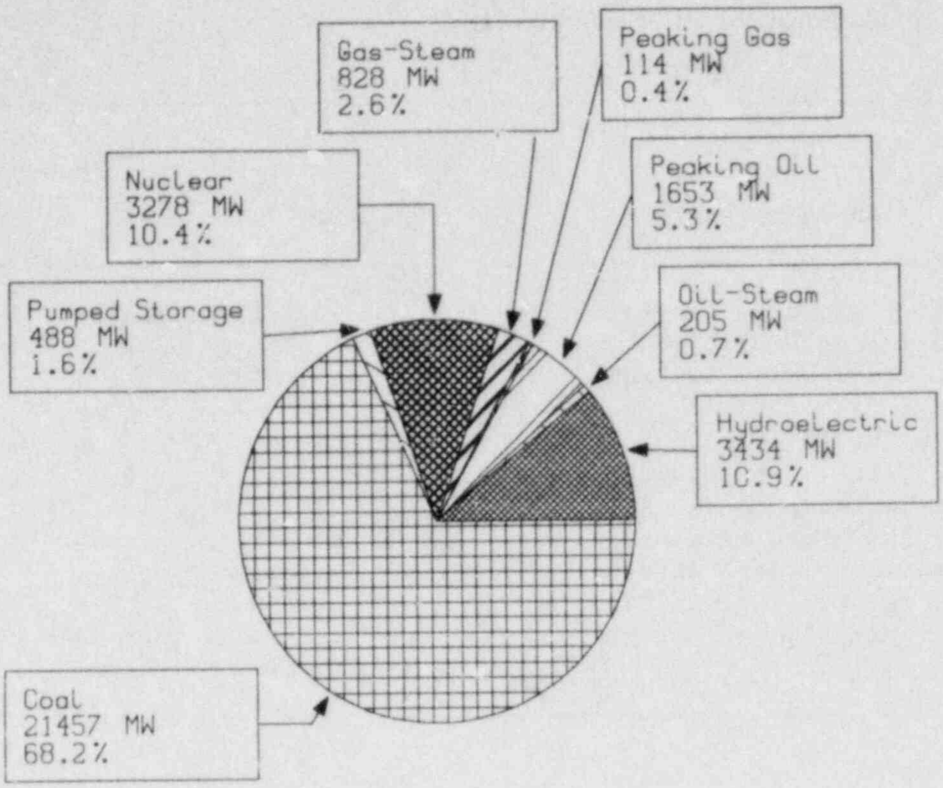


FIGURE 3.25 Expected Capacity in Power Pool 17 at the End of 1984

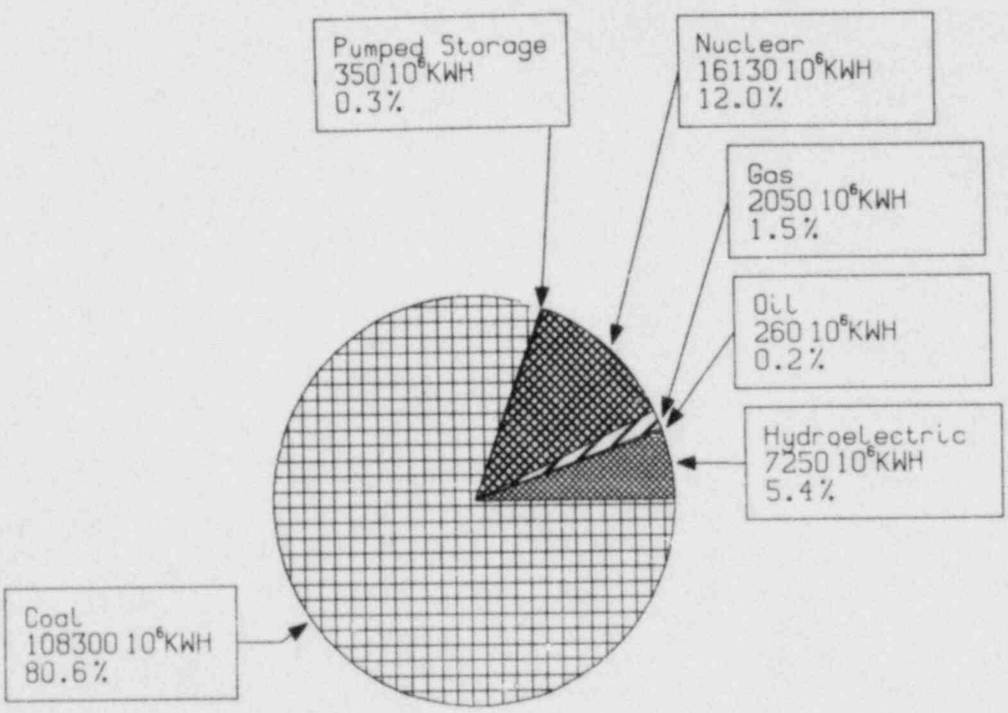


FIGURE 3.26 Nominal Generation in Power Pool 17 in 1984

TABLE 3.16 Composition of Power Pool 18

Characteristic	Year 1984	Year 1985	Year 1986
Total system capacity (end-of-yr MW)	31,376	31,376	32,541
Annual peak load (MW)	19,311	20,141	21,007
Annual energy demand (10^9 kWh)	111	116	121
Annual load factor (%)	66	66	66
Fuel prices (¢/10^6 Btu)			
Nuclear fuel (unit-dependent; excludes fixed carrying charges)	30-33	30-33	30-33
Coal (bituminous, lignite)	185	185	185
Coal (subbituminous, anthracite)	not used	not used	not used
Distillate oil	614	614	614
Residual oil	not used	not used	not used
Gas	270	377	377

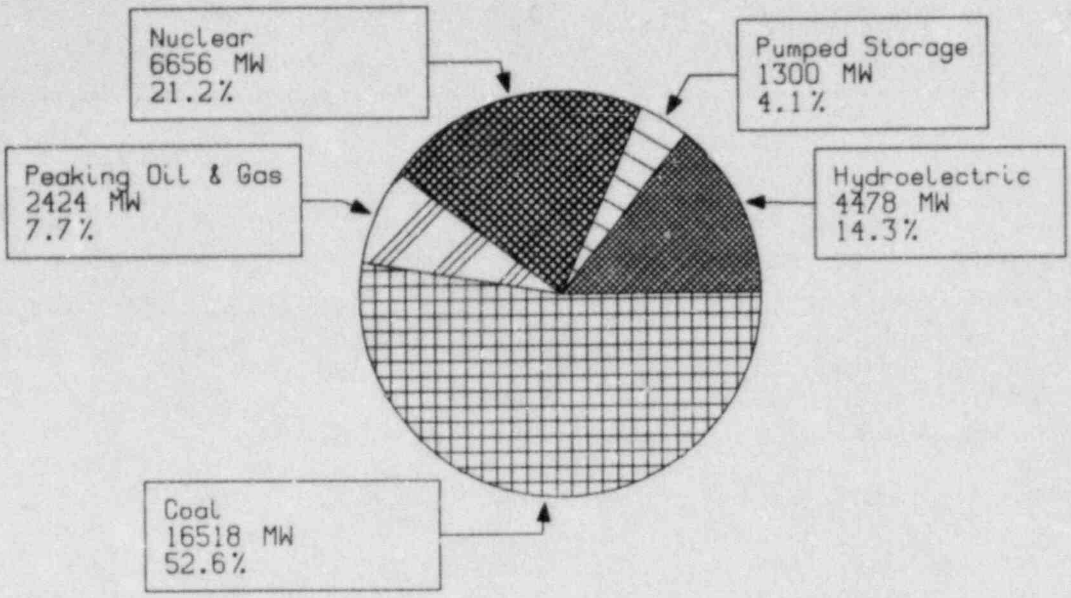


FIGURE 3.27 Expected Capacity in Power Pool 18 at the End of 1984

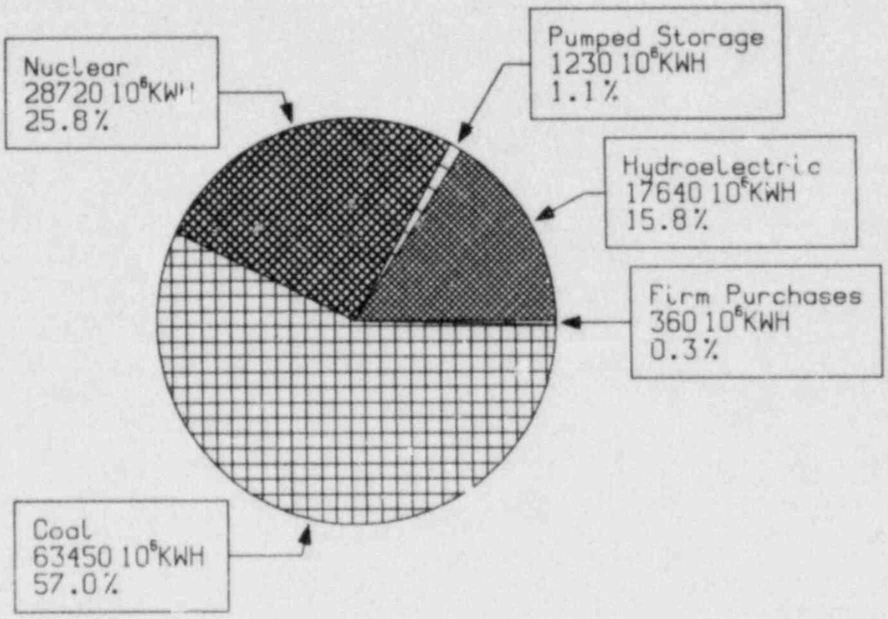


FIGURE 3.28 Nominal Generation in Power Pool 18 in 1984

TABLE 3.17 Composition of Power Pool 19

Characteristic	Year 1984	1985	1986
Total system capacity (end-of-yr MW)	41,004	42,415	44,084
Annual peak load (MW)	31,401	32,186	32,991
Annual energy demand (10^9 kWh)	167	171	176
Total generation including sales (10^9 kWh)	168	174	179
Annual load factor (%)	61	61	61
Fuel prices (¢/10^6 Btu)			
Nuclear fuel (unit-dependent; excludes fixed carrying charges)	26-50	26-50	26-50
Coal (bituminous, lignite)	182	182	182
Coal (subbituminous, anthracite)	not used	not used	not used
Distillate oil	589	589	589
Residual oil	432	432	432
Gas	436	436	436

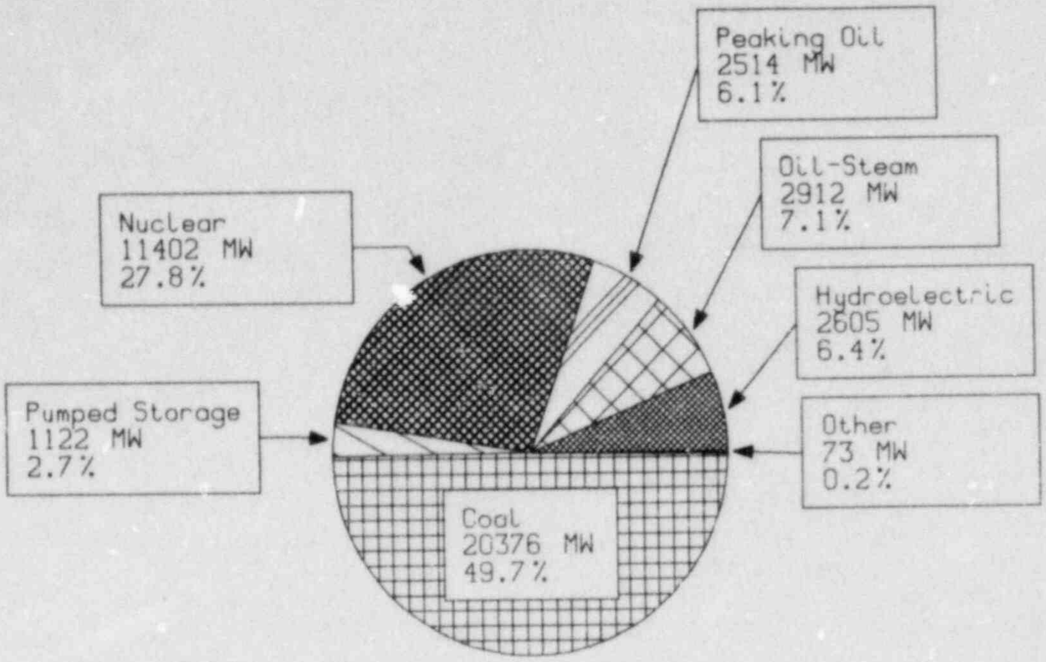


FIGURE 3.29 Expected Capacity in Power Pool 19 at the End of 1984

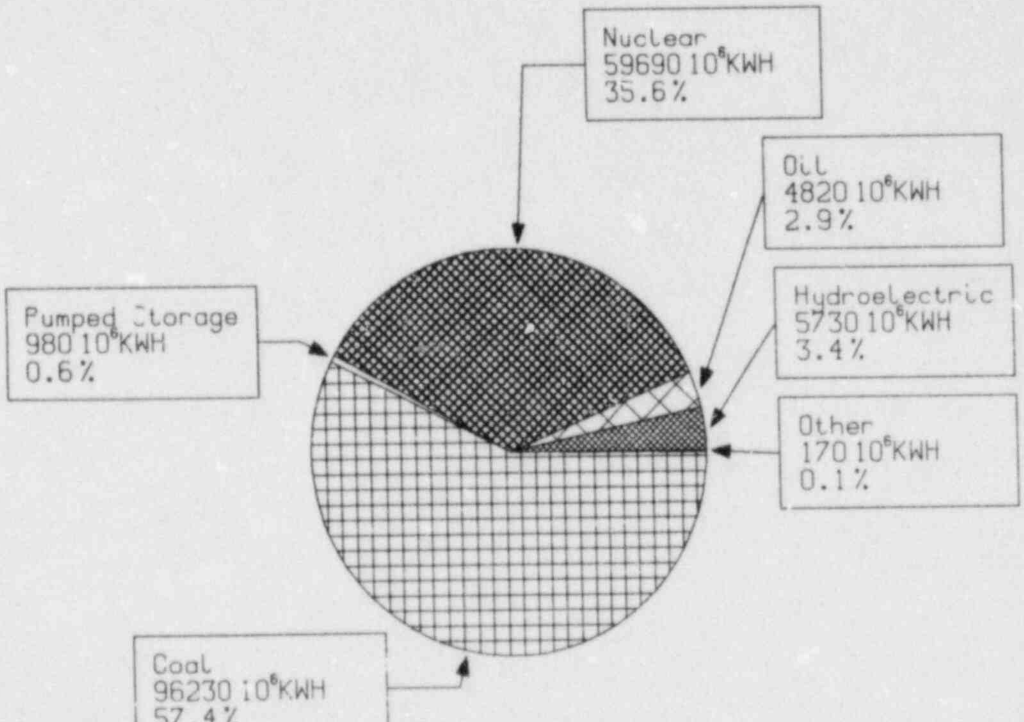


FIGURE 3.30 Nominal Generation in Power Pool 19 in 1984

TABLE 3.18 Composition of Power Pool 20

Characteristic	Year 1984	1985	1986
Total system capacity (end-of-yr MW)	27,166	28,175	28,369
Annual peak load (MW)	19,689	20,122	20,565
Annual energy demand (10^9 kWh)	103	105	108
Annual load factor (%)	60	60	60
Fuel prices (¢/10^6 Btu)			
Nuclear fuel (unit-dependent; excludes fixed carrying charges)	44-50	44-50	44-50
Coal (bituminous, lignite)	207	207	207
Coal (subbituminous, anthracite)	207	207	207
Distillate oil	639	639	639
Residual oil	347	347	347
Gas	296	312	312

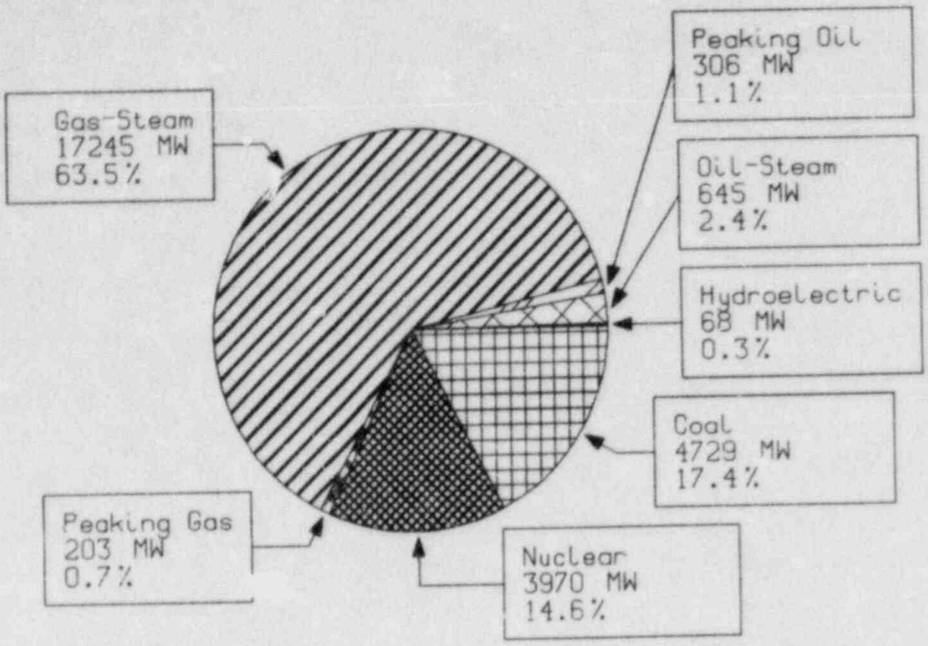


FIGURE 3.31 Expected Capacity in Power Pool 20 at the End of 1984

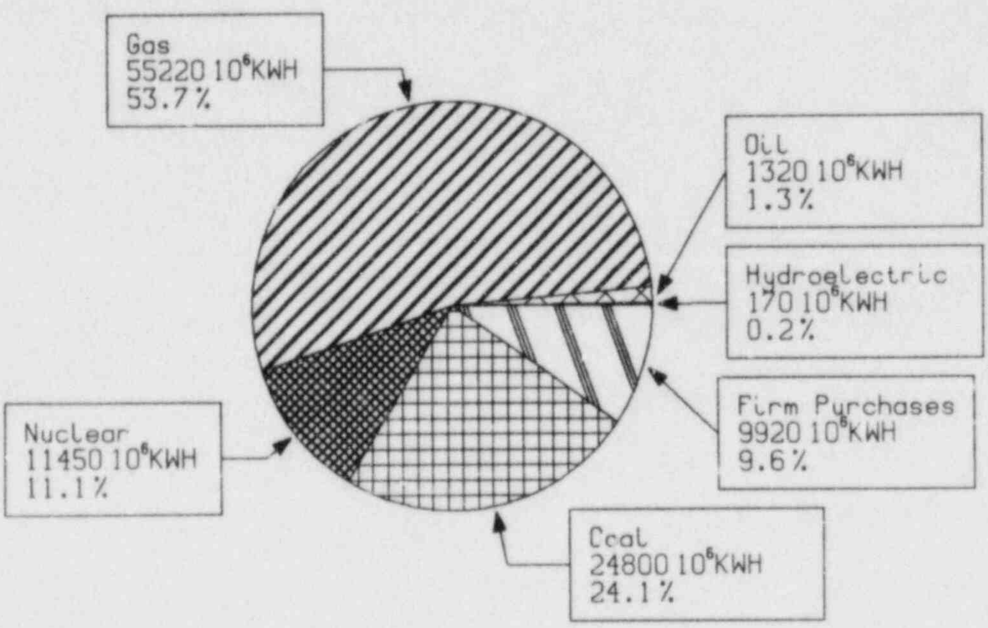


FIGURE 3.32 Nominal Generation in Power Pool 20 in 1984

TABLE 3.19 Composition of Power Pool 22

Characteristic	Year 1984	1985	1986
Total system capacity (end-of-yr MW)	14,838	15,988	16,032
Annual peak load (MW)	10,896	11,212	11,537
Annual energy demand (10^9 kWh)	47	48	49
Total generation including sales (10^9 kWh)	50	51	53
Annual load factor (%)	49	49	49
Fuel prices (¢/10^6 Btu)			
Nuclear fuel (unit-dependent; excludes fixed carrying charges)	50	50	50
Coal (bituminous, lignite)	170	170	170
Coal (subbituminous, anthracite)	131	131	131
Distillate oil	594	594	594
Residual oil	479	479	479
Gas	330	431	431

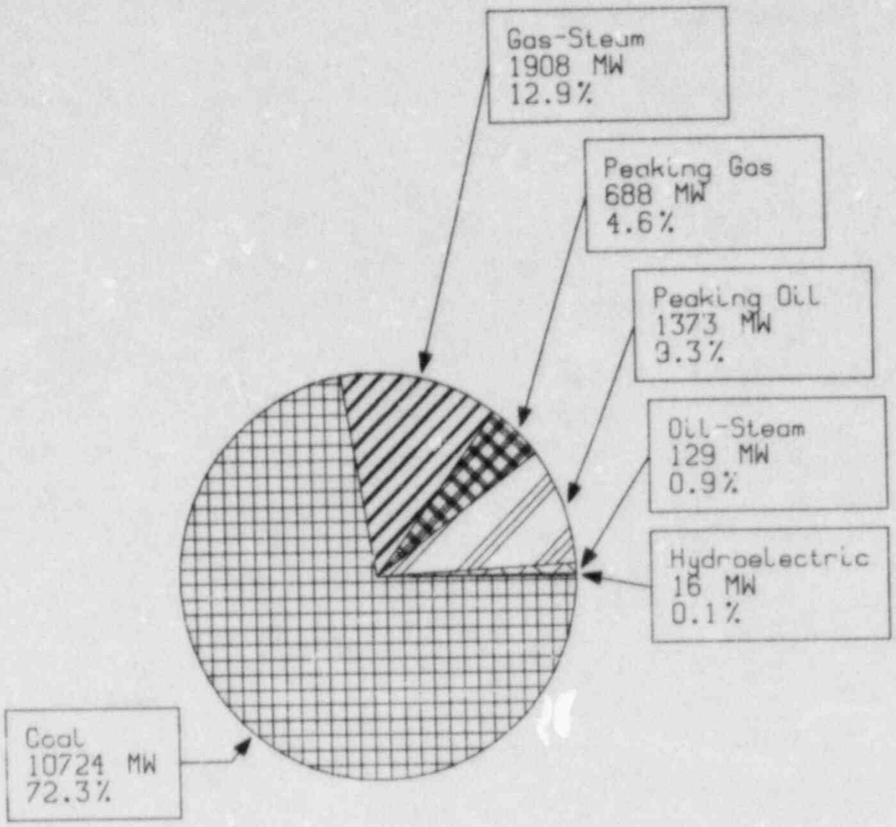


FIGURE 3.33 Expected Capacity in Power Pool 22 at the End of 1984

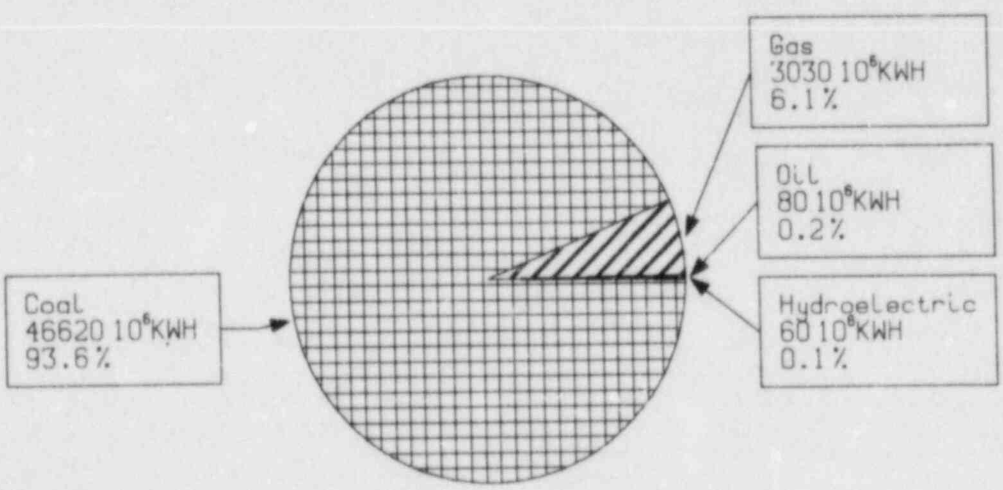


FIGURE 3.34 Nominal Generation in Power Pool 22 in 1984

TABLE 3.20 Composition of Power Pool 25

Characteristic	Year 1984	1985	1986
Total system capacity (end-of-yr MW)	37,718	38,792	39,018
Annual peak load (MW)	31,141	32,013	32,909
Annual energy demand (10^9 kWh)	180	185	190
Total generation including sales (10^9 kWh)	206	211	217
Annual load factor (%)	66	66	66
Fuel prices (¢/10^6 Btu)			
Nuclear fuel (unit-dependent; excludes fixed carrying charges)	47-48	47-48	47-48
Coal (bituminous, lignite)	141	141	141
Coal (subbituminous, anthracite)	99	99	99
Distillate oil	619	619	619
Residual oil	404	404	404
Gas	439	439	439

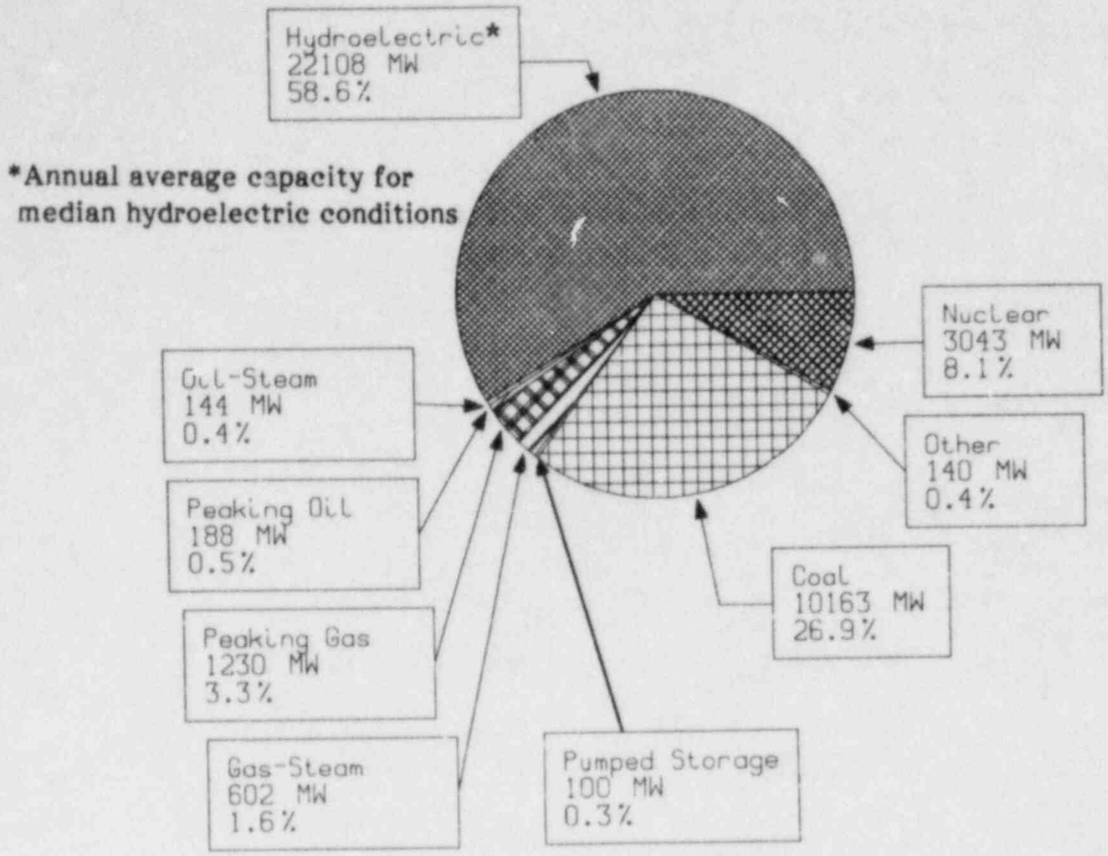


FIGURE 3.35 Expected Capacity in Power Pool 25 at the End of 1984

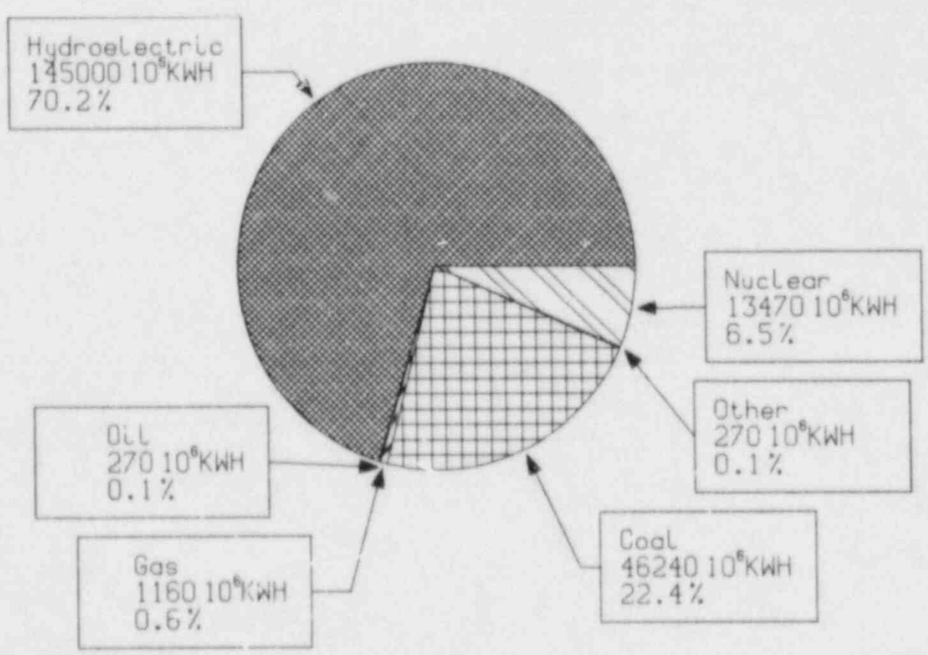


FIGURE 3.36 Nominal Generation in Power Pool 25 in 1984

TABLE 3.21 Composition of Power Pool 26

Characteristic	Year		
	1984	1985	1986
Total system capacity (end-of-yr MW)	13,407	14,735	15,708
Annual peak load (MW)	9,460	10,283	11,178
Annual energy demand (10^9 kWh)	45	49	54
Total generation including sales (10^9 kWh)	49	54	58
Annual load factor (%)	55	55	55
Fuel prices (¢/10^6 Btu)			
Nuclear fuel (unit-dependent; excludes fixed carrying charges)	46	46	46
Coal (bituminous, lignite)	236	236	236
Coal (subbituminous, anthracite)	95	95	95
Distillate oil	619	619	619
Residual oil	434	434	434
Gas	345	391	391

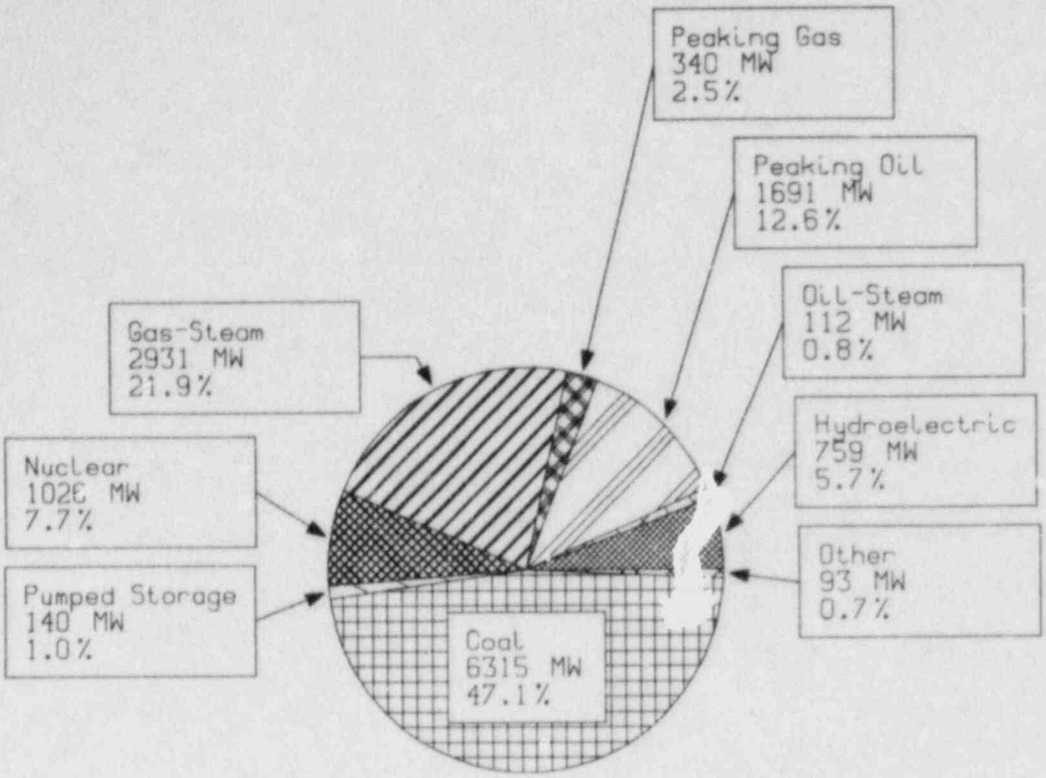


FIGURE 3.37 Expected Capacity in Power Pool 26 at the End of 1984

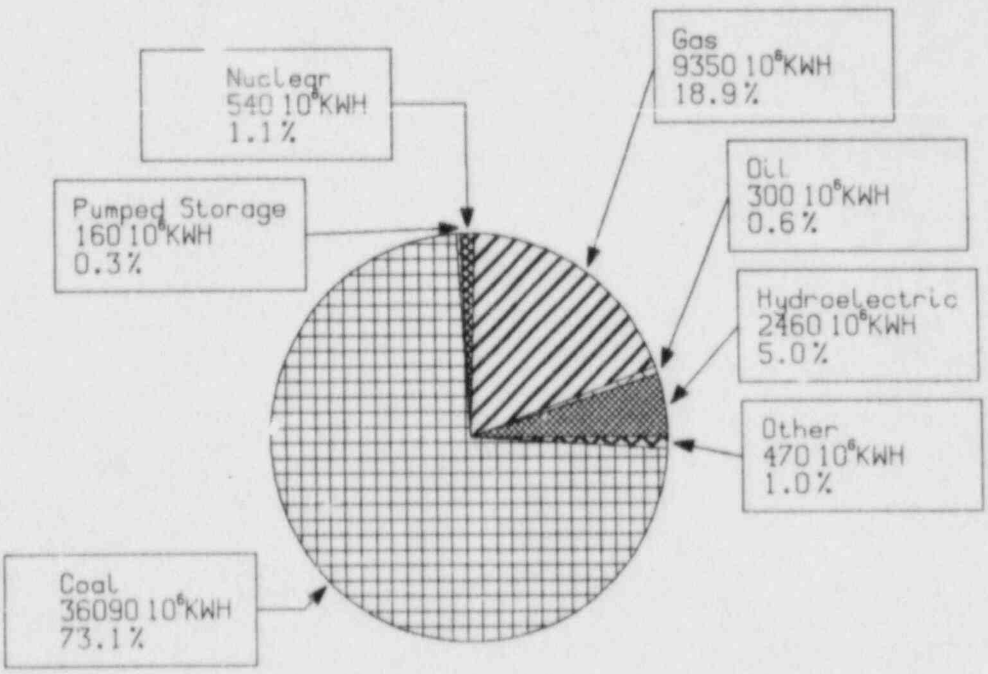


FIGURE 3.38 Nominal Generation in Power Pool 26 in 1984

TABLE 3.22 Composition of Power Pool 27

Characteristic	Year 1984	Year 1985	Year 1986
Total system capacity (end-of-yr MW)	48,507	49,998	49,823
Annual peak load (MW)	38,381	39,225	40,088
Annual energy demand (10^9 kWh)	189	193	198
Annual load factor (%)	56	56	56
Fuel prices (¢/10^6 Btu)			
Nuclear fuel (unit-dependent; excludes fixed carrying charges)	46-93	46-93	46-93
Coal (bituminous, lignite)	157	157	157
Coal (subbituminous, anthracite)	99	99	99
Distillate oil	665	665	665
Residual oil	599	599	599
Gas	490	539	539

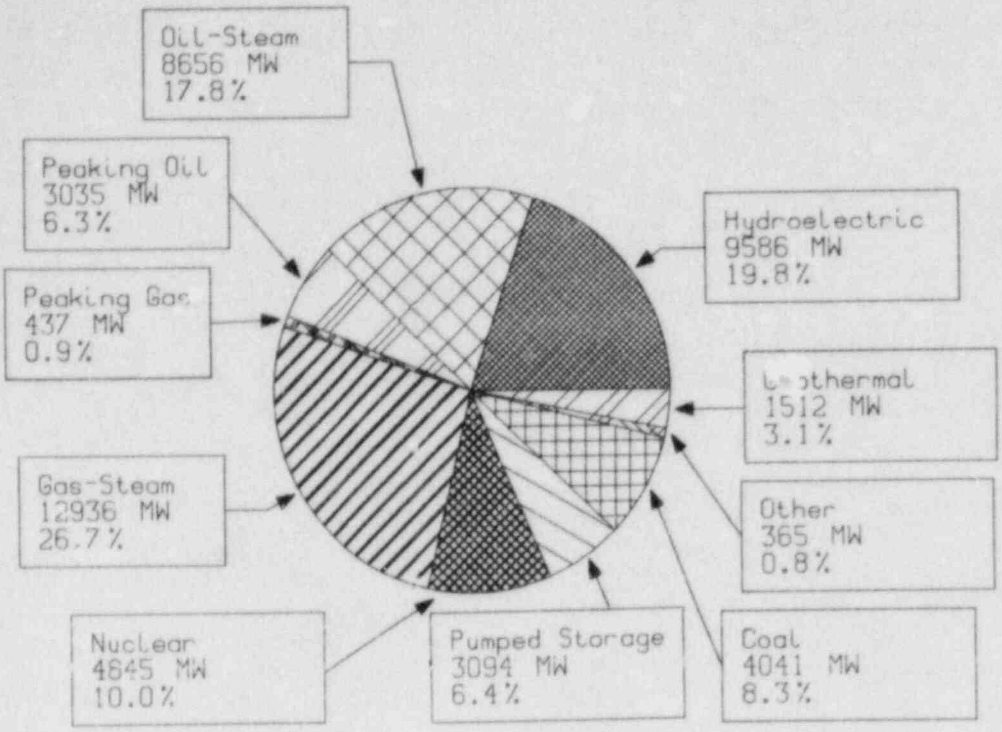


FIGURE 3.39 Expected Capacity in Power Pool 27 at the End of 1984

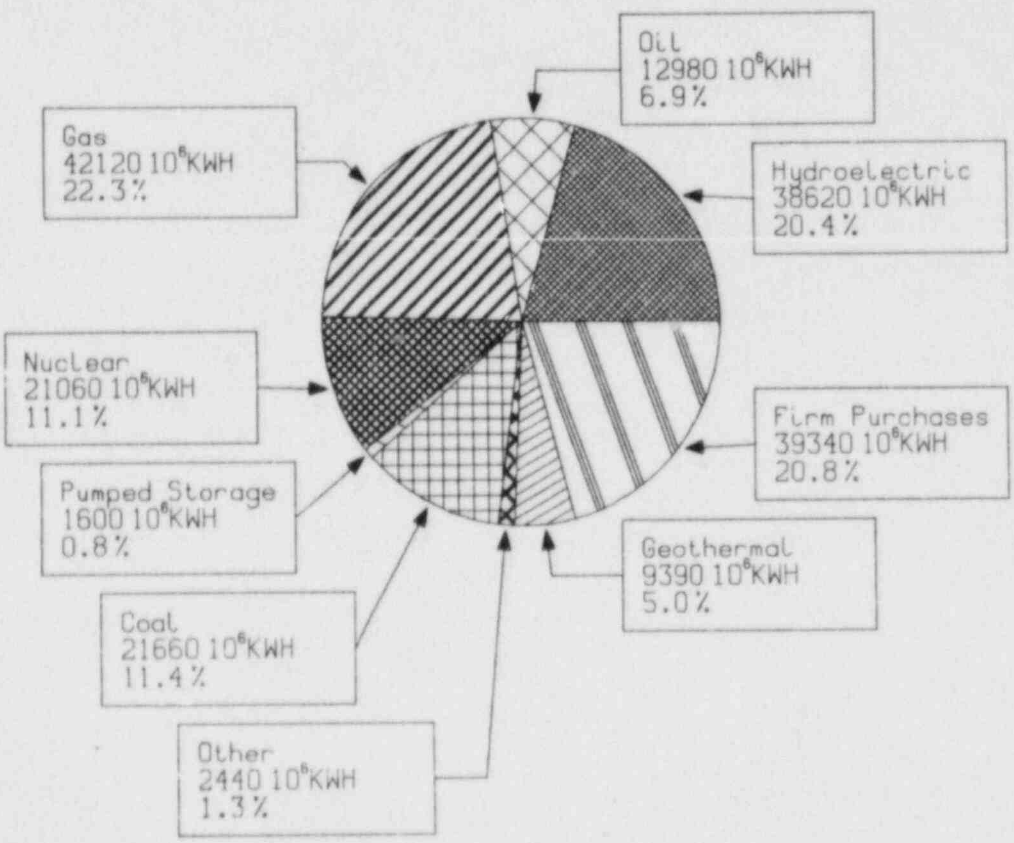


FIGURE 3.40 Nominal Generation in Power Pool 27 in 1984

TABLE 3.23 Composition of Power Pool 28

Characteristic	Year 1984	1985	1986
Total system capacity (end-of-yr MW)	9367	9731	9731
Annual peak load (MW)	5926	6139	6360
Annual energy demand (10^9 kWh)	34	35	37
Total generation including sales (10^9 kWh)	37	38	39
Annual load factor (%)	66	66	66
Fuel prices (¢/10^6 Btu)			
Nuclear fuel (unit-dependent; excludes fixed carrying charges)	33	33	33
Coal (bituminous, lignite)	not used	not used	not used
Coal (subbituminous, anthracite)	100	100	100
Distillate oil	600	600	600
Residual oil	454	454	454
Gas	425	425	425

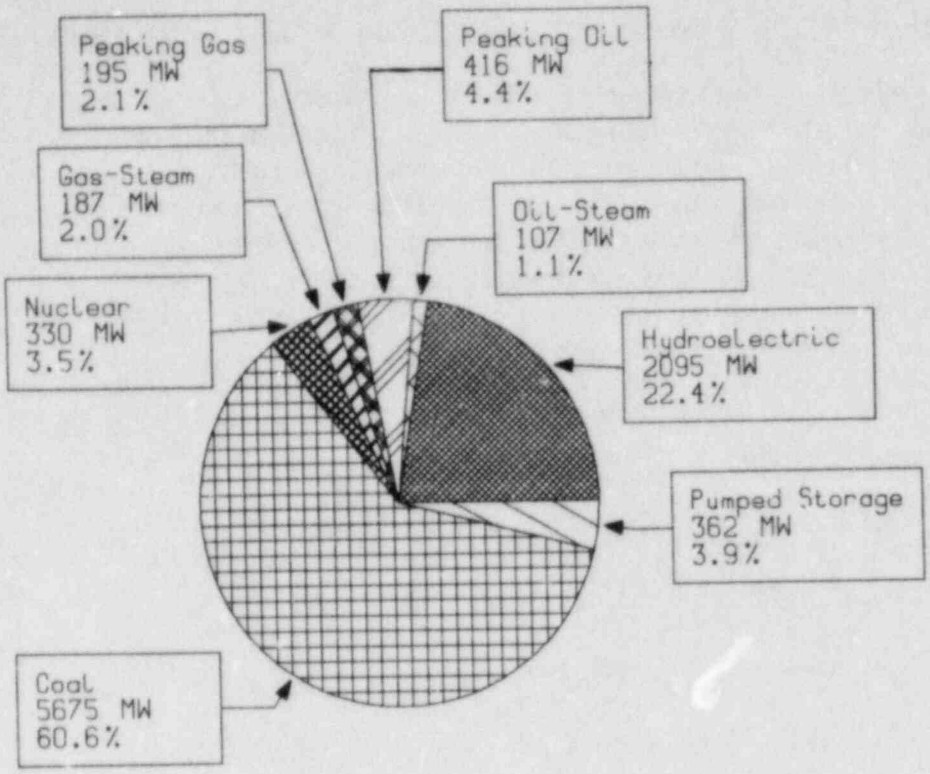


FIGURE 3.41 Expected Capacity in Power Pool 28 at the End of 1984

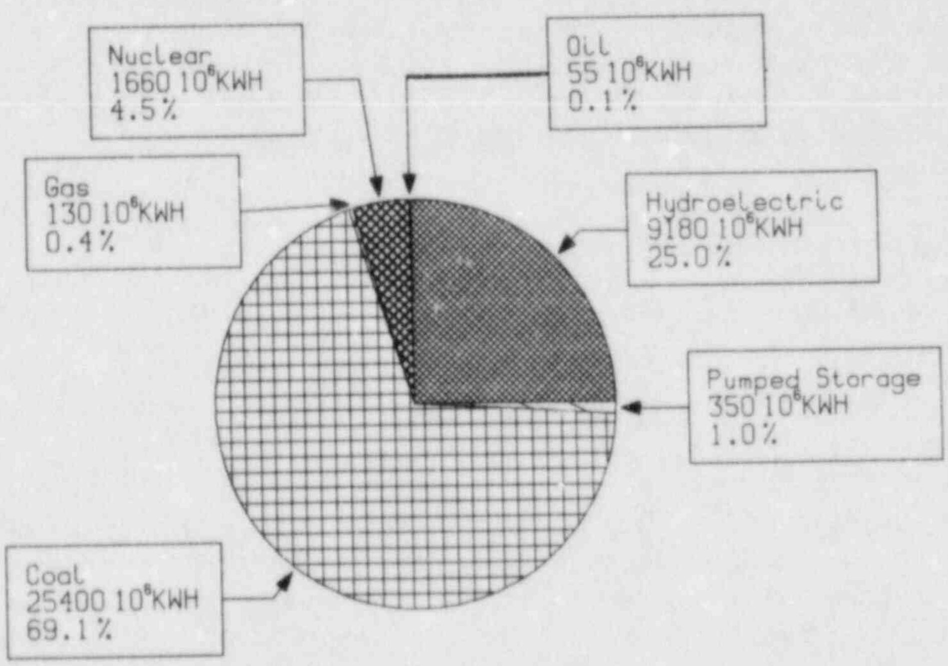


FIGURE 3.42 Nominal Generation in Power Pool 28 in 1984

3.2 INTERPRETATION OF REPLACEMENT ENERGY COST SUMMARIES

Because the production-cost calculations used to estimate replacement energy costs in this study were detailed, some assumptions used in the model were complicated and sometimes difficult to implement. For example, identifying the boundaries for the seasons of the year had to be precise for the model yet convenient for users. Therefore, "nominal" seasons were defined as described below along with other key assumptions and background material. Readers are encouraged to carefully review this section and the following sample calculations in Sec. 3.3. Misinterpretation of the results in Sec. 4 will be much less likely if this information is examined first.

3.2.1 Seasons of the Year

Nominal seasons are defined as follows:

- Spring -- March, April, May
- Summer -- June, July, August
- Fall -- September, October, November
- Winter -- December, January, February

Thus, if a shutdown were contemplated for two weeks in April, the values stated for spring would be appropriate. For modeling, seasons were defined as having exactly 2,190 hours (8,760 hours per year) so that precise season boundaries were 6 a.m., March 2; 12 noon, May 31; 6 p.m., August 30; and 12 midnight, November 30. However, attention to such details is probably more appropriate in a detailed case study for a single reactor than in these seasonal estimates for all 108 reactors.

3.2.2 Reference Date for Costs

All costs and fuel prices are given in 1984 dollars. Replacement energy costs are not discounted.

3.2.3 Generation To Be Replaced

To illustrate the meaning of each entry in the summary tables in Sec. 4, the results for the Comanche Peak 1 reactor are also shown here in Table 3.24. At the time these calculations were performed, Comanche Peak 1 was expected to be brought on line in January 1985. Consequently the column showing generation to be replaced has no entries until winter 1984/85. Generation for that first season is lower than for other seasons, because the unit was assumed to be operational for only two-thirds of winter 1984/85.

TABLE 3.24 Replacement Energy Data for Comanche Peak 1

Reactor Name:	Comanche Peak 1	Unit Size (MW):	1,150
Utility:	Texas Utilities Generating Co.	Heat Rate (Btu/kWh):	11,322
		Variable Fuel Cost (¢/10^6 Btu):	50
Power Pool:	5-6	Operating Status:	Planned
NERC Region:	ERCOT		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	1214	72.3	66.7	44.2	36.4	727
Spring 1985	1819	72.2	100.0	65.7	36.1	720
Summer 1985	1838	73.0	100.0	63.9	34.7	700
Fall 1985	1822	72.3	100.0	64.7	35.5	709
Winter 1985/86	1823	72.4	100.0	65.3	35.8	716
Spring 1986	1820	72.3	100.0	64.8	35.6	711
Summer 1986	1840	73.1	100.0	62.5	34.0	685

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

The generation to be replaced for the remaining seasons is relatively constant. Small differences are caused primarily by variations in loads and the availability of other capacity for generation. The generation to be replaced includes no scheduled maintenance or refueling outages for the reactor of interest, but does include normal maintenance periods for all other units. Maintenance is discussed further in Sec. 3.2.9.

3.2.4 Capacity Factor

The capacity factor for the season equals (generation to be replaced) ÷ (unit size x 2,190 hours). These capacity factors do not account for scheduled maintenance and refueling outages. Methods to account for these outages and adjust the capacity factor are discussed in Sec. 3.2.9 and in the sample calculations in Sec. 3.3.

3.2.5 Portion of Season Unit Is Assumed To Be in Service

The percentage of the season the unit is expected to be in commercial operation is omitted for all seasons before the unit is expected to be brought on line and is 100% for all seasons after the one in which it is brought on line. The value falls between 0 and 100 only in the season the unit is assumed to begin commercial operation. This percentage is independent of maintenance and forced outage considerations; that is, the percentage of time in commercial operation is not the same as unit availability. This value allows some of the following results to be interpreted more easily.

3.2.6 Total Seasonal Production-Cost Increase

Seasonal production-cost increase is the difference between the seasonal production costs with and without operation of the nuclear generating unit of interest. It is measured in millions of 1984 dollars and is not discounted. An unusually low figure, compared to the values for later periods, such as in winter 1984/85 for Comanche Peak in Table 3.24, means that the unit was expected to begin commercial operation during the period and was available for operation during only part of the entire period.

3.2.7 Production-Cost Increase Averaged over Nuclear Energy To Be Replaced

The seasonal production-cost increase divided by the seasonal generation to be replaced is expressed in mills per kilowatt-hour. This value indicates what types of units are providing most of the replacement energy. It can be compared with similar values for other generating units and used to estimate costs for very short outages, such as a few days, and for capacity factors other than the reference values.

In the Comanche Peak example, Fig. 3.8 for Power Pool 5-6 shows that gas-fired generation accounts for more than 64% of 1984 total generation. Thus, one could expect gas-fired generation to supply a large fraction of the replacement energy for Comanche Peak. The fuel prices in Table 3.6 for Power Pool 5-6 show natural gas at $\$3.55/10^6$ Btu and nuclear fuel at $\$0.50/10^6$ Btu. To roughly approximate the cost of replacement energy, assume a heat rate of 11,000 Btu/kWh for both the nuclear and gas-fired steam plants, and a nuclear variable O&M cost of 2.5 mills/kWh. Then:

$$\begin{aligned}\text{Replacement energy cost} &= [(\$3.55 - \$0.50)/10^6 \text{ Btu}](10^3 \text{ mills}/\$1) \\ &\quad \times (11{,}000 \text{ Btu/kWh}) - 2.5 \text{ mills/kWh} \\ &= 31.05 \text{ mills/kWh}\end{aligned}$$

Thus, the replacement generation supplied by gas should cost 31.05 mills/kWh more than the nuclear generation. As Table 3.24 shows, this rough approximation underestimates the findings for Comanche Peak by about 15%. Costs are higher because gas-fired steam units are unable to fully replace the nuclear generation. The required use of higher-priced peaking units causes replacement costs to be higher than estimated in the simple approximation.

3.2.8 Average Daily Production-Cost Increase for Portion of Season Unit is Operating

The seasonal production-cost increase divided by the number of service days in a season (91.25 days for units in operation) is another measure of replacement energy cost. It is useful for estimating the cost of very short term shutdowns, that is, shutdowns of only a few days. For example, a two-day shutdown of Comanche Peak in spring 1985 is estimated to cost 2 x \$720,000, or \$1.440 million.

In the season in which the unit enters commercial operation, the number of service days must be reduced according to the percentage of time the unit is assumed to be in service. The calculation of Comanche Peak costs per day for winter 1984/85 is shown below:

$$\text{Daily cost} = (\$44.2 \times 10^6)/[(91.25\ \text{d})\ (0.667)] = \$726{,}000/\text{d}^*$$

3.2.9 Maintenance

The shutdown costs and reactor generation for each season are based on the assumption that the designated reactor is not scheduled for maintenance or refueling. Although all units in the power pool are scheduled for normal annual maintenance, the results were adjusted, as described in Sec. 2.3.2, to reflect the costs for continuous operation, even in seasons where maintenance was originally scheduled. With this approach, the estimated costs can be easily adjusted to account for various maintenance assumptions. Since maintenance and refueling schedules change so often, it was preferable to determine replacement energy costs that did not depend on a specified, fixed maintenance period for the unit of interest.

Therefore, the sum of the total production-cost increases for the four seasons does not equal the expected annual production-cost increase. To estimate the effect of alternative maintenance and refueling schedules, the replacement energy costs in Tables 4.4-4.111 must be reduced to account for maintenance. Typical annual refueling and maintenance requirements for nuclear units are 8 to 11 weeks/yr, or 1344 to 1848 h/yr.

For example, if Comanche Peak 1 (Table 3.24) were scheduled for 11 weeks of maintenance and refueling in fall 1985, the generation should be reduced by the fraction (2190 - 1848)/2190, or 0.156. Therefore, generation in that season would be only 284 x 10^6 kWh, and the capacity factor would be 0.113. The unit would be in service 15.6% of the season. Replacement energy cost for that season therefore could be calculated as follows:

$$\text{Replacement energy cost} = \$64.7 \times 10^6 \times 0.156 = \$10.1 \times 10^6$$

The production-cost increase averaged over the nuclear energy to be replaced (mills/kWh) remains the same, as does the average daily production-cost increase for portions of season the unit is in service (\$$10^3$/service day).

*The entry in the table (\$727,000/d) differs slightly from this number due to rounding; more significant digits were used for a decimal representation of two-thirds (the fraction of time the unit was in service).

3.3 SAMPLE CALCULATIONS AND GUIDELINES FOR APPLYING RESULTS

This section provides several sample calculations to demonstrate how replacement energy costs for specific periods and other important data can be extracted from the results shown in the tables in Sec. 4. The Comanche Peak 1 example (Table 3.24) will be used for these calculations.

Example 1: Estimate the replacement energy cost of a one-week shutdown of Comanche Peak 1 in summer 1985.

Solution: Use data from Table 3.24 for summer 1985.

Cost = (\$700,000/d) x 7 d
Cost = \$4.9 million (1984 dollars)

Example 2: Estimate the replacement energy cost of a one-year shutdown of Comanche Peak 1 starting in spring 1985.

Solution: The annual cost must account for scheduled maintenance, so the seasonal values in Table 3.24 cannot simply be summed. If no data on maintenance schedules are available, annual cost can be approximated by assuming that maintenance is equally likely in all seasons. For example, if 10 weeks (1680 h) of scheduled maintenance per year are assumed:

$$\text{Cost} = (65.7 + 63.9 + 64.7 + 65.3) \times \$10^6 \times (8760\text{ h} - 1680\text{ h})/8760\text{ h}$$
$$= \$209.8\text{ million}$$

Alternatively, maintenance could be assumed to be most likely when loads for Power Pool 5-6 are lowest, namely spring. In this case, the cost can be estimated as:

$$\text{Cost} = (63.9 + 64.7 + 65.3) \times \$10^6 + (\$65.7 \times 10^6)(2190\text{ h} - 1680\text{ h})/2190\text{ h}$$
$$= \$209.2\text{ million}$$

The cost variation from season to season for reactor shutdowns in other power pools is larger than for Power Pool 5-6. In those cases, the effect of the maintenance timing will be larger.

Example 3: Compute the average daily cost (in dollars) of shutdown from the seasonal shutdown cost for spring 1985.

Solution: $\text{Cost} = (\$65.7 \times 10^6)(1\text{ d} \times 24\text{ h/d})/(2190\text{ h})$
$\text{Cost} = \$0.720\text{ million/d}$

Average daily shutdown costs for each season are shown in Table 3.24 and Tables 4.4-4.111. These figures can be used to calculate costs of very short term shutdowns such as in Example 1 (estimating the cost of a one-week shutdown in summer 1985).

Example 4: What capacity factor is assumed for Comanche Peak 1 for a one-year period beginning in spring 1985?

Solution: The capacity factor assumed for each season is shown in Table 3.24. The annual capacity factor must account for maintenance. Thus, if 10 weeks (1680 h) of scheduled maintenance occur in spring 1985, the capacity factor for the year would be:

$$\text{Capacity factor} = [(0.722)(2190 - 1680)/2190 + 0.730 + 0.723 + 0.724]/4$$
$$= 0.586$$

Example 5: Compute the cost of a one-year shutdown that starts in spring 1985, assuming Comanche Peak 1 would achieve a 74% capacity factor if it were operating.

Solution: Without knowing the maintenance schedule, one can estimate replacement energy cost for any capacity factor by multiplying the production-cost increase averaged over the nuclear energy to be replaced (mills/kWh) by the replacement energy generated (kWh):

$$\text{Replacement energy generated} = (1150 \times 10^3 \text{ kW})(0.74 \times 8760 \text{ h})$$
$$= 7455 \times 10^6 \text{ kWh}$$

Replacement energy cost for
1985 at 74% capacity factor $= [(36.1 + 34.7 + 35.5 + 35.8)/4]$
$\times$ (mills/kWh)($1/10^3$ mills)
$\times$ (7455×10^6 kWh)
= \$265 million

This calculation assumes the cost per unit of replacement energy is constant over the range of nuclear energy replaced. Of course this assumption is true only for small changes from the base values of nuclear energy replaced as listed in Table 3.24. For example, if other reactors in the Power Pool 5-6 were simultaneously shut down, the values in Table 3.24 would underestimate replacement energy cost. Furthermore, this calculation also assumes that the 74% capacity factor already includes an allowance for scheduled maintenance.

Example 6: Estimate the replacement energy cost for winter 1985/86 if the start-up of Comanche Peak 1 is delayed until January 1, 1986.

Solution: Each season is 2190 h or 91.25 d. The winter season begins December 1. Therefore, the first 31 days of winter have no generation from Comanche Peak 1.

$$\text{Cost} = (\$65.3 \times 10^6)(91.25\ d - 31\ d)/91.25\ d$$
$$= \$43.1 \text{ million}$$

4 RESULTS

This section presents results for each reactor expected to be operational at any time between the fall of 1984 and the summer of 1986. One-page summaries display basic background data such as unit size, utility ownership (only one major owner is shown for multiple ownership cases), power pool number, NERC region, and general operating status. Variable nuclear fuel costs and heat rates are also shown for each reactor. Seasonal operating statistics and cost estimates for short-term shutdowns are given in undiscounted 1984 dollars. Table 4.1 provides a guide for locating discussions of specific topics in the text. Users of these data should read the text in full to become familiar with the approach to and assumptions for developing replacement energy costs. The examples given in Sec. 3.3 should be especially helpful for adapting these results to alternative assumptions.

In a comparison of results for two or more units within the same power pool, five key factors must be considered. They are (1) unit size, (2) fuel costs (based on the product of fuel prices and heat rates), (3) loading order (reflected in capacity factor), (4) portion of season unit is expected to be in service, and (5) joint ownership in more than one power pool. With all other conditions being equal, these factors tend to have the following influences on costs as measured in mills per kWh. Larger unit sizes result in higher replacement energy costs. Higher nuclear fuel costs for the reactor of interest yield lower replacement costs. Loading a unit later in the loading order (shown by lower capacity factors) creates two effects. Total dollar costs tend to decrease because fewer kilowatt-hours of replacement energy are required. However, the costs expressed in mills per kilowatt-hour tend to increase because potential sources for replacement energy have higher costs. Units that only operate during a portion of a particular season (i.e., new unit start-ups) may have either higher or lower costs, as expressed in mills per kWh, depending on cost differentials during that season. Units that are jointly owned by two power pools differ from other units because their replacement energy costs are averaged and weighted by the portions in each pool.

Combinations of these factors can lead to cost increases or decreases. Thus, if one compares a larger unit having high fuel costs with a smaller unit having low fuel costs, the net result may be that replacement energy costs are approximately the same in terms of mills per kWh. In contrast, a large unit with low fuel costs would be expected to show noticeably higher replacement energy costs than a small unit with high fuel costs.

Seasonal variations in results are generally linked to peak load cycles, maintenance scheduling, purchases or sales, and hydroelectric cycles. While high peak loads would normally create conditions for high replacement energy costs, they often have the opposite effect because all of the units tend to be scheduled for operation at those times. As a result, most of the low-cost units are available to contribute to replacement generation. During low-load periods, many low-cost units are out of service for routine maintenance, and replacement energy for potential shutdowns must be served by higher-cost units.

TABLE 4.1 Guide to Summary Tables and Specific Topics in Text

Topic of Interest	Location of Related Discussion in Text
Index of Reactors Studied	- Table 4.2: Alphabetical listing of units by NERC region, with power pool and table number of results. - Table 4.3: Alphabetical listing of all units, with NERC region, power pool and table number of results.
Power Pool Definitions	- Sec. 2.3.3, Table 2.1, and Fig. 2.2.
NERC Region Definitions	- Sec. 2.3.3 and Fig. 2.1.
Guidelines for Applying Results	- Discussed in Sec. 3.3, along with examples that demonstrate how to interpret and adjust results for alternative assumptions.
Assumed Reactor Capacities and Start-up Dates	- Listed for each reactor in App. A.
Definitions of Replacement Energy Costs and Unit Operating Statistics	- Sec. 3.2. Related information regarding approach and assumptions discussed in Sec. 3.2.
Seasonal Definitions	- Sec. 3.2.

When seasonal results are compared from one year to the next, three primary factors should be considered. They are: (1) load growth, (2) additions of new units, and (3) real escalation of nuclear O&M costs. Increases in system loads tend to increase replacement energy costs, whereas the addition of new units (presumably relatively low-cost units) tends to reduce costs. The increase in variable nuclear O&M costs, as described in Sec. 2.2.3, causes small reductions in costs compared to assumptions of zero real escalation. Combinations of these factors can result in either cost increases or decreases from year to year.

4.1 INDEX OF NUCLEAR REACTORS STUDIED

This section contains two indexes of reactors that are expected to be operating between fall 1984 and summer 1986 according to the 1984 regional NERC reports.[1-9] The first index (Table 4.2) is organized by NERC region and alphabetized by reactor name. The same ordering is used to display the results in Tables 4.4 through 4.111. The second index (Table 4.3) lists all of the reactors alphabetically but not according to NERC region.

4.2 RESULTS

Tables 4.4 through 4.111 display the seasonal replacement energy costs for each reactor in the investigation. All costs are expressed in undiscounted 1984 dollars and are accompanied by the basic operating statistics that will be useful in examining the effects of alternative short-term shutdown conditions. Again, the reader is urged to read Secs. 2 and 3 (and Sec. 3.3 in particular) for a briefing on key assumptions and appropriate interpretation of these data. The assumption about routine maintenance and refueling is especially important because, with no specified outage for maintenance or refueling, the seasonal costs for replacement energy cannot be simply added to determine annual costs. Annual costs can be estimated by the methods shown in Sec. 3.3, but such longer-term shutdowns would be better characterized by using different assumptions in the analysis.

Reactors that are scheduled to start up within the two-year study period are noted in the summary tables along with their seasonal percentages of service (excluding forced and scheduled outages). For these units, seasonal generation, total dollar costs, and costs averaged over the seasonal generation show that the reactor is not available for generation for part of the study period. The capacity factor and average daily costs have been adjusted for the percentage of time the unit is assumed to be operating.

TABLE 4.2 Index of Reactors by NERC Region

NERC Region and Reactor	Power Pool	Table No.
ECAR		
Beaver Valley 1	2	4.4
Beaver Valley 2	2	4.5
Big Rock Point 1	4	4.6
Donald C. Cook 1	1	4.7
Donald C. Cook 2	1	4.8
Davis-Besse 1	2	4.9
Enrico Fermi 2	4	4.10
Midland 2	4	4.11
Palisades 1	4	4.12
Perry 1	2	4.13
ERCOT		
Comanche Peak 1	5	4.14
Comanche Peak 2	5	4.15
MAAC		
Calvert Cliffs 1	7	4.16
Calvert Cliffs 2	7	4.17
Limerick 1	7	4.18
Oyster Creek 1	7	4.19
Peach Bottom 2	7	4.20
Peach Bottom 3	7	4.21
Salem 1	7	4.22
Salem 2	7	4.23
Susquehanna 1	7	4.24
Susquehanna 2	7	4.25
Three Mile Island 1	7	4.26
MAIN		
Braidwood 1	8	4.27
Byron 1	8	4.28
Byron 2	8	4.29
Callaway 1	10	4.30
Dresden 2	8	4.31
Dresden 3	8	4.32
Kewaunee 1	11	4.33
LaSalle 1	8	4.34
LaSalle 2	8	4.35
Point Beach 1	11	4.36
Point Beach 2	11	4.37
Quad-Cities 1[a]	8,12	4.38
Quad-Cities 2[a]	8,12	4.39
Zion 1	8	4.40
Zion 2	8	4.41
MAPP		
Duane Arnold 1	12	4.42
Cooper 1	12	4.43
Fort Calhoun 1	12	4.44
LaCrosse 5	12	4.45
Monticello 1	12	4.46
Prairie Island 1	12	4.47
Prairie Island 2	12	4.48
NPCC		
Fitzpatrick 1	15	4.49
Ginna 1	15	4.50
Haddam Neck 1	14	4.51
Indian Point 2	15	4.52
Indian Point 3	15	4.53
Maine Yankee 1	14	4.54
Millstone 1	14	4.55
Millstone 2	14	4.56
Millstone 3	14	4.57
Nine Mile Point 1	15	4.58
Pilgrim 1	14	4.59
Seabrook 1	14	4.60
Shoreham 1	15	4.61
Vermont Yankee 1	14	4.62
Yankee Rowe 1	14	4.63
SERC		
Browns Ferry 1	18	4.64
Browns Ferry 2	18	4.65
Browns Ferry 3	18	4.66
Brunswick 1	19	4.67
Brunswick 2	19	4.68
Catawba 1	19	4.69
Crystal River 3	16	4.70
Farley 1	17	4.71
Farley 2	17	4.72
Harris 1	17	4.73
Hatch 1	17	4.74
Hatch 2	17	4.75
McGuire 1	19	4.76
McGuire 2	19	4.77
North Anna 1	19	4.78
North Anna 2	19	4.79
Oconee 1	19	4.80
Oconee 2	19	4.81
Oconee 3	19	4.82
Robinson 2	19	4.83
Sequoyah 1	18	4.84
Sequoyah 2	18	4.85
St. Lucie 1	16	4.86
St. Lucie 2	16	4.87
Surry 1	19	4.88
Surry 2	19	4.89
Turkey Point 3	16	4.90
Turkey Point 4	16	4.91
V.C. Summer 1	19	4.92
Watts Bar 1	18	4.93
SPP		
Arkansas Nuclear One 1	20	4.94
Arkansas Nuclear One 2	20	4.95
Grand Gulf 1[a]	20,17	4.96
River Bend 1	20	4.97
Waterford 3	20	4.98
Wolf Creek 1	22	4.99
WSCC		
Diablo Canyon 1	27	4.100
Diablo Canyon 2	27	4.101
Fort St. Vrain 1	28	4.102
Hanford N 1	25	4.103
Palo Verde 1[a]	26,27	4.104
Palo Verde 2[a]	26,27	4.105
Rancho Seco 1	27	4.106
San Onofre 1	27	4.107
San Onofre 2	27	4.108
San Onofre 3	27	4.109
Trojan 1	25	4.110
WNP 2	25	4.111

[a]Units jointly owned by more than one power pool.

TABLE 4.3 Alphabetical List of Nuclear Reactors Included in the Study

Name	Power Pool	NERC Region	Table No.	Name	Power Pool	NERC Region	Table No.
Arkansas Nuclear One 1	20	SPP	4.94	Millstone 1	14	NPCC	4.55
				Millstone 2	14	NPCC	4.56
Arkansas Nuclear One 2	20	SPP	4.95	Millstone 3	14	NPCC	4.57
				Monticello 1	12	MAPP	4.46
Duane Arnold 1	12	MAPP	4.42	Nine Mile Point 1	15	NPCC	4.58
Beaver Valley 1	2	ECAR	4.4	North Anna 1	19	SERC	4.78
Beaver Valley 2	2	ECAR	4.5	North Anna 2	19	SERC	4.79
Big Rock Point 1	4	ECAR	4.6	Oconee 1	19	SERC	4.80
Braidwood 1	8	MAIN	4.27	Oconee 2	19	SERC	4.81
Browns Ferry 1	18	SERC	4.64	Oconee 3	19	SERC	4.82
Browns Ferry 2	18	SERC	4.65	Oyster Creek 1	7	MAAC	4.19
Browns Ferry 3	18	SERC	4.66	Palisades 1	4	ECAR	4.12
Brunswick 1	19	SERC	4.67	Palo Verde 1[a]	26,27	WSCC	4.104
Brunswick 2	19	SERC	4.68	Palo Verde 2[a]	26,27	WSCC	4.105
Byron 1	8	MAIN	4.28	Peach Bottom 2	7	MAAC	4.20
Byron 2	8	MAIN	4.29	Peach Bottom 3	7	MAAC	4.21
Callaway 1	10	MAIN	4.30	Perry 1	2	ECAR	4.13
Calvert Cliffs 1	7	MAAC	4.16	Pilgrim 1	14	NPCC	4.59
Calvert Cliffs 2	7	MAAC	4.17	Point Beach 1	11	MAIN	4.36
Catawba 1	19	SERC	4.69	Point Beach 2	11	MAIN	4.37
Comanche Peak 1	5	ERCOT	4.14	Prairie Island 1	12	MAPP	4.47
Comanche Peak 2	5	ERCOT	4.15	Prairie Island 2	12	MAPP	4.48
Donald C. Cook 1	1	ECAR	4.7	Quad-Cities 1[a]	8,12	MAIN	4.38
Donald C. Cook 2	1	ECAR	4.8	Quad-Cities 2[a]	8,12	MAIN	4.39
Cooper 1	12	MAPP	4.43	Rancho Seco 1	27	WSCC	4.106
Crystal River 3	16	SERC	4.70	River Bend 1	20	SPP	4.97
Davis-Besse 1	2	ECAR	4.9	Robinson 2	19	SERC	4.83
Diablo Canyon 1	27	WSCC	4.100	Salem 1	7	MAAC	4.22
Diablo Canyon 2	27	WSCC	4.101	Salem 2	7	MAAC	4.23
Dresden 2	8	MAIN	4.31	San Onofre 1	27	WSCC	4.107
Dresden 3	8	MAIN	4.32	San Onofre 2	27	WSCC	4.108
Enrico Fermi 2	4	ECAR	4.10	San Onofre 3	27	WSCC	4.109
Farley 1	17	SERC	4.71	Seabrook 1	14	NPCC	4.60
Farley 2	17	SERC	4.72	Sequoyah 1	18	SERC	4.84
Fitzpatrick 1	15	NPCC	4.49	Sequoyah 2	18	SERC	4.85
Fort Calhoun 1	12	MAPP	4.44	Shoreham 1	15	NPCC	4.61
Fort St. Vrain 1	28	WSCC	4.102	St. Lucie 1	16	SERC	4.86
Ginna 1	15	NPCC	4.50	St. Lucie 2	16	SERC	4.87
Grand Gulf 1[a]	20,17	SPP	4.96	Surry 1	19	SERC	4.88
Haddam Neck 1	14	NPCC	4.51	Surry 2	19	SERC	4.89
Hanford N 1	25	WSCC	4.103	Susquehanna 1	7	MAAC	4.24
Harris 1	17	SERC	4.73	Susquehanna 2	7	MAAC	4.25
Hatch 1	17	SERC	4.74	Three Mile Island 1	7	MAAC	4.26
Hatch 2	17	SERC	4.75	Trojan 1	25	WSCC	4.110
Indian Point 2	15	NPCC	4.52	Turkey Point 3	16	SERC	4.90
Indian Point 3	15	NPCC	4.53	Turkey Point 4	16	SERC	4.91
Kewaunee 1	11	MAIN	4.33	V.C. Summer 1	19	SERC	4.92
LaCrosse 5	12	MAPP	4.45	Vermont Yankee 1	14	NPCC	4.62
LaSalle 1	8	MAIN	4.34	WNP-2 2	25	WSCC	4.111
LaSalle 2	8	MAIN	4.35	Waterford 3	20	SPP	4.98
Limerick 1	7	MAAC	4.18	Watts Bar 1	18	SERC	4.93
Maine Yankee 1	14	NPCC	4.54	Wolf Creek 1	22	SPP	4.99
McGuire 1	19	SERC	4.76	Yankee Rowe 1	14	NPCC	4.63
McGuire 2	19	SERC	4.77	Zion 1	8	MAIN	4.40
Midland 2	4	ECAR	4.11	Zion 2	8	MAIN	4.41

[a]Jointly owned units with portions of ownership in more than one power pool.

TABLE 4.4 Replacement Energy Data for Beaver Valley 1

Reactor Name:	Beaver Valley 1	Unit Size (MW):	810
Utility:	Duquesne Light Co. (Major Owner)	Heat Rate (Btu/kWh):	11,438
		Variable Fuel Cost (¢/10^6 Btu):	26
Power Pool:	2	Operating Status:	In Service
NERC Region:	ECAR		

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1287	72.5	100.0	28.0	21.8	307
Winter 1984/85	1287	72.6	100.0	25.8	20.0	282
Spring 1985	1286	72.5	100.0	25.2	19.6	276
Summer 1985	1286	72.5	100.0	24.7	19.2	271
Fall 1985	1286	72.5	100.0	25.2	19.6	277
Winter 1985/86	1286	72.5	100.0	23.6	18.3	258
Spring 1986	1285	72.4	100.0	23.4	18.2	256
Summer 1986	1284	72.4	100.0	22.5	17.5	247

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.5 Replacement Energy Data for Beaver Valley 2

Reactor Name:	Beaver Valley 2	Unit Size (MW):	833
Utility:	Duquesne Light Co. (Major Owner)	Heat Rate (Btu/kWh):	11,438
		Variable Fuel Cost (¢/10^6 Btu):	26
Power Pool:	2	Operating Status:	Planned
NERC Region:	ECAR		

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	-	-	-	-	-	-
Spring 1985	-	-	-	-	-	-
Summer 1985	-	-	-	-	-	-
Fall 1985	-	-	-	-	-	-
Winter 1985/86	-	-	-	-	-	-
Spring 1986	440	72.3	33.3	7.7	17.6	254
Summer 1986	1321	72.4	100.0	23.2	17.6	254

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.6 Replacement Energy Data for Big Rock Point 1

Reactor Name:	Big Rock Point 1	Unit Size (MW):	64
Utility:	Consumers Power Co.	Heat Rate (Btu/kWh):	11,477
Power Pool:	4	Variable Fuel Cost (¢/10^6 Btu):	38
NERC Region:	ECAR	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	105	75.0	100.0	3.4	32.1	37
Winter 1984/85	105	75.0	100.0	3.3	31.1	36
Spring 1985	104	74.1	100.0	2.9	28.1	32
Summer 1985	103	73.7	100.0	2.6	25.6	29
Fall 1985	104	74.3	100.0	3.0	29.0	33
Winter 1985/86	104	74.5	100.0	2.9	27.3	31
Spring 1986	104	74.0	100.0	2.7	26.2	30
Summer 1986	103	73.7	100.0	2.5	24.4	28

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.7 Replacement Energy Data for Donald C. Cook 1

Reactor Name:	Donald C. Cook 1	Unit Size (MW):	1,020
Utility:	Indiana and Michigan Electric Co.	Heat Rate (Btu/kWh):	10,770
		Variable Fuel Cost (¢/10^6 Btu):	42
Power Pool:	1	Operating Status:	In Service
NERC Region:	ECAR		

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1615	72.3	100.0	27.6	17.1	302
Winter 1984/85	1613	72.2	100.0	26.6	16.5	292
Spring 1985	1612	72.2	100.0	26.4	16.4	289
Summer 1985	1612	72.2	100.0	26.3	16.3	288
Fall 1985	1613	72.2	100.0	26.5	16.4	290
Winter 1985/86	1613	72.2	100.0	25.8	16.0	283
Spring 1986	1614	72.2	100.0	25.9	16.0	284
Summer 1986	1614	72.2	100.0	25.8	16.0	283

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.8 Replacement Energy Data for Donald C. Cook 2

Reactor Name:	Donald C. Cook 2	Unit Size (MW):	1,060
Utility:	Indiana and Michigan Electric Co.	Heat Rate (Btu/kWh):	10,770
		Variable Fuel Cost (¢/10^6 Btu):	42
Power Pool:	1	Operating Status:	In Service
NERC Region:	ECAR		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1678	72.3	100.0	28.7	17.1	315
Winter 1984/85	1676	72.2	100.0	27.7	16.5	304
Spring 1985	1675	72.2	100.0	[illegible]	16.4	301
Summer 1985	1675	72.2	100.0	27.3	16.3	299
Fall 1985	1675	72.2	100.0	27.5	16.4	301
Winter 1985/86	1676	72.2	100.0	26.8	16.0	294
Spring 1986	1677	72.2	100.0	26.9	16.0	295
Summer 1986	1676	72.2	100.0	26.7	16.0	293

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.9 Replacement Energy Data for Davis-Besse 1

Reactor Name:	Davis-Besse 1	Unit Size (MW):	874
Utility:	Toledo Edison Co. (Major Owner)	Heat Rate (Btu/kWh):	10,844
		Variable Fuel Cost (¢/10^6 Btu):	39
Power Pool:	2	Operating Status:	In Service
NERC Region:	ECAR		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1388	72.5	100.0	28.5	20.5	312
Winter 1984/85	1387	72.5	100.0	26.1	18.8	286
Spring 1985	1385	72.4	100.0	25.5	18.4	279
Summer 1985	1387	72.5	100.0	24.9	18.0	273
Fall 1985	1387	72.5	100.0	25.4	18.3	279
Winter 1985/86	1387	72.5	100.0	23.7	17.1	260
Spring 1986	1386	72.4	100.0	23.4	16.9	257
Summer 1986	1384	72.3	100.0	22.6	16.3	248

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.10 Replacement Energy Data for Enrico Fermi 2

Reactor Name:	Enrico Fermi 2	Unit Size (MW):	1,093
Utility:	Detroit Edison Co. (Major Owner)	Heat Rate (Btu/kWh):	11,629
		Variable Fuel Cost (¢/10^6 Btu):	54
Power Pool:	4	Operating Status:	Planned
NERC Region:	ECAR		

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	1788	74.7	100.0	55.6	31.1	610
Spring 1985	1770	73.9	100.0	47.1	26.6	516
Summer 1985	1760	73.5	100.0	43.7	24.8	479
Fall 1985	1773	74.1	100.0	50.4	28.4	552
Winter 1985/86	1775	74.1	100.0	49.4	27.8	541
Spring 1986	1764	73.7	100.0	45.9	26.0	503
Summer 1986	1759	73.5	100.0	42.1	23.9	461

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.11 Replacement Energy Data for Midland 2

Reactor Name:	Midland 2	Unit Size (MW):	818
Utility:	Consumers Power Co.	Heat Rate (Btu/kWh):	11,629
Power Pool:	4	Variable Fuel Cost (¢/10^6 Btu):	55
NERC Region:	ECAR	Operating Status:	Planned

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	-	-	-	-	-	-
Spring 1985	-	-	-	-	-	-
Summer 1985	-	-	-	-	-	-
Fall 1985	-	-	-	-	-	-
Winter 1985/86	-	-	-	-	-	-
Spring 1986	-	-	-	-	-	-
Summer 1986	877	73.4	66.7	20.3	23.2	334

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.12 Replacement Energy Data for Palisades 1

Reactor Name:	Palisades 1	Unit Size (MW):	635
Utility:	Consumers Power Co.	Heat Rate (Btu/kWh):	11,629
Power Pool:	4	Variable Fuel Cost (¢/10^6 Btu):	55
NERC Region:	ECAR	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1040	74.8	100.0	33.3	32.0	365
Winter 1984/85	1040	74.8	100.0	31.7	30.5	347
Spring 1985	1029	74.0	100.0	27.2	26.5	299
Summer 1985	1024	73.6	100.0	24.9	24.3	273
Fall 1985	1032	74.2	100.0	28.4	27.5	311
Winter 1985/86	1034	74.3	100.0	27.7	26.8	303
Spring 1986	1025	73.7	100.0	26.6	25.9	291
Summer 1986	1023	73.6	100.0	23.9	23.4	262

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.13 Replacement Energy Data for Perry 1

Reactor Name:	Perry 1	Unit Size (MW):	1,205
Utility:	Cleveland Electric Illuminating Co. (Major Owner)	Heat Rate (Btu/kWh):	10,844
		Variable Fuel Cost (¢/10^6 Btu):	39
Power Pool:	2	Operating Status:	Planned
NERC Region:	ECAR		

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	-	-	-	-	-	-
Spring 1985	636	72.3	33.3	11.4	17.9	374
Summer 1985	1909	72.3	100.0	34.8	18.2	381
Fall 1985	1911	72.4	100.0	35.3	18.5	387
Winter 1985/86	1908	72.3	100.0	33.1	17.3	363
Spring 1986	1907	72.3	100.0	32.7	17.1	358
Summer 1986	1907	72.3	100.0	31.5	16.5	345

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.14 Replacement Energy Data for Comanche Peak 1

Reactor Name:	Comanche Peak 1	Unit Size (MW):	1,150
Utility:	Texas Utilities Generating Co.	Heat Rate (Btu/kWh):	11,322
		Variable Fuel Cost (¢/10^6 Btu):	50
Power Pool:	5-6	Operating Status:	Planned
NERC Region:	ERCOT		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	1214	72.3	66.7	44.2	36.4	727
Spring 1985	1819	72.2	100.0	65.7	36.1	720
Summer 1985	1838	73.0	100.0	63.9	34.7	700
Fall 1985	1822	72.3	100.0	64.7	35.5	709
Winter 1985/86	1823	72.4	100.0	65.3	35.8	716
Spring 1986	1820	72.3	100.0	64.8	35.6	711
Summer 1986	1840	73.1	100.0	62.5	34.0	685

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.15 Replacement Energy Data for Comanche Peak 2

Reactor Name:	Comanche Peak 2	Unic Size (MW):	1,150
Utility:	Texas Utilities Generating Co. (Major Owner)	Heat Rate (Btu/kWh):	11,322
		Variable Fuel Cost (¢/10^6 Btu):	50
Power Pool:	5-6	Operating Status:	Planned
NERC Region:	ERCOT		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	-	-	-	-	-	-
Spring 1985	-	-	-	-	-	-
Summer 1985	-	-	-	-	-	-
Fall 1985	-	-	-	-	-	-
Winter 1985/86	-	-	-	-	-	-
Spring 1986	-	-	-	-	-	-
Summer 1986	1228	73.1	66.7	41.6	33.9	684

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.16 Replacement Energy Data for Calvert Cliffs 1

Reactor Name:	Calvert Cliffs 1	Unit Size (MW):	825
Utility:	Baltimore Gas and Electric Co.	Heat Rate (Btu/kWh):	10,861
		Variable Fuel Cost (¢/10^6 Btu):	41
Power Pool:	7	Operating Status:	In Service
NERC Region:	MAAC		

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1318	72.9	100.0	45.7	34.7	501
Winter 1984/85	1313	72.7	100.0	44.3	33.8	486
Spring 1985	1310	72.5	100.0	44.2	33.8	485
Summer 1985	1309	72.5	100.0	32.0	24.5	351
Fall 1985	1312	72.6	100.0	40.9	31.2	449
Winter 1985/86	1314	72.7	100.0	43.3	33.0	475
Spring 1986	1311	72.6	100.0	43.7	33.3	479
Summer 1986	1310	72.5	100.0	33.2	25.3	364

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.17 Replacement Energy Data for Calvert Cliffs 2

Reactor Name:	Calvert Cliffs 2	Unit Size (MW):	825
Utility:	Baltimore Gas and Electric Co.	Heat Rate (Btu/kWh):	10,861
		Variable Fuel Cost ($¢/10^6$ Btu):	41
Power Pool:	7	Operating Status:	In Service
NERC Region:	MAAC		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1318	72.9	100.0	45.7	34.7	501
Winter 1984/85	1313	72.7	100.0	44.3	33.8	486
Spring 1985	1310	72.5	100.0	44.2	33.8	485
Summer 1985	1309	72.4	100.0	32.0	24.5	351
Fall 1985	1312	72.6	100.0	40.9	31.2	449
Winter 1985/86	1314	72.7	100.0	43.3	33.0	475
Spring 1986	1311	72.6	100.0	43.7	33.4	479
Summer 1986	1310	72.5	100.0	33.2	25.3	364

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.18 Replacement Energy Data for Limerick 1

Reactor Name:	Limerick 1	Unit Size (MW):	1,065
Utility:	Philadelphia Electric Co.	Heat Rate (Btu/kWh):	10,960
Power Pool:	7	Variable Fuel Cost (¢/10^6 Btu):	45
NERC Region:	MAAC	Operating Status:	Planned

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	-	-	-	-	-	-
Spring 1985	1126	72.4	66.7	35.8	31.8	589
Summer 1985	1689	72.4	100.0	40.9	24.2	448
Fall 1985	1691	72.5	100.0	52.4	31.0	574
Winter 1985/86	1695	72.7	100.0	55.5	32.7	608
Spring 1986	1692	72.5	100.0	55.9	33.0	612
Summer 1986	1690	72.5	100.0	42.1	24.9	461

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.19 Replacement Energy Data for Oyster Creek 1

Reactor Name:	Oyster Creek 1	Unit Size (MW):	620
Utility:	GPU Nuclear Corp.	Heat Rate (Btu/kWh):	11,672
Power Pool:	7	Variable Fuel Cost (¢/10^6Btu):	27
NERC Region:	MAAC	Operating Status:	In Service

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	991	73.0	100.0	35.8	36.1	392
Winter 1984/85	987	72.7	100.0	34.4	34.8	377
Spring 1985	985	72.5	100.0	34.3	34.8	376
Summer 1985	984	72.5	100.0	25.1	25.5	275
Fall 1985	985	72.5	100.0	32.0	32.5	351
Winter 1985/86	988	72.8	100.0	33.7	34.1	369
Spring 1986	986	72.6	100.0	34.0	34.5	373
Summer 1986	985	72.5	100.0	26.0	26.4	285

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.20 Replacement Energy Data for Peach Bottom 2

Reactor Name:	Peach Bottom 2	Unit Size (MW):	1,051
Utility:	Philadelphia Electric Co. (Major Owner)	Heat Rate (Btu/kWh):	10,708
Power Pool:	7	Variable Fuel Cost (¢/10^6 Btu):	64
NERC Region:	MAAC	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1677	72.9	100.0	54.2	32.3	594
Winter 1984/85	1672	72.6	100.0	52.7	31.5	578
Spring 1985	1669	72.5	100.0	52.7	31.6	578
Summer 1985	1666	72.4	100.0	37.2	22.3	407
Fall 1985	1669	72.5	100.0	48.6	29.1	533
Winter 1985/86	1673	72.7	100.0	51.5	30.8	564
Spring 1986	1669	72.5	100.0	52.0	31.1	570
Summer 1986	1668	72.5	100.0	38.5	23.1	422

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.21 Replacement Energy Data for Peach Bottom 3

Reactor Name:	Peach Bottom 3	Unit Size (MW):	1,035
Utility:	Philadelphia Electric Co. (Major Owner)	Heat Rate (Btu/kWh):	10,708
		Variable Fuel Cost (¢/10^6 Btu):	64
Power Pool:	7	Operating Status:	In Service
NERC Region:	MAAC		

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1651	72.8	100.0	53.4	32.3	585
Winter 1984/85	1646	72.6	100.0	51.9	31.5	569
Spring 1985	1643	72.5	100.0	51.9	31.6	569
Summer 1985	1641	72.4	100.0	36.6	22.3	401
Fall 1985	1643	72.5	100.0	47.8	29.1	524
Winter 1985/86	1647	72.7	100.0	50.7	30.8	556
Spring 1986	1644	72.5	100.0	51.2	31.1	561
Summer 1986	1642	72.5	100.0	37.9	23.0	415

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.22 Replacement Energy Data for Salem 1

Reactor Name:	Salem 1	Unit Size (MW):	1,079
Utility:	Public Service Electric and Gas Co. (Major Owner)	Heat Rate (Btu/kWh):	10,960
Power Pool:	7	Variable Fuel Cost (¢/10^6 Btu):	45
NERC Region:	MAAC	Operating Status:	In Service

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1723	72.9	100.0	58.9	34.2	645
Winter 1984/85	1717	72.7	100.0	57.4	33.4	629
Spring 1985	1713	72.5	100.0	57.4	33.5	629
Summer 1985	1712	72.4	100.0	41.4	24.2	454
Fall 1985	1714	72.5	100.0	53.1	31.0	582
Winter 1985/86	1718	72.7	100.0	56.2	32.7	616
Spring 1986	1714	72.5	100.0	56.6	33.0	620
Summer 1986	1713	72.5	100.0	42.6	24.9	467

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.23 Replacement Energy Data for Salem 2

Reactor Name:	Salem 2	Unit Size (MW):	1,106
Utility:	Public Service Electric and Gas Co. (Major Owner)	Heat Rate (Btu/kWh):	10,960
		Variable Fuel Cost (¢/10^6 Btu):	45
Power Pool:	7	Operating Status:	In Service
NERC Region:	MAAC		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1765	72.9	100.0	60.3	34.2	661
Winter 1984/85	1760	72.7	100.0	58.9	33.5	646
Spring 1985	1756	72.5	100.0	58.8	33.5	644
Summer 1985	1754	72.4	100.0	42.5	24.2	466
Fall 1985	1756	72.5	100.0	54.5	31.0	598
Winter 1985/86	1761	72.7	100.0	57.7	32.7	632
Spring 1986	1757	72.5	100.0	58.0	33.0	636
Summer 1986	1756	72.5	100.0	43.7	24.9	478

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.24 Replacement Energy Data for Susquehanna 1

Reactor Name:	Susquehanna 1	Unit Size (MW):	1,032
Utility:	Pennsylvania Power and Light Co.	Heat Rate (Btu/kWh):	10,960
		Variable Fuel Cost (¢/10^6 Btu):	45
Power Pool:	7	Operating Status:	In Service
NERC Region:	MAAC		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1646	72.8	100.0	56.3	34.2	617
Winter 1984/85	1641	72.6	100.0	54.8	33.4	601
Spring 1985	1638	72.5	100.0	54.8	33.5	601
Summer 1985	1636	72.4	100.0	39.5	24.2	433
Fall 1985	1638	72.5	100.0	50.7	31.0	556
Winter 1985/86	1643	72.7	100.0	53.6	32.7	588
Spring 1986	1639	72.5	100.0	54.1	33.0	593
Summer 1986	1637	72.5	100.0	40.8	24.9	447

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.25 Replacement Energy Data for Susquehanna 2

Reactor Name:	Susquehanna 2	Unit Size (MW):	1,052
Utility:	Pennsylvania Power and Light Co. (Major Owner)	Heat Rate (Btu/kWh):	10,960
		Variable Fuel Cost (¢/10^6 Btu):	45
Power Pool:	7	Operating Status:	Planned
NERC Region:	MAAC		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	558	72.7	33.3	21.2	38.0	697
Winter 1984/85	1674	72.6	100.0	55.9	33.4	613
Spring 1985	1670	72.5	100.0	55.9	33.5	613
Summer 1985	1668	72.4	100.0	40.3	24.2	442
Fall 1985	1670	72.5	100.0	51.8	31.0	568
Winter 1985/86	1675	72.7	100.0	54.7	32.6	599
Spring 1986	1671	72.5	100.0	55.2	33.0	605
Summer 1986	1670	72.5	100.0	41.6	24.9	456

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.26 Replacement Energy Data for Three Mile Island 1

Reactor Name:	Three Mile Island 1	Unit Size (MW):	776
Utility:	GPU Nuclear Corp. (Major Owner)	Heat Rate (Btu/kWh):	10,960
		Variable Fuel Cost (¢/10^6 Btu):	45
Power Pool:	7	Operating Status:	Planned
NERC Region:	MAAC		

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	823	72.6	66.7	26.4	32.1	433
Spring 1985	1232	72.5	100.0	40.9	33.2	448
Summer 1985	1231	72.4	100.0	29.4	23.9	322
Fall 1985	1232	72.5	100.0	37.9	30.8	416
Winter 1985/86	1236	72.7	100.0	40.1	32.4	439
Spring 1986	1233	72.6	100.0	40.5	32.9	444
Summer 1986	1232	72.5	100.0	30.6	24.9	336

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.27 Replacement Energy Data for Braidwood 1

Reactor Name:	Braidwood 1	Unit Size (MW):	1,120
Utility:	Commonwealth Edison Co.	Heat Rate (Btu/kWh):	11,173
Power Pool:	8	Variable Fuel Cost (¢/10^6 Btu):	40
NERC Region:	MAIN	Operating Status:	Planned

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	-	-	-	-	-	-
Spring 1985	-	-	-	-	-	-
Summer 1985	-	-	-	-	-	-
Fall 1985	-	-	-	-	-	-
Winter 1985/86	-	-	-	-	-	-
Spring 1986	1037	63.4	66.7	24.2	23.4	399
Summer 1986	1522	62.0	100.0	33.5	22.0	367

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.28 Replacement Energy Data for Byron 1

Reactor Name:	Byron 1	Unit Size (MW):	1,120
Utility:	Commonwealth Edison Co.	Heat Rate (Btu/kWh):	11,173
Power Pool:	8	Variable Fuel Cost (¢/10^6 Btu):	40
NERC Region:	MAIN	Operating Status:	Planned

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	-	-	-	-	-	
Winter 1984/85	1190	72.8	66.7	43.3	36.4	711
Spring 1985	1698	69.2	100.0	54.9	32.3	602
Summer 1985	1610	65.6	100.0	43.7	27.1	478
Fall 1985	1743	71.1	100.0	54.8	31.4	601
Winter 1985/86	1774	72.3	100.0	58.2	32.8	638
Spring 1986	1717	70.0	100.0	45.2	26.3	495
Summer 1986	1638	66.8	100.0	33.5	20.4	367

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.29 Replacement Energy Data for Byron 2

Reactor Name:	Byron 2	Unit Size (MW):	1,120
Utility:	Commonwealth Edison Co.	Heat Rate (Btu/kWh):	11,173
Power Pool:	8	Variable Fuel Cost (¢/10^6 Btu):	40
NERC Region:	MAIN	Operating Status:	Planned

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	-	-	-	-	-	-
Spring 1985	-	-	-	-	-	-
Summer 1985	-	-	-	-	-	-
Fall 1985	-	-	-	-	-	-
Winter 1985/86	-	-	-	-	-	-
Spring 1986	950	58.1	66.7	24.2	25.5	399
Summer 1986	1411	57.5	100.0	33.5	23.7	367

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.30 Replacement Energy Data for Callaway 1

Reactor Name:	Callaway 1	Unit Size (MW):	1,188
Utility:	Union Electric Co.	Heat Rate (Btu/kWh):	11,173
Power Pool:	9-10	Variable Fuel Cost (¢/10^6 Btu):	40
NERC Region:	MAIN	Operating Status:	Planned

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	1259	72.6	66.7	21.9	17.4	361
Spring 1985	1885	72.5	100.0	33.2	17.6	364
Summer 1985	1881	72.3	100.0	29.3	15.6	321
Fall 1985	1882	72.4	100.0	29.7	15.8	325
Winter 1985/86	1889	72.6	100.0	35.2	18.7	386
Spring 1986	1887	72.5	100.0	35.8	19.0	392
Summer 1986	1884	72.4	100.0	29.6	15.7	324

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service; in undiscounted 1984 dollars.

TABLE 4.31 Replacement Energy Data for Dresden 2

Reactor Name:	Dresden 2	Unit Size (MW):	772
Utility:	Commonwealth Edison Co.	Heat Rate (Btu/kWh):	11,221
Power Pool:	8	Variable Fuel Cost (¢/10^6 Btu):	39
NERC Region:	MAIN	Operating Status:	In Service

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1229	72.7	100.0	41.7	33.9	457
Winter 1984/85	1231	72.8	100.0	42.6	34.6	467
Spring 1985	1227	72.6	100.0	37.5	30.5	411
Summer 1985	1222	72.3	100.0	29.9	24.4	327
Fall 1985	1227	72.6	100.0	37.6	30.6	412
Winter 1985/86	1228	72.6	100.0	40.0	32.6	438
Spring 1986	1226	72.5	100.0	30.7	25.0	336
Summer 1986	1221	72.2	100.0	22.6	18.5	248

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.32 Replacement Energy Data for Dresden 3

Reactor Name:	Dresden 3	Unit Size (MW):	773
Utility:	Commonwealth Edison Co.	Heat Rate (Btu/kWh):	11,221
Power Pool:	8	Variable Fuel Cost (¢/10^6 Btu):	39
NERC Region:	MAIN	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1232	72.7	100.0	41.4	33.7	454
Winter 1984/85	1233	72.8	100.0	42.6	34.6	467
Spring 1985	1228	72.5	100.0	37.5	30.6	411
Summer 1985	1224	72.3	100.0	29.9	24.4	328
Fall 1985	1227	72.5	100.0	37.7	30.7	413
Winter 1985/86	1229	72.6	100.0	39.9	32.4	437
Spring 1986	1227	72.5	100.0	30.8	25.1	337
Summer 1986	1223	72.2	100.0	22.7	18.5	248

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.33 Replacement Energy Data for Kewaunee 1

Reactor Name:	Kewaunee 1	Unit Size (MW):	503
Utility:	Wisconsin Public Service Corp. (Major Owner)	Heat Rate (Btu/kWh):	10,969
		Variable Fuel Cost (¢/10^6 Btu):	88
Power Pool:	11	Operating Status:	In Service
NERC Region:	MAIN		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	796	72.3	100.0	9.3	11.7	102
Winter 1984/85	795	72.2	100.0	8.7	10.9	95
Spring 1985	795	72.2	100.0	8.2	10.3	90
Summer 1985	794	72.1	100.0	7.7	9.7	84
Fall 1985	795	72.2	100.0	8.3	10.5	91
Winter 1985/86	796	72.3	100.0	8.5	10.7	93
Spring 1986	796	72.3	100.0	8.3	10.4	91
Summer 1986	795	72.2	100.0	7.6	9.5	83

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.34 Replacement Energy Data for LaSalle 1

Reactor Name:	LaSalle 1	Unit Size (MW):	1,078
Utility:	Commonwealth Edison Co.	Heat Rate (Btu/kWh):	11,173
Power Pool:	8	Variable Fuel Cost (¢/10^6 Btu):	21
NERC Region:	MAIN	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1716	72.7	100.0	62.0	36.1	680
Winter 1984/85	1720	72.8	100.0	63.6	37.0	697
Spring 1985	1712	72.5	100.0	56.4	33.0	619
Summer 1985	1708	72.3	100.0	45.7	26.8	501
Fall 1985	1715	72.6	100.0	56.4	32.9	618
Winter 1985/86	1719	72.8	100.0	59.7	34.7	654
Spring 1986	1714	72.6	100.0	47.1	27.5	516
Summer 1986	1706	72.3	100.0	35.9	21.0	393

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.35 Replacement Energy Data for LaSalle 2

Reactor Name:	LaSalle 2	Unit Size (MW):	1,078
Utility:	Commonwealth Edison Co.	Heat Rate (Btu/kWh):	11,173
Power Pool:	8	Variable Fuel Cost (¢/10^6 Btu):	21
NERC Region:	MAIN	Operating Status:	In Service

Season and Year	Seasonal Operating Statistics[a] Generation to be Replaced (10^6 kWh)	Capacity Factor (%)	% of Season in Service	Seasonal Production-Cost Increase Due to Short-Term Shutdown[b] Total ($\$10^6$)	Average per kWh Replaced (mills/kWh)	Average per Day ($\$10^3$/d)
Fall 1984	1717	72.7	100.0	62.1	36.2	681
Winter 1984/85	1719	72.8	100.0	63.6	37.0	697
Spring 1985	1709	72.4	100.0	56.4	33.0	618
Summer 1985	1707	72.3	100.0	45.7	26.8	501
Fall 1985	1713	72.6	100.0	56.4	32.9	618
Winter 1985/86	1715	72.7	100.0	59.7	34.8	654
Spring 1986	1710	72.4	100.0	47.0	27.5	515
Summer 1986	1706	72.3	100.0	35.9	21.0	393

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.36 Replacement Energy Data for Point Beach 1

Reactor Name:	Point Beach 1	Unit Size (MW):	495
Utility:	Wisconsin Electric Power Co.	Heat Rate (Btu/kWh):	10,745
		Variable Fuel Cost (¢/10^6 Btu):	61
Power Pool:	11	Operating Status:	In Service
NERC Region:	MAIN		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	784	72.3	100.0	11.6	14.8	127
Winter 1984/85	784	72.3	100.0	11.0	14.0	120
Spring 1985	783	72.2	100.0	10.5	13.4	115
Summer 1985	783	72.2	100.0	10.0	12.8	110
Fall 1985	783	72.3	100.0	10.6	13.5	116
Winter 1985/86	785	72.4	100.0	10.8	13.7	118
Spring 1986	784	72.3	100.0	10.6	13.5	116
Summer 1986	783	72.2	100.0	9.9	12.6	108

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.37 Replacement Energy Data for Point Beach 2

Reactor Name:	Point Beach 2	Unit Size (MW):	495
Utility:	Wisconsin Electric Power Co.	Heat Rate (Btu/kWh):	10,745
		Variable Fuel Cost (¢/10^6 Btu):	61
Power Pool:	11	Operating Status:	In Service
NERC Region:	MAIN		

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	783	72.3	100.0	11.6	14.8	127
Winter 1984/85	784	72.3	100.0	11.0	14.0	120
Spring 1985	783	72.2	100.0	10.5	13.4	115
Summer 1985	783	72.2	100.0	10.0	12.8	110
Fall 1985	783	72.3	100.0	10.6	13.5	116
Winter 1985/86	784	72.3	100.0	10.8	13.7	118
Spring 1986	783	72.3	100.0	10.6	13.5	116
Summer 1986	783	72.2	100.0	9.9	12.6	108

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.38 Replacement Energy Data for Quad-Cities 1

Reactor Name:	Quad-Cities 1	Unit Size (MW):	769
Utility:	Commonwealth Edison Co. (Major Owner)	Heat Rate (Btu/kWh):	11,443
		Variable Fuel Cost (¢/10^6 Btu):	45
Power Pool:	8 (75%), 12 (25%)	Operating Status:	In Service
NERC Region:	MAIN (75%), MAPP (25%)		

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1214	72.1	100.0	32.8	27.0	359
Winter 1984/85	1218	72.3	100.0	34.1	28.0	374
Spring 1985	1190	70.7	100.0	32.5	27.3	356
Summer 1985	1093	64.9	100.0	23.8	21.8	261
Fall 1985	1173	69.7	100.0	30.8	26.3	338
Winter 1985/86	1214	72.1	100.0	32.6	26.9	357
Spring 1986	1075	63.8	100.0	25.3	23.5	277
Summer 1986	966	57.4	100.0	18.3	18.9	201

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.39 Replacement Energy Data for Quad-Cities 2

Reactor Name:	Quad-Cities 2	Unit Size (MW):	769
Utility:	Commonwealth Edison Co. (Major Owner)	Heat Rate (Btu/kWh):	11,443
		Variable Fuel Cost (¢/10^6 Btu):	45
Power Pool:	8 (75%), 12 (25%)	Operating Status:	In Service
NERC Region:	MAIN (75%), MAPP (25%)		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1198	71.1	100.0	32.8	27.4	359
Winter 1984/85	1205	71.5	100.0	34.0	28.2	373
Spring 1985	1179	70.0	100.0	32.5	27.6	356
Summer 1985	1065	63.2	100.0	23.8	22.3	261
Fall 1985	1152	68.4	100.0	30.8	26.7	338
Winter 1985/86	1195	71.0	100.0	32.5	27.2	356
Spring 1986	1013	60.2	100.0	25.0	24.7	274
Summer 1986	914	54.3	100.0	18.3	20.0	201

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.40 Replacement Energy Data for Zion 1

Reactor Name:	Zion 1	Unit Size (MW):	1,040
Utility:	Commonwealth Edison Co.	Heat Rate (Btu/kWh):	11,173
Power Pool:	8	Variable Fuel Cost (¢/10^6 Btu):	40
NERC Region:	MAIN	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1654	72.6	100.0	56.2	34.0	616
Winter 1984/85	1657	72.8	100.0	57.7	34.8	632
Spring 1985	1650	72.5	100.0	50.8	30.8	557
Summer 1985	1645	72.2	100.0	40.5	24.6	444
Fall 1985	1652	72.5	100.0	50.6	30.6	555
Winter 1985/86	1654	72.6	100.0	53.9	32.6	590
Spring 1986	1650	72.4	100.0	41.7	25.3	457
Summer 1986	1644	72.2	100.0	30.9	18.8	339

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.41 Replacement Energy Data for Zion 2

Reactor Name:	Zion 2	Unit Size (MW):	1,040
Utility:	Commonwealth Edison Co.	Heat Rate (Btu/kWh):	11,173
Power Pool:	8	Variable Fuel Cost (¢/10^6 Btu):	40
NERC Region:	MAIN	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1654	72.6	100.0	56.2	34.0	616
Winter 1984/85	1651	72.5	100.0	57.7	35.0	632
Spring 1985	1637	71.9	100.0	50.8	31.1	557
Summer 1985	1596	70.1	100.0	40.5	25.4	444
Fall 1985	1650	72.4	100.0	50.6	30.7	555
Winter 1985/86	1653	72.6	100.0	53.9	32.6	590
Spring 1986	1639	71.9	100.0	41.7	25.5	457
Summer 1986	1612	70.8	100.0	30.9	19.2	339

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.42 Replacement Energy Data for Duane Arnold 1

Reactor Name:	Duane Arnold 1	Unit Size (MW):	515
Utility:	Iowa Electric Light and Power Co. (Major Owner)	Heat Rate (Btu/kWh):	11,001
Power Pool:	12	Variable Fuel Cost (¢/10^6 Btu):	42
NERC Region:	MAPP	Operating Status:	In Service

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	815	72.2	100.0	8.2	10.1	90
Winter 1984/85	819	72.6	100.0	8.4	10.2	92
Spring 1985	817	72.4	100.0	11.1	13.6	122
Summer 1985	814	72.2	100.0	6.7	8.2	73
Fall 1985	816	72.3	100.0	10.6	13.0	116
Winter 1985/86	824	73.0	100.0	10.3	12.5	113
Spring 1986	826	73.2	100.0	9.1	11.1	100
Summer 1986	814	72.2	100.0	6.5	8.0	71

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.43 Replacement Energy Data for Cooper 1

Reactor Name:	Cooper 1	Unit Size (MW):	764
Utility:	Nebraska Public Power District	Heat Rate (Btu/kWh):	10,800
		Variable Fuel Cost (¢/10^6 Btu):	61
Power Pool:	12	Operating Status:	In Service
NERC Region:	MAPP		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1209	72.2	100.0	10.4	8.6	114
Winter 1984/85	1214	72.6	100.0	10.1	8.3	111
Spring 1985	1212	72.4	100.0	14.2	11.7	155
Summer 1985	1207	72.1	100.0	7.6	6.3	84
Fall 1985	1210	72.3	100.0	13.2	10.9	144
Winter 1985/86	1220	72.9	100.0	12.5	10.3	137
Spring 1986	1225	73.2	100.0	11.2	9.1	123
Summer 1986	1208	72.2	100.0	7.4	6.1	81

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.44 Replacement Energy Data for Fort Calhoun 1

Reactor Name:	Fort Calhoun 1	Unit Size (MW):	438
Utility:	Omaha Public Power District	Heat Rate (Btu/kWh):	10,969
		Variable Fuel Cost (¢/10^6 Btu):	61
Power Pool:	12	Operating Status:	In Service
NERC Region:	MAPP		

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	693	72.2	100.0	5.5	8.0	60
Winter 1984/85	696	72.6	100.0	5.7	8.2	63
Spring 1985	695	72.4	100.0	8.1	11.6	88
Summer 1985	692	72.2	100.0	4.3	6.2	47
Fall 1985	694	72.3	100.0	7.5	10.8	82
Winter 1985/86	700	72.9	100.0	7.3	10.4	80
Spring 1986	699	72.9	100.0	6.2	8.9	68
Summer 1986	692	72.2	100.0	4.1	5.9	45

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.45 Replacement Energy Data for LaCrosse 5

Reactor Name:	LaCrosse 5	Unit Size (MW):	48
Utility:	Dairyland Power Cooperative	Heat Rate (Btu/kWh):	10,700
		Variable Fuel Cost (¢/10^6 Btu):	52
Power Pool:	12	Operating Status.	In Service
NERC Region:	MAPP		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	76	72.3	100.0	0.7	8.6	7
Winter 1984/85	76	72.7	100.0	0.7	9.6	8
Spring 1985	76	72.5	100.0	1.1	14.8	12
Summer 1985	76	72.2	100.0	0.5	7.2	6
Fall 1985	76	72.4	100.0	0.9	11.7	10
Winter 1985/86	77	73.0	100.0	0.9	11.4	10
Spring 1986	77	73.2	100.0	0.7	9.6	8
Summer 1986	76	72.2	100.0	0.5	6.9	6

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.46 Replacement Energy Data for Monticello 1

Reactor Name:	Monticello 1	Unit Size (MW):	525
Utility:	Northern States Power Co.	Heat Rate (Btu/kWh):	10,804
Power Pool:	12	Variable Fuel Cost (¢/10^6 Btu):	35
NERC Region:	MAPP	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	831	72.2	100.0	9.1	10.9	100
Winter 1984/85	835	72.6	100.0	9.3	11.1	102
Spring 1985	833	72.4	100.0	12.1	14.5	133
Summer 1985	830	72.2	100.0	7.6	9.1	83
Fall 1985	832	72.3	100.0	11.5	13.9	126
Winter 1985/86	840	73.0	100.0	11.3	13.4	123
Spring 1986	842	73.2	100.0	10.1	12.0	110
Summer 1986	830	72.2	100.0	7.4	8.9	81

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.47 Replacement Energy Data for Prairie Island 1

Reactor Name:	Prairie Island 1	Unit Size (MW):	503
Utility:	Northern States Power Co.	Heat Rate (Btu/kWh):	11,099
Power Pool:	12	Variable Fuel Cost (¢/10^6 Btu):	39
NERC Region:	MAPP	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	796	72.2	100.0	8.2	10.4	90
Winter 1984/85	800	72.6	100.0	8.4	10.5	92
Spring 1985	798	72.4	100.0	11.1	14.0	122
Summer 1985	795	72.2	100.0	6.8	8.5	74
Fall 1985	797	72.3	100.0	10.6	13.3	116
Winter 1985/86	805	73.0	100.0	10.3	12.8	113
Spring 1986	807	73.2	100.0	9.2	11.3	100
Summer 1986	795	72.2	100.0	6.6	8.3	72

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.48 Replacement Energy Data for Prairie Island 2

Reactor Name:	Prairie Island 2	Unit Size (MW):	500
Utility:	Northern States Power Co.	Heat Rate (Btu/kWh):	11,099
Power Pool:	12	Variable Fuel Cost (¢/10^6 Btu):	39
NERC Region:	MAPP	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	791	72.2	100.0	8.2	10.4	90
Winter 1984/85	795	72.6	100.0	8.4	10.5	92
Spring 1985	793	72.4	100.0	11.1	14.0	121
Summer 1985	790	72.2	100.0	6.7	8.5	74
Fall 1985	792	72.3	100.0	10.5	13.3	115
Winter 1985/86	800	73.0	100.0	10.2	12.8	112
Spring 1986	802	73.2	100.0	9.1	11.3	100
Summer 1986	790	72.2	100.0	6.5	8.3	72

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.49 Replacement Energy Data for Fitzpatrick 1

Reactor Name:	Fitzpatrick 1	Unit Size (MW):	810
Utility:	New York Power Authority	Heat Rate (Btu/kWh):	10,410
Power Pool:	15	Variable Fuel Cost (¢/10^6 Btu):	27
NERC Region:	NPCC	Operating Status:	In Service

Season and Year	Seasonal Operating Statistics[a] Generation to be Replaced (10^6 kWh)	Capacity Factor (%)	% of Season in Service	Seasonal Production-Cost Increase Due to Short-Term Shutdown[b] Total ($\$10^6$)	Average per kWh Replaced (mills/kWh)	Average per Day ($\$10^3$/d)
Fall 1984	1282	72.3	100.0	56.3	43.9	617
Winter 1984/85	1283	72.4	100.0	56.6	44.1	620
Spring 1985	1282	72.2	100.0	54.8	42.8	601
Summer 1985	1281	72.2	100.0	46.8	36.5	513
Fall 1985	1281	72.2	100.0	51.7	40.3	566
Winter 1985/86	1283	72.3	100.0	56.2	43.8	616
Spring 1986	1281	72.2	100.0	51.5	40.2	564
Summer 1986	1282	72.3	100.0	45.9	35.8	502

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.50 Replacement Energy Data for Ginna 1

Reactor Name:	Ginna 1	Unit Size (MW):	470
Utility:	Rochester Gas and Electric Corp.	Heat Rate (Btu/kWh):	10,973
		Variable Fuel Cost (¢/10^6 Btu):	54
Power Pool:	15	Operating Status:	In Service
NERC Region:	NPCC		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	744	72.3	100.0	30.1	40.5	330
Winter 1984/85	745	72.4	100.0	30.0	40.3	329
Spring 1985	744	72.3	100.0	29.4	39.5	322
Summer 1985	743	72.2	100.0	24.7	33.2	271
Fall 1985	743	72.2	100.0	27.3	36.8	299
Winter 1985/86	744	72.3	100.0	30.2	40.5	331
Spring 1986	743	72.2	100.0	27.4	36.8	300
Summer 1986	744	72.2	100.0	24.1	32.4	264

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.51 Replacement Energy Data for Haddam Neck 1

Reactor Name:	Haddam Neck 1	Unit Size (MW):	569
Utility:	Connecticut Yankee Atomic Power Co.	Heat Rate (Btu/kWh):	10,923
Power Pool:	14	Variable Fuel Cost (¢/10^6 Btu):	62
NERC Region:	NPCC	Operating Status:	In Service

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	922	74.0	100.0	40.0	43.3	438
Winter 1984/85	930	74.6	100.0	40.0	43.1	439
Spring 1985	939	75.4	100.0	43.0	45.8	472
Summer 1985	916	73.5	100.0	37.6	41.1	412
Fall 1985	925	74.3	100.0	39.8	43.0	436
Winter 1985/86	926	74.3	100.0	38.5	41.5	422
Spring 1986	932	74.8	100.0	37.3	40.0	408
Summer 1986	912	73.2	100.0	35.4	38.8	388

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.52 Replacement Energy Data for Indian Point 2

Reactor Name:	Indian Point 2	Unit Size (MW):	864
Utility:	Consolidated Edison Co.	Heat Rate (Btu/kWh):	11,671
Power Pool:	15	Variable Fuel Cost (¢/10^6 Btu):	43
NERC Region:	NPCC	Operating Status:	In Service

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1368	72.3	100.0	57.1	41.8	626
Winter 1984/85	1369	72.3	100.0	57.4	41.9	629
Spring 1985	1367	72.2	100.0	55.5	40.6	608
Summer 1985	1366	72.2	100.0	47.0	34.4	515
Fall 1985	1366	72.2	100.0	52.2	38.2	572
Winter 1985/86	1368	72.3	100.0	56.9	41.6	624
Spring 1986	1367	72.2	100.0	52.0	38.1	570
Summer 1986	1367	72.2	100.0	45.9	33.6	503

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.53 Replacement Energy Data for Indian Point 3

Reactor Name:	Indian Point 3	Unit Size (MW):	965
Utility:	New York Power Authority	Heat Rate (Btu/kWh):	11,671
Power Pool:	15	Variable Fuel Cost (¢/10^6 Btu):	43
NERC Region:	NPCC	Operating Status:	In Service

Season and Year	Seasonal Operating Statistics[a] Generation to be Replaced (10^6 kWh)	Capacity Factor (%)	% of Season in Service	Seasonal Production-Cost Increase Due to Short-Term Shutdown[b] Total ($\$10^6$)	Average per kWh Replaced (mills/kWh)	Average per Day ($\$10^3$/d)
Fall 1984	1528	72.3	100.0	63.9	41.8	700
Winter 1984/85	1529	72.3	100.0	64.4	42.1	705
Spring 1985	1527	72.2	100.0	62.0	40.6	679
Summer 1985	1526	72.2	100.0	52.6	34.5	577
Fall 1985	1526	72.2	100.0	58.6	38.4	642
Winter 1985/86	1528	72.3	100.0	63.8	41.7	699
Spring 1986	1526	72.2	100.0	58.1	38.1	637
Summer 1986	1527	72.3	100.0	51.4	33.7	564

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.54 Replacement Energy Data for Maine Yankee 1

Reactor Name:	Maine Yankee 1	Unit Size (MW):	810
Utility:	Maine Yankee Atomic Power Co.	Heat Rate (Btu/kWh):	11,126
		Variable Fuel Cost (¢/10^6 Btu):	49
Power Pool:	14	Operating Status:	In Service
NERC Region:	NPCC		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1313	74.0	100.0	59.0	44.9	647
Winter 1984/85	1326	74.7	100.0	59.4	44.8	650
Spring 1985	1338	75.4	100.0	64.0	47.8	701
Summer 1985	1304	73.5	100.0	55.5	42.5	608
Fall 1985	1317	74.3	100.0	58.9	44.7	645
Winter 1985/86	1320	74.6	100.0	57.3	43.4	628
Spring 1986	1329	74.9	100.0	56.9	42.8	623
Summer 1986	1300	73.3	100.0	52.6	40.5	577

[a] Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b] For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.55 Replacement Energy Data for Millstone 1

Reactor Name:	Millstone 1	Unit Size (MW):	654
Utility:	Northeast Utilities (Major Owner)	Heat Rate (Btu/kWh):	11,387
		Variable Fuel Cost (¢/10^6 Btu):	52
Power Pool:	14	Operating Status:	In Service
NERC Region:	NPCC		

Season and Year	Seasonal Operating Statistics[a] Generation to be Replaced (10^6 kWh)	Capacity Factor (%)	% of Season in Service	Seasonal Production-Cost Increase Due to Short-Term Shutdown[b] Total ($\$10^6$)	Average per kWh Replaced (mills/kWh)	Average per Day ($\$10^3$/d)
Fall 1984	1061	74.1	100.0	46.9	44.2	514
Winter 1984/85	1070	74.7	100.0	47.0	43.9	515
Spring 1985	1080	75.4	100.0	50.5	46.7	553
Summer 1985	1053	73.5	100.0	44.1	41.9	483
Fall 1985	1065	74.3	100.0	46.7	43.9	512
Winter 1985/86	1066	74.4	100.0	45.3	42.5	496
Spring 1986	1072	74.9	100.0	44.3	41.3	486
Summer 1986	1049	73.3	100.0	41.7	39.7	457

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.56 Replacement Energy Data for Millstone 2

Reactor Name:	Millstone 2	Unit Size (MW):	860
Utility:	Northeast Utilities (Major Owner)	Heat Rate (Btu/kWh):	10,926
		Variable Fuel Cost (¢/10^6 Btu):	60
Power Pool:	14	Operating Status:	In Service
NERC Region:	NPCC		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1394	74.0	100.0	61.1	43.8	670
Winter 1984/85	1405	74.6	100.0	61.5	43.8	674
Spring 1985	1420	75.4	100.0	66.4	46.8	728
Summer 1985	1383	73.4	100.0	57.4	41.5	629
Fall 1985	1398	74.2	100.0	61.0	43.6	668
Winter 1985/86	1400	74.3	100.0	59.4	42.5	651
Spring 1986	1408	74.7	100.0	59.2	42.1	649
Summer 1986	1378	73.2	100.0	54.4	39.5	596

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.57 Replacement Energy Data for Millstone 3

Reactor Name:	Millstone 3	Unit Size (MW):	1,150
Utility:	Northeast Utilities (Major Owner)	Heat Rate (Btu/kWh):	10,926
		Variable Fuel Cost (¢/10^6 Btu):	60
Power Pool:	14	Operating Status:	Planned
NERC Region:	NPCC		

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	-	-	-	-	-	-
Spring 1985	-	-	-	-	-	-
Summer 1985	-	-	-	-	-	-
Fall 1985	-	-	-	-	-	-
Winter 1985/86	-	-	-	-	-	-
Spring 1986	628	74.8	33.3	27.6	44.0	908
Summer 1986	1842	73.1	100.0	73.3	39.8	803

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.58 Replacement Energy Data for Nine Mile Point 1

Reactor Name:	Nine Mile Point 1	Unit Size (MW):	610
Utility:	Niagara Mohawk Power Corp. (Major Owner)	Heat Rate (Btu/kWh):	10,288
		Variable Fuel Cost (¢/10^6 Btu):	69
Power Pool:	15	Operating Status:	In Service
NERC Region:	NPCC		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	966	72.3	100.0	38.2	39.5	418
Winter 1984/85	966	72.3	100.0	38.3	39.6	419
Spring 1985	965	72.3	100.0	37.1	38.4	406
Summer 1985	965	72.2	100.0	31.1	32.2	341
Fall 1985	965	72.2	100.0	34.4	35.7	377
Winter 1985/86	966	72.3	100.0	38.1	39.4	417
Spring 1986	965	72.2	100.0	34.5	35.7	378
Summer 1986	965	72.2	100.0	30.2	31.3	331

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.59 Replacement Energy Data for Pilgrim 1

Reactor Name:	Pilgrim 1	Unit Size (MW):	670
Utility:	Boston Edison Co.	Heat Rate (Btu/kWh):	10,275
Power Pool:	14	Variable Fuel Cost (¢/10^6 Btu):	39
NERC Region:	NPCC	Operating Status:	In Service

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1088	74.2	100.0	50.2	46.1	550
Winter 1984/85	1098	74.8	100.0	50.4	45.9	552
Spring 1985	1107	75.4	100.0	53.9	48.7	591
Summer 1985	1080	73.6	100.0	47.3	43.8	519
Fall 1985	1092	74.4	100.0	50.1	45.9	549
Winter 1985/86	1093	74.5	100.0	48.6	44.4	532
Spring 1986	1101	75.0	100.0	47.7	43.3	523
Summer 1986	1075	73.3	100.0	44.8	41.7	491

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.60 Replacement Energy Data for Seabrook 1

Reactor Name:	Seabrook 1	Unit Size (MW):	1,198
Utility:	Public Service Co. of New Hampshire	Heat Rate (Btu/kWh):	10,725
Power Pool:	14	Variable Fuel Cost (¢/10^6 Btu):	63
NERC Region:	NPCC	Operating Status:	Planned

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	-	-	-	-	-	-
Spring 1985	-	-	-	-	-	-
Summer 1985	-	-	-	-	-	-
Fall 1985	-	-	-	-	-	-
Winter 1985/86	-	-	-	-	-	-
Spring 1986	-	-	-	-	-	-
Summer 1986	640	73.2	33.3	26.0	40.7	856

[a] Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b] For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.61 Replacement Energy Data for Shoreham 1

Reactor Name:	Shoreham 1	Unit Size (MW):	820
Utility:	Long Island Lighting Co.	Heat Rate (Btu/kWh):	11,671
Power Pool:	15	Variable Fuel Cost (¢/10^6 Btu):	43
NERC Region:	NPCC	Operating Status:	Planned

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	-	-	-	-	-	-
Spring 1985	-	-	-	-	-	-
Summer 1985	865	72.2	66.7	29.8	34.5	490
Fall 1985	1296	72.2	100.0	49.5	38.2	543
Winter 1985/86	1299	72.3	100.0	54.0	41.6	592
Spring 1986	1297	72.2	100.0	49.3	38.0	540
Summer 1986	1297	72.2	100.0	43.6	33.6	477

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.62 Replacement Energy Data for Vermont Yankee 1

Reactor Name: Vermont Yankee 1
Utility: Vermont Yankee Nuclear Power Corp.
Power Pool: 14
NERC Region: NPCC

Unit Size (MW): 504
Heat Rate (Btu/kWh): 10,725
Variable Fuel Cost (¢/10^6 Btu): 63
Operating Status: In Service

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	817	74.0	100.0	35.4	43.3	388
Winter 1984/85	824	74.6	100.0	35.4	42.9	388
Spring 1985	832	75.3	100.0	37.9	45.6	416
Summer 1985	811	73.5	100.0	33.3	41.1	365
Fall 1985	820	74.3	100.0	35.2	43.0	386
Winter 1985/86	820	74.3	100.0	33.9	41.3	371
Spring 1986	825	74.8	100.0	32.9	39.9	361
Summer 1986	808	73.2	100.0	31.4	38.8	344

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.63 Replacement Energy Data for Yankee Rowe 1

Reactor Name:	Yankee Rowe 1	Unit Size (MW):	169
Utility:	Yankee Atomic Electric Co.	Heat Rate (Btu/kWh):	14,090
Power Pool:	14	Variable Fuel Cost (¢/10^6 Btu):	42
NERC Region:	NPCC	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	274	74.1	100.0	12.0	43.9	132
Winter 1984/85	276	74.7	100.0	11.9	43.2	131
Spring 1985	279	75.4	100.0	12.8	45.7	140
Summer 1985	272	73.5	100.0	11.4	41.9	125
Fall 1985	275	74.3	100.0	11.9	43.4	131
Winter 1985/86	275	74.4	100.0	11.5	41.6	126
Spring 1986	277	74.9	100.0	11.0	39.6	120
Summer 1986	271	73.2	100.0	10.6	39.2	116

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.64 Replacement Energy Data for Browns Ferry 1

Reactor Name:	Browns Ferry 1	Unit Size (MW):	1,065
Utility:	Tennessee Valley Authority	Heat Rate (Btu/kWh):	10,720
Power Pool:	18	Variable Fuel Cost (¢/10^6 Btu):	30
NERC Region:	SERC	Operating Status:	In Service

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1693	72.6	100.0	27.9	16.5	306
Winter 1984/85	1682	72.1	100.0	26.4	15.7	289
Spring 1985	1682	72.1	100.0	26.7	15.9	292
Summer 1985	1688	72.4	100.0	25.6	15.2	280
Fall 1985	1695	72.7	100.0	27.1	16.0	297
Winter 1985/86	1682	72.1	100.0	25.9	15.4	283
Spring 1986	1682	72.1	100.0	25.7	15.3	281
Summer 1986	1689	72.4	100.0	25.2	14.9	276

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.65 Replacement Energy Data for Browns Ferry 2

Reactor Name:	Browns Ferry 2	Unit Size (MW):	1,065
Utility:	Tennessee Valley Authority	Heat Rate (Btu/kWh):	10,720
Power Pool:	18	Variable Fuel Cost (¢/10^6 Btu):	30
NERC Region:	SERC	Operating Status:	In Service

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1692	72.5	100.0	27.9	16.5	306
Winter 1984/85	1682	72.1	100.0	26.4	15.7	289
Spring 1985	1682	72.1	100.0	26.7	15.9	292
Summer 1985	1686	72.3	100.0	25.6	15.2	280
Fall 1985	1694	72.6	100.0	27.1	16.0	297
Winter 1985/86	1682	72.1	100.0	25.9	15.4	283
Spring 1986	1682	72.1	100.0	25.7	15.3	281
Summer 1986	1689	72.4	100.0	25.2	14.9	276

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.66 Replacement Energy Data for Browns Ferry 3

Reactor Name:	Browns Ferry 3	Unit Size (MW):	1,065
Utility:	Tennessee Valley Authority	Heat Rate (Btu/kWh):	10,720
Power Pool:	18	Variable Fuel Cost (¢/10^6 Btu):	30
NERC Region:	SERC	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1691	72.5	100.0	27.9	16.5	306
Winter 1984/85	1682	72.1	100.0	26.4	15.7	289
Spring 1985	1682	72.1	100.0	26.7	15.9	292
Summer 1985	1686	72.3	100.0	25.6	15.2	280
Fall 1985	1694	72.6	100.0	27.1	16.0	297
Winter 1985/86	1682	72.1	100.0	25.9	15.4	283
Spring 1986	1682	72.1	100.0	25.7	15.3	281
Summer 1986	1688	72.4	100.0	25.2	14.9	276

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.67 Replacement Energy Data for Brunswick 1

Reactor Name:	Brunswick 1	Unit Size (MW):	790
Utility:	Carolina Power and Light Co.	Heat Rate (Btu/kWh):	11,166
		Variable Fuel Cost (¢/10^6 Btu):	42
Power Pool:	19	Operating Status:	In Service
NERC Region:	SERC		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1279	73.9	100.0	35.5	27.7	389
Winter 1984/85	1270	73.4	100.0	25.8	20.3	283
Spring 1985	1284	74.2	100.0	36.2	28.2	397
Summer 1985	1271	73.4	100.0	27.7	21.8	304
Fall 1985	1282	74.1	100.0	35.9	28.0	394
Winter 1985/86	1264	73.0	100.0	24.4	19.3	267
Spring 1986	1280	74.0	100.0	30.5	23.9	335
Summer 1986	1268	73.3	100.0	25.5	20.1	280

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.68 Replacement Energy Data for Brunswick 2

Reactor Name:	Brunswick 2	Unit Size (MW):	790
Utility:	Carolina Power and Light Co.	Heat Rate (Btu/kWh):	11,166
		Variable Fuel Cost (¢/10^6 Btu):	42
Power Pool:	19	Operating Status:	In Service
NERC Region:	SERC		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1279	73.9	100.0	35.5	27.7	389
Winter 1984/85	1271	73.4	100.0	25.8	20.3	283
Spring 1985	1284	74.2	100.0	36.2	28.2	397
Summer 1985	1271	73.5	100.0	27.7	21.8	304
Fall 1985	1282	74.1	100.0	35.9	28.0	394
Winter 1985/86	1264	73.1	100.0	24.4	19.3	267
Spring 1986	1280	74.0	100.0	30.5	23.9	335
Summer 1986	1268	73.3	100.0	25.5	20.1	280

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.69 Replacement Energy Data for Catawba 1

Reactor Name:	Catawba 1	Unit Size (MW):	1,145
Utility:	Duke Power Co.	Heat Rate (Btu/kWh):	10,641
Power Pool:	19	Variable Fuel Cost (¢/10^6 Btu):	39
NERC Region:	SERC	Operating Status:	Planned

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	-	-	-	-	-	-
Spring 1985	-	-	-	-	-	-
Summer 1985	1843	73.5	100.0	42.0	22.8	460
Fall 1985	1859	74.1	100.0	52.4	28.2	574
Winter 1985/86	1838	73.3	100.0	36.6	19.9	401
Spring 1986	1857	74.1	100.0	46.7	25.2	512
Summer 1986	1839	73.3	100.0	38.5	21.0	422

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.70 Replacement Energy Data for Crystal River 3

Reactor Name:	Crystal River 3	Unit Size (MW):	811
Utility:	Florida Power Corp. (Major Owner)	Heat Rate (Btu/kWh):	10,551
		Variable Fuel Cost (¢/10^6 Btu):	47
Power Pool:	16	Operating Status:	In Service
NERC Region:	SERC		

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1299	73.1	100.0	48.0	37.0	526
Winter 1984/85	1284	72.3	100.0	39.9	31.1	437
Spring 1985	1290	72.7	100.0	44.5	34.5	488
Summer 1985	1286	72.4	100.0	44.4	34.5	487
Fall 1985	1288	72.5	100.0	45.2	35.1	496
Winter 1985/86	1285	72.3	100.0	39.5	30.8	433
Spring 1986	1296	73.0	100.0	47.3	36.5	518
Summer 1986	1295	72.9	100.0	44.9	34.6	492

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.71 Replacement Energy Data for Farley 1

Reactor Name:	Farley 1	Unit Size (MW):	804
Utility:	Alabama Power Co.	Heat Rate (Btu/kWh):	11,388
Power Pool:	17	Variable Fuel Cost (¢/10^6 Btu):	44
NERC Region:	SERC	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1298	73.7	100.0	23.5	18.1	257
Winter 1984/85	1306	74.2	100.0	27.0	20.7	296
Spring 1985	1332	75.7	100.0	23.4	17.6	257
Summer 1985	1310	74.4	100.0	25.6	19.6	281
Fall 1985	1326	75.3	100.0	51.0	38.5	559
Winter 1985/86	1326	75.3	100.0	28.0	21.1	306
Spring 1986	1337	75.9	100.0	51.9	38.8	568
Summer 1986	1315	74.7	100.0	27.0	20.5	296

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.72 Replacement Energy Data for Farley 2

Reactor Name:	Farley 2	Unit Size (MW):	814
Utility:	Alabama Power Co.	Heat Rate (Btu/kWh):	11,388
Power Pool:	17	Variable Fuel Cost (¢/10^6 Btu):	44
NERC Region:	SERC	Operating Status:	In Service

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1315	73.7	100.0	23.8	18.1	261
Winter 1984/85	1322	74.2	100.0	27.0	20.4	295
Spring 1985	1349	75.7	100.0	25.1	18.6	275
Summer 1985	1326	74.4	100.0	25.7	19.4	282
Fall 1985	1342	75.3	100.0	51.8	38.6	568
Winter 1985/86	1342	75.3	100.0	28.7	21.4	314
Spring 1986	1354	75.9	100.0	52.5	38.8	575
Summer 1986	1331	74.7	100.0	27.3	20.5	300

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.73 Replacement Energy Data for Harris 1

Reactor Name:	Harris 1	Unit Size (MW):	900
Utility:	Carolina Power and Light Co. (Major Owner)	Heat Rate (Btu/kWh):	10,641
		Variable Fuel Cost (¢/10^6 Btu):	39
Power Pool:	19	Operating Status:	Planned
NERC Region:	SERC		

Season and Year	Seasonal Operating Statistics[a]: Generation to be Replaced (10^6 kWh)	Seasonal Operating Statistics[a]: Capacity Factor (%)	Seasonal Operating Statistics[a]: % of Season in Service	Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]: Total ($\$10^6$)	Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]: Average per kWh Replaced (mills/kWh)	Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]: Average per Day ($\$10^3$/d)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	-	-	-	-	-	-
Spring 1985	-	-	-	-	-	-
Summer 1985	-	-	-	-	-	-
Fall 1985	-	-	-	-	-	-
Winter 1985/86	-	-	-	-	-	-
Spring 1986	1459	74.0	100.0	35.7	24.5	391
Summer 1986	1446	73.3	100.0	30.0	20.7	329

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.74 Replacement Energy Data for Hatch 1

Reactor Name:	Hatch 1	Unit Size (MW):	764
Utility:	Georgia Power Co.	Heat Rate (Btu/kWh):	10,997
Power Pool:	17	Variable Fuel Cost (¢/10^6 Btu):	34
NERC Region:	SERC	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1235	73.8	100.0	23.9	19.4	262
Winter 1984/85	1242	74.2	100.0	28.2	22.7	309
Spring 1985	1267	75.7	100.0	24.2	19.1	265
Summer 1985	1246	74.5	100.0	25.9	20.8	284
Fall 1985	1261	75.3	100.0	50.0	39.7	548
Winter 1985/86	1261	75.4	100.0	27.4	21.7	300
Spring 1986	1271	76.0	100.0	50.6	39.8	555
Summer 1986	1250	74.7	100.0	27.2	21.8	298

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.75 Replacement Energy Data for Hatch 2

Reactor Name:	Hatch 2	Unit Size (MW):	771
Utility:	Georgia Power Co. (Major Owner)	Heat Rate (Btu/kWh):	10,997
		Variable Fuel Cost (¢/10^6 Btu):	34
Power Pool:	17	Operating Status:	In Service
NERC Region:	SERC		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1246	73.8	100.0	24.1	19.4	265
Winter 1984/85	1253	74.2	100.0	28.4	22.7	312
Spring 1985	1278	75.7	100.0	27.1	21.2	297
Summer 1985	1257	74.4	100.0	26.0	20.7	285
Fall 1985	1272	75.3	100.0	50.6	39.8	555
Winter 1985/86	1272	75.4	100.0	28.2	22.2	309
Spring 1986	1283	76.0	100.0	51.1	39.8	560
Summer 1986	1262	74.7	100.0	27.5	21.8	301

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.76 Replacement Energy Data for McGuire 1

Reactor Name:	McGuire 1	Unit Size (MW):	1,180
Utility:	Duke Power Co.	Heat Rate (Btu/kWh):	10,641
Power Pool:	19	Variable Fuel Cost (¢/10^6 Btu):	39
NERC Region:	SERC	Operating Status:	In Service

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1913	74.0	100.0	54.6	28.6	598
Winter 1984/85	1900	73.5	100.0	41.3	21.7	452
Spring 1985	1919	74.3	100.0	57.0	29.7	624
Summer 1985	1901	73.6	100.0	43.4	22.8	475
Fall 1985	1917	74.2	100.0	54.1	28.2	593
Winter 1985/86	1896	73.4	100.0	37.7	19.9	414
Spring 1986	1914	74.1	100.0	48.2	25.2	528
Summer 1986	1897	73.4	100.0	39.8	21.0	436

[a] Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b] For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.77 Replacement Energy Data for McGuire 2

Reactor Name:	McGuire 2	Unit Size (MW):	1,180
Utility:	Duke Power Co.	Heat Rate (Btu/kWh):	10,641
Power Pool:	19	Variable Fuel Cost (¢/10^6 Btu):	39
NERC Region:	SERC	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1911	73.9	100.0	54.6	28.6	599
Winter 1984/85	1899	73.5	100.0	41.2	21.7	452
Spring 1985	1919	74.3	100.0	57.0	29.7	624
Summer 1985	1900	73.5	100.0	43.4	22.8	475
Fall 1985	1917	74.2	100.0	54.1	28.2	593
Winter 1985/86	1895	73.3	100.0	37.7	19.9	414
Spring 1986	1914	74.1	100.0	48.2	25.2	528
Summer 1986	1896	73.4	100.0	39.8	21.0	436

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.78 Replacement Energy Data for North Anna 1

Reactor Name:	North Anna 1	Unit Size (MW):	877
Utility:	Virginia Electric and Power Co.	Heat Rate (Btu/kWh):	11,062
		Variable Fuel Cost (¢/10^6 Btu):	38
Power Pool:	19	Operating Status:	In Service
NERC Region:	SERC		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1420	73.9	100.0	39.9	28.1	438
Winter 1984/85	1411	73.5	100.0	29.7	21.0	325
Spring 1985	1426	74.3	100.0	41.3	28.9	452
Summer 1985	1412	73.5	100.0	31.6	22.4	346
Fall 1985	1424	74.1	100.0	40.7	28.6	446
Winter 1985/86	1406	73.2	100.0	27.7	19.7	304
Spring 1986	1422	74.0	100.0	34.9	24.5	382
Summer 1986	1409	73.3	100.0	29.1	20.7	319

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.79 **Replacement Energy Data for North Anna 2**

Reactor Name:	North Anna 2	Unit Size (MW):	890
Utility:	Virginia Electric and Power Co.	Heat Rate (Btu/kWh):	11,062
Power Pool:	19	Variable Fuel Cost (¢/10^6 Btu):	38
NERC Region:	SERC	Operating Status:	In Service

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1442	74.0	100.0	40.6	28.1	445
Winter 1984/85	1432	73.5	100.0	30.2	21.1	331
Spring 1985	1448	74.3	100.0	41.9	29.0	459
Summer 1985	1432	73.5	100.0	32.1	22.4	352
Fall 1985	1445	74.1	100.0	41.3	28.6	453
Winter 1985/86	1426	73.1	100.0	28.2	19.8	309
Spring 1986	1443	74.1	100.0	35.2	24.4	386
Summer 1986	1429	73.3	100.0	29.5	20.7	324

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.80 Replacement Energy Data for Oconee 1

Reactor Name:	Oconee 1	Unit Size (MW):	860
Utility:	Duke Power Co.	Heat Rate (Btu/kWh):	10,460
Power Pool:	19	Variable Fuel Cost (¢/10^6 Btu):	45
NERC Region:	SERC	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1391	73.9	100.0	38.4	27.6	421
Winter 1984/85	1382	73.4	100.0	28.3	20.5	311
Spring 1985	1397	74.2	100.0	39.7	28.4	435
Summer 1985	1383	73.4	100.0	30.2	21.9	331
Fall 1985	1395	74.1	100.0	39.1	28.1	429
Winter 1985/86	1375	73.0	100.0	26.5	19.3	290
Spring 1986	1393	74.0	100.0	33.4	24.0	366
Summer 1986	1380	73.3	100.0	27.8	20.2	305

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.81 Replacement Energy Data for Oconee 2

Reactor Name:	Oconee 2	Unit Size (MW):	860
Utility:	Duke Power Co.	Heat Rate (Btu/kWh):	10,460
Power Pool:	19	Variable Fuel Cost (¢/10^6 Btu):	45
NERC Region:	SERC	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1391	73.8	100.0	38.4	27.6	421
Winter 1984/85	1380	73.3	100.0	28.3	20.5	311
Spring 1985	1397	74.2	100.0	39.7	28.4	435
Summer 1985	1382	73.4	100.0	30.2	21.9	331
Fall 1985	1395	74.1	100.0	39.1	28.1	429
Winter 1985/86	1375	73.0	100.0	26.5	19.3	290
Spring 1986	1393	74.0	100.0	33.4	24.0	366
Summer 1986	1380	73.3	100.0	27.8	20.2	305

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.82 Replacement Energy Data for Oconee 3

Reactor Name:	Oconee 3	Unit Size (MW):	860
Utility:	Duke Power Co.	Heat Rate (Btu/kWh):	10,460
Power Pool:	19	Variable Fuel Cost (¢/10^6 Btu):	45
NERC Region:	SERC	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1391	73.8	100.0	38.4	27.6	421
Winter 1984/85	1378	73.2	100.0	28.3	20.6	311
Spring 1985	1397	74.2	100.0	39.7	28.4	435
Summer 1985	1382	73.4	100.0	30.2	21.9	331
Fall 1985	1395	74.1	100.0	[illegible]9.1	28.1	429
Winter 1985/86	1375	73.0	100.0	[illegible].5	19.3	290
Spring 1986	1393	74.0	100.0	33.4	24.0	366
Summer 1986	1379	73.2	100.0	27.8	20.2	305

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.83 Replacement Energy Data for Robinson 2

Reactor Name:	Robinson 2	Unit Size (MW):	665
Utility:	Carolina Power and Light Co.	Heat Rate (Btu/kWh):	11,624
Power Pool:	19	Variable Fuel Cost (¢/10^6 Btu):	26
NERC Region:	SERC	Operating Status:	In Service

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1076	73.9	100.0	31.6	29.3	346
Winter 1984/85	1071	73.6	100.0	23.2	21.7	254
Spring 1985	1083	74.3	100.0	31.8	29.3	348
Summer 1985	1072	73.6	100.0	25.0	23.4	275
Fall 1985	1079	74.1	100.0	32.0	29.6	350
Winter 1985/86	1069	73.4	100.0	22.1	20.7	242
Spring 1986	1077	74.0	100.0	27.4	25.4	300
Summer 1986	1070	73.5	100.0	23.1	21.6	253

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.84 Replacement Energy Data for Sequoyah 1

Reactor Name:	Sequoyah 1	Unit Size (MW):	1,148
Utility:	Tennessee Valley Authority	Heat Rate (Btu/kWh):	10,620
Power Pool:	18	Variable Fuel Cost (¢/10^6 Btu):	33
NERC Region:	SERC	Operating Status:	In Service

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1822	72.5	100.0	29.6	16.3	325
Winter 1984/85	1812	72.1	100.0	27.9	15.4	306
Spring 1985	1813	72.1	100.0	28.3	15.6	310
Summer 1985	1814	72.1	100.0	27.1	14.9	297
Fall 1985	1825	72.6	100.0	28.8	15.8	316
Winter 1985/86	1813	72.1	100.0	27.4	15.1	300
Spring 1986	1813	72.1	100.0	27.2	15.0	298
Summer 1986	1819	72.4	100.0	26.7	14.7	293

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.85 Replacement Energy Data for Sequoyah 2

Reactor Name:	Sequoyah 2	Unit Size (MW):	1,148
Utility:	Tennessee Valley Authority	Heat Rate (Btu/kWh):	10,620
Power Pool:	18	Variable Fuel Cost (¢/10^6 Btu):	33
NERC Region:	SERC	Operating Status:	In Service

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1822	72.5	100.0	29.6	16.3	325
Winter 1984/85	1812	72.1	100.0	27.9	15.4	306
Spring 1985	1813	72.1	100.0	28.3	15.6	310
Summer 1985	1812	72.1	100.0	27.1	14.9	297
Fall 1985	1824	72.6	100.0	28.8	15.8	316
Winter 1985/86	1813	72.1	100.0	27.4	15.1	300
Spring 1986	1813	72.1	100.0	27.2	15.0	298
Summer 1986	1819	72.3	100.0	26.7	14.7	293

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.86 Replacement Energy Data for St. Lucie 1

Reactor Name:	St. Lucie 1	Unit Size (MW):	822
Utility:	Florida Power and Light Co.	Heat Rate (Btu/kWh):	10,968
Power Pool:	16	Variable Fuel Cost (¢/10^6 Btu):	73
NERC Region:	SFRC	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1316	73.1	100.0	44.7	33.9	489
Winter 1984/85	1301	72.3	100.0	36.5	28.0	400
Spring 1985	1308	72.7	100.0	41.2	31.5	451
Summer 1985	1304	72.4	100.0	41.1	31.5	450
Fall 1985	1305	72.5	100.0	41.9	32.1	459
Winter 1985/86	1302	72.3	100.0	36.1	27.8	396
Spring 1986	1313	73.0	100.0	43.9	33.4	481
Summer 1986	1311	72.8	100.0	41.5	31.6	455

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.87 Replacement Energy Data for St. Lucie 2

Reactor Name:	St. Lucie 2	Unit Size (MW):	786
Utility:	Florida Power and Light Co. (Major Owner)	Heat Rate (Btu/kWh):	10,968
		Variable Fuel Cost (¢/10^6 Btu):	73
Power Pool:	16	Operating Status:	In Service
NERC Region:	SERC		

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1258	73.1	100.0	42.7	33.9	468
Winter 1984/85	1233	71.6	100.0	34.9	28.3	382
Spring 1985	1250	72.6	100.0	39.4	31.5	432
Summer 1985	1247	72.4	100.0	39.3	31.5	431
Fall 1985	1248	72.5	100.0	40.0	32.1	439
Winter 1985/86	1242	72.2	100.0	34.5	27.8	378
Spring 1986	1256	73.0	100.0	42.0	33.4	460
Summer 1986	1254	72.8	100.0	39.6	31.6	434

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.88 Replacement Energy Data for Surry 1

Reactor Name:	Surry 1	Unit Size (MW):	775
Utility:	Virginia Electric and Power Co.	Heat Rate (Btu/kWh):	11,282
Power Pool:	19	Variable Fuel Cost (¢/10^6 Btu):	50
NERC Region:	SERC	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1253	73.8	100.0	33.6	26.8	368
Winter 1984/85	1242	73.2	100.0	24.1	19.4	264
Spring 1985	1258	74.1	100.0	34.3	27.2	376
Summer 1985	1245	73.3	100.0	26.0	20.9	285
Fall 1985	1257	74.0	100.0	34.1	27.1	373
Winter 1985/86	1239	73.0	100.0	22.7	18.3	249
Spring 1986	1255	74.0	100.0	28.8	22.9	315
Summer 1986	1241	73.1	100.0	23.9	19.2	262

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.89 Replacement Energy Data for Surry 2

Reactor Name:	Surry 2	Unit Size (MW):	775
Utility:	Virginia Electric and Power Co.	Heat Rate (Btu/kWh):	11,282
Power Pool:	19	Variable Fuel Cost (¢/10^6 Btu):	50
NERC Region:	SERC	Operating Status:	In Service

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1253	73.8	100.0	33.6	26.8	368
Winter 1984/85	1241	73.1	100.0	24.1	19.4	264
Spring 1985	1258	74.1	100.0	34.3	27.2	376
Summer 1985	1243	73.2	100.0	26.0	20.9	285
Fall 1985	1256	74.0	100.0	34.1	27.1	373
Winter 1985/86	1238	73.0	100.0	22.7	18.3	249
Spring 1986	1255	73.9	100.0	28.8	22.9	315
Summer 1986	1240	73.1	100.0	23.9	19.3	262

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.90 Replacement Energy Data for Turkey Point 3

Reactor Name:	Turkey Point 3	Unit Size (MW):	666
Utility:	Florida Power and Light Co.	Heat Rate (Btu/kWh):	11,173
Power Pool:	16	Variable Fuel Cost (¢/10^6 Btu):	19
NERC Region:	SERC	Operating Status:	In Service

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1068	73.2	100.0	42.4	39.7	464
Winter 1984/85	1055	72.4	100.0	35.7	33.8	391
Spring 1985	1061	72.8	100.0	39.5	37.2	432
Summer 1985	1058	72.5	100.0	39.7	37.5	435
Fall 1985	1059	72.6	100.0	40.2	37.9	440
Winter 1985/86	1056	72.4	100.0	35.4	33.5	388
Spring 1986	1065	73.0	100.0	41.7	39.2	457
Summer 1986	1064	73.0	100.0	39.8	37.4	436

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.91 Replacement Energy Data for Turkey Point 4

Reactor Name:	Turkey Point 4	Unit Size (MW):	666
Utility:	Florida Power and Light Co.	Heat Rate (Btu/kWh):	11,173
Power Pool:	16	Variable Fuel Cost (¢/10^6 Btu):	19
NERC Region:	SERC	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1068	73.2	100.0	42.4	39.7	464
Winter 1984/85	1055	72.4	100.0	35.7	33.8	391
Spring 1985	1061	72.8	100.0	39.5	37.2	432
Summer 1985	1057	72.5	100.0	39.7	37.5	435
Fall 1985	1059	72.6	100.0	40.2	37.9	440
Winter 1985/86	1056	72.4	100.0	35.4	33.5	388
Spring 1986	1065	73.0	100.0	41.7	39.2	457
Summer 1986	1064	73.0	100.0	39.8	37.4	436

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.92 Replacement Energy Data for V.C. Summer 1

Reactor Name:	V.C. Summer 1	Unit Size (MW):	900
Utility:	South Carolina Electric and Gas Co.	Heat Rate (Btu/kWh):	10,641
		Variable Fuel Cost (¢/10^6 Btu):	39
Power Pool:	19	Operating Status:	In Service
NERC Region:	SERC		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1459	74.0	100.0	41.1	28.2	451
Winter 1984/85	1449	73.5	100.0	30.6	21.1	336
Spring 1985	1464	74.3	100.0	42.5	29.0	466
Summer 1985	1449	73.5	100.0	32.6	22.5	357
Fall 1985	1462	74.2	100.0	41.9	28.6	459
Winter 1985/86	1446	73.4	100.0	28.6	19.8	313
Spring 1986	[illegible]	74.1	100.0	35.7	24.4	391
Summer 1986	[illegible]	73.4	100.0	30.0	20.7	328

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.93 Replacement Energy Data for Watts Bar 1

Reactor Name:	Watts Bar 1	Unit Size (MW):	1,165
Utility:	Tennessee Valley Authority	Heat Rate (Btu/kWh):	10,620
Power Pool:	18	Variable Fuel Cost (¢/10^6 Btu):	33
NERC Region:	SERC	Operating Status:	Planned

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	613	72.1	33.3	9.9	16.1	324
Winter 1984/85	1839	72.1	100.0	28.3	15.4	311
Spring 1985	1840	72.1	100.0	28.7	15.6	314
Summer 1985	1837	72.0	100.0	27.5	15.0	301
Fall 1985	1851	72.6	100.0	29.3	15.8	321
Winter 1985/86	1839	72.1	100.0	27.8	15.1	305
Spring 1986	1840	72.1	100.0	27.6	15.0	302
Summer 1986	1845	72.3	100.0	27.1	14.7	297

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.94 **Replacement Energy Data for Arkansas Nuclear One 1**

Reactor Name:	Arkansas Nuclear One 1	Unit Size (MW):	836
Utility:	Arkansas Power and Light Co.	Heat Rate (Btu/kWh):	11,322
		Variable Fuel Cost (¢/10^6 Btu):	50
Power Pool:	20	Operating Status:	In Service
NERC Region:	SPP		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1320	72.1	100.0	33.7	25.5	369
Winter 1984/85	1320	72.1	100.0	33.9	25.7	372
Spring 1985	1319	72.1	100.0	32.5	24.7	357
Summer 1985	1320	72.1	100.0	33.5	25.4	367
Fall 1985	1319	72.1	100.0	32.3	24.5	354
Winter 1985/86	1319	72.1	100.0	32.8	24.9	360
Spring 1986	1319	72.1	100.0	31.6	24.0	347
Summer 1986	1320	72.1	100.0	32.4	24.6	355

[a] Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b] For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.95 Replacement Energy Data for Arkansas Nuclear One 2

Reactor Name:	Arkansas Nuclear One 2	Unit Size (MW):	858
Utility:	Arkansas Power and Light Co.	Heat Rate (Btu/kWh):	11,322
		Variable Fuel Cost (¢/10^6 Btu):	50
Power Pool:	20	Operating Status:	In Service
NERC Region:	SPP		

Season and Year	Seasonal Operating Statistics[a] Generation to be Replaced (10^6 kWh)	Capacity Factor (%)	% of Season in Service	Seasonal Production-Cost Increase Due to Short-Term Shutdown[b] Total ($\$10^6$)	Average per kWh Replaced (mills/kWh)	Average per Day ($\$10^3$/d)
Fall 1984	1354	72.1	100.0	34.6	25.5	379
Winter 1984/85	1354	72.1	100.0	34.8	25.7	382
Spring 1985	1354	72.1	100.0	33.4	24.7	366
Summer 1985	1354	72.1	100.0	34.4	25.4	377
Fall 1985	1354	72.1	100.0	33.2	24.5	363
Winter 1985/86	1354	72.1	100.0	33.7	24.9	369
Spring 1986	1354	72.1	100.0	32.5	24.0	356
Summer 1986	1354	72.1	100.0	33.3	24.6	365

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.96 Replacement Energy Data for Grand Gulf 1

Reactor Name:	Grand Gulf 1	Unit Size (MW):	1,250
Utility:	Mississippi Power and Light Co. (Major Owner)	Heat Rate (Btu/kWh):	11,388
		Variable Fuel Cost (¢/10^6 Btu):	44
Power Pool:	26 (90%), 17 (10%)	Operating Status:	Planned
NERC Region:	SPP (90%), SERC (10%)		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1977	72.2	100.0	50.0	25.3	548
Winter 1984/85	1979	72.3	100.0	50.8	25.7	557
Spring 1985	1983	72.4	100.0	49.8	25.1	546
Summer 1985	1980	72.3	100.0	50.1	25.3	549
Fall 1985	1981	72.4	100.0	52.5	26.5	575
Winter 1985/86	1981	72.4	100.0	49.3	24.9	540
Spring 1986	1984	72.5	100.0	50.0	25.2	548
Summer 1986	1981	72.4	100.0	48.8	24.6	535

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.97 Replacement Energy Data for River Bend 1

Reactor Name:	River Bend 1	Unit Size (MW):	934
Utility:	Gulf States Utilities Co. (Major Owner)	Heat Rate (Btu/kWh):	11,322
		Variable Fuel Cost (¢/10^6 Btu):	50
Power Pool:	20	Operating Status:	Planned
NERC Region:	SPP		

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	-	-	-	-	-	-
Spring 1985	-	-	-	-	-	-
Summer 1985	-	-	-	-	-	-
Fall 1985	-	-	-	-	-	-
Winter 1985/86	1474	72.1	100.0	36.7	24.9	402
Spring 1986	1474	72.1	100.0	35.4	24.0	389
Summer 1986	1474	72.1	100.0	36.3	24.6	397

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.98 Replacement Energy Data for Waterford 3

Reactor Name:	Waterford 3	Unit Size (MW):	1,151
Utility:	Louisiana Power and Light Co.	Heat Rate (Btu/kWh):	11,322
		Variable Fuel Cost (¢/10^6 Btu):	50
Power Pool:	26	Operating Status:	Planned
NERC Region:	SPP		

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	1816	72.1	100.0	46.8	25.8	513
Spring 1985	1817	72.1	100.0	44.9	24.7	492
Summer 1985	1817	72.1	100.0	46.2	25.5	507
Fall 1985	1816	72.0	100.0	44.7	24.6	489
Winter 1985/86	1816	72.1	100.0	45.3	24.9	497
Spring 1986	1817	72.1	100.0	43.7	24.0	478
Summer 1986	1816	72.1	100.0	44.8	24.7	491

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.99 Replacement Energy Data for Wolf Creek 1

Reactor Name:	Wolf Creek 1	Unit Size (MW):	1,150
Utility:	Kansas Gas and Electric Co. (Major Owner)	Heat Rate (Btu/kWh):	11,322
		Variable Fuel Cost (¢/10^6 Btu):	50
Power Pool:	22	Operating Status:	Planned
NERC Region:	SPP		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	-	-	-	-	-	-
Spring 1985	1214	72.3	66.7	27.0	22.3	444
Summer 1985	1823	72.4	100.0	34.8	19.1	381
Fall 1985	1820	72.3	100.0	38.2	21.0	419
Winter 1985/86	1824	72.4	100.0	43.2	23.7	474
Spring 1986	1821	72.3	100.0	41.0	22.5	449
Summer 1986	1824	72.4	100.0	35.3	19.4	387

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.100 Replacement Energy Data for Diablo Canyon 1

Reactor Name:	Diablo Canyon 1	Unit Size (MW):	1,084
Utility:	Pacific Gas and Electric Co.	Heat Rate (Btu/kWh):	11,035
		Variable Fuel Cost (¢/10^6 Btu):	46
Power Pool:	27	Operating Status:	In Service
NERC Region:	WSCC		

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1718	72.4	100.0	84.1	49.0	922
Winter 1984/85	1709	72.0	100.0	81.8	47.9	897
Spring 1985	1701	71.7	100.0	74.2	43.6	813
Summer 1985	1712	72.1	100.0	76.0	44.4	833
Fall 1985	1716	72.3	100.0	81.5	47.5	893
Winter 1985/86	1660	69.9	100.0	79.2	47.7	868
Spring 1986	1697	71.5	100.0	71.0	41.9	779
Summer 1986	1712	72.1	100.0	73.3	42.8	803

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.101 Replacement Energy Data for Diablo Canyon 2

Reactor Name:	Diablo Canyon 2	Unit Size (MW):	1,106
Utility:	Pacific Gas and Electric Co.	Heat Rate (Btu/kWh):	11,035
		Variable Fuel Cost (¢/10^6 Btu):	46
Power Pool:	27	Operating Status:	Planned
NERC Region:	WSCC		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	-	-	-	-	-	-
Spring 1985	1121	69.4	66.7	45.7	40.8	751
Summer 1985	1746	72.1	100.0	77.6	44.5	851
Fall 1985	1751	72.3	100.0	83.2	47.5	912
Winter 1985/86	1745	72.0	100.0	80.9	46.4	887
Spring 1986	1650	68.1	100.0	72.4	43.9	793
Summer 1986	1746	72.1	100.0	74.7	42.8	819

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.102 Replacement Energy Data for Fort St. Vrain 1

Reactor Name:	Fort St. Vrain 1	Unit Size (MW):	330
Utility:	Public Service Co. of Colorado	Heat Rate (Btu/kWh):	11,053
		Variable Fuel Cost (¢/10^6 Btu):	33
Power Pool:	28	Operating Status:	In Service
NERC Region:	WSCC		

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	530	73.4	100.0	6.0	11.3	66
Winter 1984/85	521	72.1	100.0	4.3	8.2	47
Spring 1985	521	72.1	100.0	4.2	8.0	46
Summer 1985	521	72.1	100.0	3.6	7.0	40
Fall 1985	524	72.5	100.0	6.4	12.2	70
Winter 1985/86	521	72.1	100.0	4.0	7.7	44
Spring 1986	521	72.1	100.0	7.4	14.1	81
Summer 1986	521	72.1	100.0	3.5	6.8	39

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.103 Replacement Energy Data for Hanford N

Reactor Name:	Hanford N	Unit Size (MW):	860
Utility:	U.S. Department of Energy	Heat Rate (Btu/kWh):	11,000
Power Pool:	25	Variable Fuel Cost (¢/10^6 Btu):	47
NERC Region:	WSCC	Operating Status:	In Service

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1425	75.7	100.0	32.9	23.1	360
Winter 1984/85	1358	72.1	100.0	9.9	7.3	108
Spring 1985	1357	72.1	100.0	6.5	4.8	72
Summer 1985	1392	73.9	100.0	27.0	19.4	296
Fall 1985	1426	75.7	100.0	47.9	33.6	525
Winter 1985/86	1359	72.1	100.0	11.1	8.2	122
Spring 1986	1357	72.1	100.0	6.1	4.5	67
Summer 1986	1393	74.0	100.0	28.4	20.4	311

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars. The large variations in seasonal costs are primarily attributable to the wide variability and large contribution of hydroelectric generation in the Northwest Power Pool. Results are based on median hydroelectric conditions (see Ref. 28).

TABLE 4.104 Replacement Energy Data for Palo Verde 1

Reactor Name:	Palo Verde 1	Unit Size (MW):	1,304
Utility:	Arizona Public Service Co. (Major Owner)	Heat Rate (Btu/kWh):	11,035
Power Pool:	26 (79%), 27 (21%)	Variable Fuel Cost (¢/10^6 Btu):	46
NERC Region:	WSCC	Operating Status:	Planned

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	2062	72.2	100.0	78.7	38.2	862
Spring 1985	2049	71.7	100.0	71.3	34.8	781
Summer 1985	2078	72.8	100.0	81.1	39.0	889
Fall 1985	2064	72.3	100.0	75.6	36.6	828
Winter 1985/86	2064	72.3	100.0	77.3	37.5	847
Spring 1986	2056	72.0	100.0	69.7	33.9	764
Summer 1986	2079	72.8	100.0	77.6	37.3	850

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.105 Replacement Energy Data for Palo Verde 2

Reactor Name:	Palo Verde 2	Unit Size (MW):	1,304
Utility:	Arizona Public Service Co. (Major Owner)	Heat Rate (Btu/kWh):	11,035
		Variable Fuel Cost (¢/10^6 Btu):	46
Power Pool:	26(79%),27(21%)	Operating Status:	Planned
NERC Region:	WSCC		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	-	-	-	-	-	-
Winter 1984/85	-	-	-	-	-	-
Spring 1985	-	-	-	-	-	-
Summer 1985	-	-	-	-	-	-
Fall 1985	2064	72.3	100.0	75.6	36.6	828
Winter 1985/86	2063	72.2	100.0	77.3	37.5	847
Spring 1986	2055	72.0	100.0	69.7	33.9	764
Summer 1986	2072	72.6	100.0	77.5	37.4	849

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.106 Replacement Energy Data for Rancho Seco 1

Reactor Name:	Rancho Seco 1	Unit Size (MW):	873
Utility:	Sacramento Municipal Utility District	Heat Rate (Btu/kWh):	11,035
		Variable Fuel Cost (¢/10^6 Btu):	46
Power Pool:	27	Operating Status:	In Service
NERC Region:	WSCC		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1384	72.4	100.0	67.4	48.7	739
Winter 1984/85	1376	72.0	100.0	65.7	47.7	720
Spring 1985	1377	72.0	100.0	59.6	43.3	653
Summer 1985	1378	72.1	100.0	61.2	44.4	671
Fall 1985	1382	72.3	100.0	65.3	47.2	716
Winter 1985/86	1337	69.9	100.0	63.5	47.5	696
Spring 1986	1376	72.0	100.0	56.4	41.0	618
Summer 1986	1379	72.1	100.0	59.3	43.0	650

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.107 Replacement Energy Data for San Onofre 1

Reactor Name:	San Onofre 1	Unit Size (MW):	436
Utility:	Southern California Edison Co. (Major Owner)	Heat Rate (Btu/kWh):	11,124
		Variable Fuel Cost (¢/10^6 Btu):	93
Power Pool:	27	Operating Status:	In Service
NERC Region:	WSCC		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	691	72.4	100.0	29.7	43.0	326
Winter 1984/85	688	72.0	100.0	29.6	43.0	324
Spring 1985	639	66.9	100.0	25.8	40.4	283
Summer 1985	664	69.6	100.0	26.7	40.2	293
Fall 1985	684	71.7	100.0	28.6	41.9	314
Winter 1985/86	680	71.2	100.0	26.3	38.7	288
Spring 1986	651	68.2	100.0	23.9	36.8	262
Summer 1986	656	68.7	100.0	25.9	39.4	283

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.108 Replacement Energy Data for San Onofre 2

Reactor Name:	San Onofre 2	Unit Size (MW):	1,087
Utility:	Southern California Edison Co. (Major Owner)	Heat Rate (Btu/kWh):	11,124
		Variable Fuel Cost (¢/10^6 Btu):	93
Power Pool:	27	Operating Status:	In Service
NERC Region:	WSCC		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1722	72.3	100.0	75.2	43.7	824
Winter 1984/85	1712	71.9	100.0	73.0	42.6	800
Spring 1985	1600	67.2	100.0	65.6	41.0	719
Summer 1985	1637	68.7	100.0	67.3	41.1	738
Fall 1985	1688	70.9	100.0	72.6	43.0	796
Winter 1985/86	1617	67.9	100.0	71.0	43.9	778
Spring 1986	1576	66.2	100.0	62.6	39.7	686
Summer 1986	1608	67.5	100.0	64.6	40.2	708

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season that is in service, in undiscounted 1984 dollars.

TABLE 4.109 Replacement Energy Data for San Onofre 3

Reactor Name:	San Onofre 3	Unit Size (MW):	1,087
Utility:	Southern California Edison Co. (Major Owner)	Heat Rate (Btu/kWh):	11,124
		Variable Fuel Cost (¢/10^6 Btu):	93
Power Pool:	27	Operating Status:	In Service
NERC Region:	WSCC		

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1714	72.0	100.0	75.2	43.9	824
Winter 1984/85	1673	70.3	100.0	73.0	43.6	800
Spring 1985	1564	65.7	100.0	65.6	41.9	719
Summer 1985	1600	67.2	100.0	67.3	42.1	738
Fall 1985	1654	69.5	100.0	72.6	43.9	796
Winter 1985/86	1597	67.1	100.0	71.0	44.4	778
Spring 1986	1545	64.9	100.0	62.6	40.5	686
Summer 1986	1558	65.5	100.0	64.6	41.4	708

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars.

TABLE 4.110 Replacement Energy Data for Trojan 1

Reactor Name:	Trojan 1	Unit Size (MW):	1,080
Utility:	Portland General Electric Co. (Major Owner)	Heat Rate (Btu/kWh):	11,123
Power Pool:	25	Variable Fuel Cost (¢/10^6 Btu):	48
NERC Region:	WSCC	Operating Status:	In Service

	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
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)
Fall 1984	1790	75.7	100.0	47.2	26.4	517
Winter 1984/85	1705	72.1	100.0	13.4	7.8	147
Spring 1985	1704	72.1	100.0	7.9	4.6	86
Summer 1985	1748	73.9	100.0	33.8	19.3	370
Fall 1985	1791	75.7	100.0	61.3	34.2	672
Winter 1985/86	1706	72.1	100.0	15.2	8.9	167
Spring 1986	1705	72.1	100.0	7.3	4.3	80
Summer 1986	1750	74.0	100.0	36.6	20.9	401

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars. The large variations in seasonal costs are primarily attributable to the wide variability and large contribution of hydroelectric generation in the Northwest Power Pool. Results are based on median hydroelectric conditions (see Ref. 28).

TABLE 4.111 Replacement Energy Data for WNP 2

Reactor Name:	WNP 2	Unit Size (MW):	1,103
Utility:	Washington Public Power Supply System	Heat Rate (Btu/kWh):	11,123
Power Pool:	25	Variable Fuel Cost (¢/10^6 Btu):	48
NERC Region:	WSCC	Operating Status:	Planned

Season and Year	Seasonal Operating Statistics[a]			Seasonal Production-Cost Increase Due to Short-Term Shutdown[b]		
	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)
Fall 1984	1827	75.7	100.0	48.8	26.7	535
Winter 1984/85	1742	72.1	100.0	14.2	8.1	155
Spring 1985	1702	70.5	100.0	8.0	4.7	88
Summer 1985	1786	73.9	100.0	34.5	19.3	378
Fall 1985	1829	75.7	100.0	62.4	34.1	684
Winter 1985/86	1742	72.1	100.0	15.7	9.0	172
Spring 1986	1739	72.0	100.0	7.5	4.3	82
Summer 1986	1787	74.0	100.0	37.4	20.9	410

[a]Assuming no scheduled maintenance or refueling outages for this reactor but normal maintenance for all other units.

[b]For portion of season unit is in service, in undiscounted 1984 dollars. The large variations in seasonal costs are primarily attributable to the wide variability and large contribution of hydroelectric generation in the Northwest Power Pool. Results are based on median hydroelectric conditions (see Ref. 28).

5 OBSERVATIONS

Replacement energy costs for nuclear generating units in the United States depend on a number of key parameters. Data on those parameters must be extensively verified and corrected before a reasonable cost estimate can be developed. In addition, analysts must carefully address many complexities in representing utility systems. In this study, replacement energy costs were estimated for all U.S. reactors planned to be operating between fall 1984 and summer 1986. Observations on the results of the studies are summarized below.

Significant increases in production costs can be expected whenever an operating reactor is shut down. Replacement energy costs range from \$6,000 to \$922,000 per day of reactor outage. The wide variation reflects differences in reactor sizes and in the fuels and generating plants used to replace the lost nuclear generation.

Replacement energy costs exhibit a strong regional dependence. The results in Sec. 4 show a wide variation in the average production-cost increase per nuclear kilowatt-hour to be replaced.

Seasonal trends are significant in some regions and negligible in others. In regions where summer peak loads are much higher than other seasonal peak loads, the replacement energy costs were often lower in the summer than other seasons. Costs are lower because, for reliability reasons, little, if any, maintenance is scheduled during the summer peak load. Therefore, all generating units are available, while during the off-peak seasons many generating units are off-line for scheduled maintenance. Thus, the cost of generating an additional kilowatt-hour is frequently higher in the off-peak seasons when many of the lower-cost units are unavailable. Another important seasonal factor is variation in the amount of hydroelectric generation.

Potential reliability problems are important in some power pools. Some pools are expected to have relatively little reserve capacity, so the loss of a single nuclear unit would have a significant effect. Other pools (the southern subregion of SERC is one example) seem to have sufficient reserve capacity to sustain the temporary loss of a nuclear unit; when sales to other pools are considered, however, the loss of a nuclear unit could cause difficulties. If sales to other pools are curtailed, the reliability and generation costs for those pools will be affected. Studies that focus on individual utilities rather than power pools greatly magnify the reliability effects of potential reactor shutdowns.

Maintenance schedules affect replacement energy costs, especially on a seasonal basis. In particularly important cases in which a production-cost study is run for the designated reactor, the researcher should try to obtain the currently planned maintenance schedules from the utilities involved. The ICARUS model and ADAP data base make it possible to carry out such production-cost studies without investing a great deal of time to collect and check data. This modeling package provides a head start for case studies of particular reactors.

Several issues were identified in this study as needing further attention. The major issues include (1) estimations of economy exchanges under alternative shutdown conditions (especially for power pools with a potential for extensive purchases or sales outside the pool), (2) sensitivities to year-to-year variations in hydroelectric generating conditions, and (3) the role of system reliability in evaluating shutdown impacts and alternatives. Although there is no substitute for an up-to-date, case-specific analysis of reactor shutdowns, efforts in the three areas identified would significantly strengthen and extend the results that could be rapidly obtained from the modeling capability described in this report.

Economy exchanges are especially difficult to model because interties and system operations are dynamic. Hydroelectric representations, as included in this study, are based on average conditions that can, in fact, vary substantially from year to year. These variations can strongly influence the apparent costs of shutdowns in systems that contain substantial percentages of hydroelectric generating capacity. The issue of system reliability has only been touched upon in the case study of multiple shutdowns (App. B), yet it could become a major issue for some regions and power pools. System reliability is an especially important consideration if retrofits or other modifications force simultaneous shutdowns in interconnected pools that normally would rely on each other for emergency transfers as well as economy exchanges.

The modeling package used throughout this study is an extensive compilation of data and software for modeling electrical generating systems. The overall simulation procedure was automated by minimizing the required user inputs and parameter specifications. With the package, simulations can be rapidly assembled and, depending on the particular power pool characteristics, reasonable energy costs can often be estimated with few or no adjustments. In other cases, pool-specific refinements require closer attention and modification by the analyst. The modeling package allows more attention to be given to case-specific refinements that are important for accurately portraying the effects of nuclear unit shutdowns on generating systems.

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APPENDIX A: REFERENCE LIST OF ASSUMED REACTOR CAPACITIES AND START-UP DATES

TABLE A.1 Assumed Reactor Capacities and Start-Up Dates

NERC Region and Reactor	Power Pool	Maximum Dependable Capacity (MW)	Commercial Operation Date (month/yr)	Cumulative Capacity Factor as of 12/31/83
ECAR				
Beaver Valley 1	2	810	10/76	39.9
Beaver Valley 2	2	833	5/86	-
Big Rock Point 1	4	64	3/63	57.3
Donald C. Cook 1	1	1020	8/75	66.2
Donald C. Cook 2	1	1060	7/78	69.9
Davis-Besse 1	2	874	7/78	45.7
Enrico Fermi 2	4	1093	12/84	-
Midland 2	4	818	7/86	-
Palisades 1	4	635	12/71	50.2
Perry 1	2	1205	5/85	-
ERCOT				
Comanche Peak 1	5-6	1150	1/85	-
Comanche Peak 2	5-6	1150	7/86	-
MAAC				
Calvert Cliffs 1	7	825	5/75	73.3
Calvert Cliffs 2	7	825	4/77	78.8
Limerick 1	7	1065	4/85	-
Oyster Creek 1	7	620	12/69	58.1
Peach Bottom 2	7	1051	7/74	61.6
Peach Bottom 3	7	1035	12/74	61.9
Salem 1	7	1079	6/77	48.7
Salem 2	7	1106	10/81	48.0
Susquehanna 1	7	1032	6/83	69.0
Susquehanna 2	7	1052	11/84	-
Three Mile Island 1	7	776	1/85[a]	40.5
MAIN				
Braidwood 1	8	1120	4/86	-
Byron 1	8	1120	1/85	-
Byron 2	8	1120	4/86	-
Callaway 1	9-10	1188	1/85	-
Dresden 2	8	772	6/70	57.9
Dresden 3	8	773	11/71	58.4
Kewaunee 1	11	503	6/74	78.3
LaSalle 1	8	1078	10/82	-
LaSalle 2	8	1078	4/84	-
Point Beach 1	11	495	12/70	69.8

NERC Region and Reactor	Power Pool	Maximum Dependable Capacity (MW)	Commercial Operation Date (month/yr)	Cumulative Capacity Factor as of 12/31/83
MAIN (cont'd)				
Point Beach 2	11	495	10/72	79.2
Quad Cities 1[b]	8,12	769	2/73	63.2
Quad Cities 2[b]	8,12	769	3/73	59.6
Zion 1	8	1040	12/73	56.9
Zion 2	8	1040	9/74	59.2
MAPP				
Duane Arnold 1	12	515	2/75	52.8
Cooper 1	12	764	7/74	62.7
Fort Calhoun 1	12	438	6/74	65.6
LaCrosse 5	12	48	11/69	47.4
Monticello 1	12	525	6/71	74.6
Prairie Island 1	12	503	12/73	75.9
Prairie Island 2	12	500	12/74	80.8
NPCC				
Fitzpatrick 1	15	810	7/75	62.9
Ginna 1	15	470	7/70	69.0
Haddam Neck 1	14	569	1/68	82.5
Indian Point 2	15	864	8/74	58.1
Indian Point 3	15	965	8/76	40.7
Maine Yankee 1	14	810	12/72	68.8
Millstone 1	14	654	3/71	65.3
Millstone 2	14	860	12/75	61.3
Millstone 3	14	1150	5/86	-
Nine Mile Point 1	15	610	12/69	58.3
Pilgrim 1	14	670	12/72	58.0
Seabrook 1	14	1198	8/86	-
Shoreham 1	15	820	7/85	-
Vermont Yankee 1	14	504	11/72	71.0
Yankee Rowe 1	14	169	7/61	69.8
SERC				
Browns Ferry 1	18	1065	8/74	50.4
Browns Ferry 2	18	1065	3/75	54.9
Browns Ferry 3	18	1065	3/77	63.3
Brunswick 1	19	790	3/77	46.0
Brunswick 2	19	790	11/75	44.3
Catawba 1	19	1145	6/85	-
Crystal River 3	16	811	3/77	54.8
Farley 1	17	804	12/77	60.0
Farley 2	17	814	7/81	82.1
Harris 1	19	900	3/86	-
Hatch 1	17	764	12/75	55.7
Hatch 2	17	771	9/79	59.6

NERC Region and Reactor	Power Pool	Maximum Dependable Capacity (MW)	Commercial Operation Date (month/yr)	Cumulative Capacity Factor as of 12/31/83
SERC (cont'd)				
McGuire 1	19	1180	12/81	41.6
McGuire 2	19	1180	3/84	-
North Anna 1	19	877	6/78	60.3
North Anna 2	19	890	12/80	66.7
Oconee 1	19	860	7/73	60.9
Oconee 2	19	860	9/74	60.8
Oconee 3	19	860	12/74	65.2
Robinson 2	19	665	3/71	65.8
Sequoyah 1	18	1148	7/81	58.7
Sequoyah 2	18	1148	6/82	66.6
St. Lucie 1	16	822	12/76	65.8
St. Lucie 2	16	786	3/83	87.0
Surry 1	19	775	12/72	54.8
Surry 2	19	775	5/73	57.3
Turkey Point 3	16	666	12/72	65.1
Turkey Point 4	16	666	9/73	67.6
V.C. Summer 1	19	900	1/84	-
Watts Bar 1	18	1165	11/84	-
SPP				
Arkansas Nuclear One 1	20	836	12/74	57.8
Arkansas Nuclear One 2	20	858	3/80	57.2
Grand Gulf 1[b]	20,17	1250	9/84	-
River Bend 1	20	934	12/85	-
Waterford 3	20	1151	12/84	-
Wolf Creek 1	22	1150	4/85	-
WSCC				
Diablo Canyon 1	27	1084	6/84	-
Diablo Canyon 2	27	1106	4/85	-
Fort St. Vrain 1	28	330	7/79	22.7
Hanford-N 1	25	860	7/66	-
Palo Verde 1[b]	26,27	1304	12/84	-
Palo Verde 1[b]	26,27	1304	9/85	-
Rancho Seco 1	27	873	4/75	50.1
San Onofre 1	27	436	1/68	53.2
San Onofre 2	27	1087	8/83	-
San Onofre 3	27	1087	4/84	-
Trojan 1	25	1080	5/76	52.5
WNP 2	25	1103	7/84	-

[a]Expected date for return to service.

[b]Units jointly owned by more than one power pool.

Sources: *Coordinated Bulk Power Supply Program*, East Central Area Reliability Coordination Agreement, Canton, Ohio (April 1983 and April 1984).

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APPENDIX B: MULTIPLE-SHUTDOWN CASE STUDY

This appendix demonstrates, through the use of a sample case study, that replacement energy costs are not necessarily additive in the case of multiple shutdowns within a single power pool. Replacement energy costs would generally increase (per kilowatt-hour replaced) with multiple shutdowns because larger percentages of the replacement energy would have to be derived from higher-priced generation.

The rise in costs would be most apparent in power pools with a significant percentage of nuclear capacity and some capacity using premium fuels, such as oil and gas, which are substantially more expensive than other fuels. The system capacity mix and reserve margin also affect how much and how fast the costs of replacement energy increase with multiple shutdowns.

The Pennsylvania-New Jersey-Maryland Interconnection (PJM, referred to as Power Pool 7 in this report) was selected for this multiple-shutdown case study because it contains 11 nuclear units. These 11 units constitute more than 21% of the total system capacity (10,545 MW out of 49,112 MW total). Another reason for selecting PJM is that approximately 22% of its capacity (10,726 MW) is oil- and gas-fired steam units. Although large amounts of oil and gas use would generally cause higher per-unit costs in multiple shutdowns, the generating system does have a large reserve margin (nearly 39%) and significant coal-fired capacity (35% of total capacity), which both tend to moderate the cost-escalating effects. Still, the case studies do exhibit the anticipated increase in replacement energy costs in response to multiple shutdowns.

The multiple-unit simulations were treated somewhat differently than the single-unit studies with respect to cost adjustments for periods of planned reactor maintenance. As discussed in Section 2.3, the single-unit results were adjusted so that shutdown costs could be examined uniformly for all seasons in the two-year study period. For the multiple shutdown study, these adjustments were not required because the comparisons highlight annual averages rather than seasonal variations (which were of major interest for the single-unit cases).

In this appendix, comparisons of multiple-unit shutdowns with single-unit shutdowns are based on the original unadjusted simulation results. Therefore the annual cost averages used here are not directly shown in Tables 4.16-4.26. Also, to simplify the calculations for the multiple shutdown comparisons, results for the calendar year 1985 were used. These differ slightly from results for the period from winter 1984/85 through fall 1985.

Figure B.1 illustrates the differences in costs per kilowatt-hour for multiple shutdown conditions and the sum of costs for the corresponding individual shutdowns. The costs per unit of replacement energy are plotted as a function of the combined megawatts assumed to be shut down (bottom scale) and the combined kilowatt-hours of energy assumed to be replaced (top scale). All costs are given in undiscounted 1984 dollars.

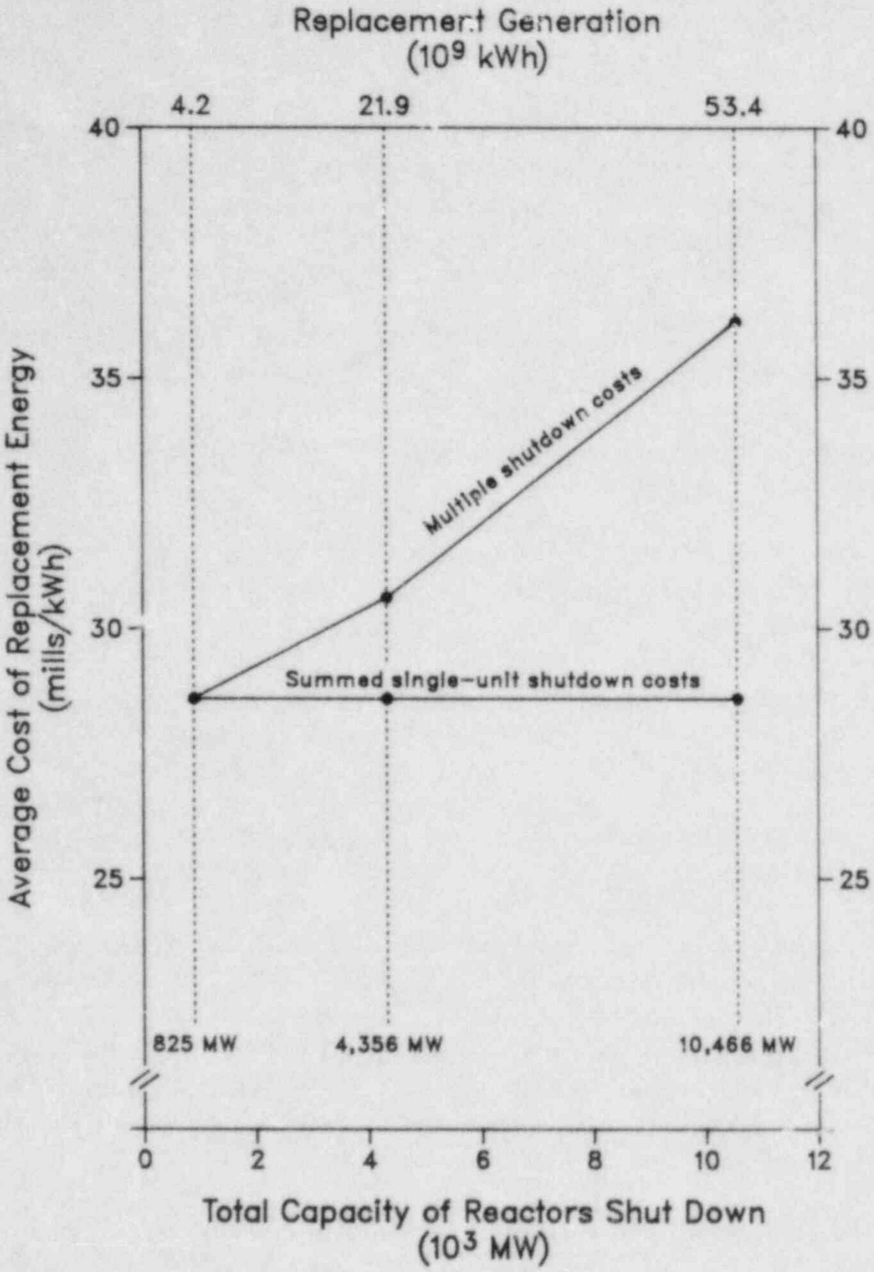

FIGURE B.1 Average Annual Replacement Energy Costs for Multiple Shutdown Case Study

The results in Fig. B.1 demonstrate the cost-escalating effect of multiple shutdowns in contrast to the constant costs per kilowatt-hour that are derived by summing the individual shutdown costs. The average cost per unit of energy increases by 26% when all 11 units are assumed shut down simultaneously.

TABLE B.1 Total Costs and Marginal Costs for the Multiple-Shutdown Case Study

Number of Units Shut Down	Capacity Shut Down (MW)	Total Replacement Energy Costs[a] ($\$10^6$)	Replacement Generation (10^9 kWh)	Average Replacement Energy Costs[a] (mills/kWh)	Marginal Energy Costs[a] (mills/kWh)
0	-	-	-	-	36.4
1	825	119	4.2	28.6	37.6
5	4,356	670	21.9	30.6	40.8
11	10,466	1,924	53.3	36.1	54.0

[a]Undiscounted 1984 dollars.

The summed costs for single-unit shutdowns remain essentially constant in the comparison because the generating units are sufficiently similar in capacities and assumed performance characteristics to yield fairly uniform shutdown costs when considered individually. Of course, the total dollar costs vary between units, primarily because unit sizes differ. The costs per kilowatt-hour, however, are essentially constant.

Table B.1 displays the total dollar costs and the marginal costs associated with the examples from Fig. B.1. It should be noted that comparisons between marginal system costs and average replacement energy costs must account for the variable components of nuclear costs (approximately 8 mills/kWh in these examples). These costs must be subtracted from marginal system costs to estimate marginal replacement costs for nuclear units at any of the four conditions shown in Table B.1.

Both total costs and marginal costs increase significantly as the number of units being shut down increases. The increase is especially apparent in the 11-unit shutdown case where marginal costs are 32% higher than marginal costs of a 5-unit shutdown and 44% higher than the marginal energy costs of a single-unit shutdown. For perspective, the average variable costs in this power pool are:

- 8 mills/kWh for a nuclear unit,
- 19 mills/kWh for a coal-fired unit,
- 50 mills/kWh for a residual-oil-fired steam unit, and
- 89 mills/kWh for a distillate-oil-fired combustion turbine unit.

The case studies do not fully account for possible changes in conditions outside the selected power pool that might influence shutdown costs. The analysis assumes that firm purchases from other interconnected systems remain the same in the shutdown cases as in the nominal case used for comparison. This assumption is subject to considerable uncertainty because interpool energy exchanges would be affected by factors such as (1) whether the shutdowns affect all power pools simultaneously, (2) how much notice is given before shutdowns, and (3) how significant the incentives are to increase purchases or decrease sales in the event of multiple shutdowns. In some power pools with low reserve margins, the costs of unserved energy could also contribute significantly to the costs of widespread multiple shutdowns.

The effect of curtailing firm energy purchases during multiple shutdown conditions was estimated with a sensitivity test. Firm purchases contribute 11% to the total energy demand for the power pool under consideration. For the case with all 11 reactors shut down, canceling purchases increased the average replacement energy costs compared to the case in which purchases remained constant. Replacement energy costs averaged about 59 mills/kWh with purchases curtailed in the shutdown case versus about 36 mills/kWh with purchases held constant.

As mentioned previously, the reserve margin in the PJM system is nearly 39%, a margin that prevents multiple shutdowns from causing the same magnitude of capacity shortages that would occur in other power pools. Still, reliability would become an issue for this system if all nuclear units had to be shut down simultaneously. In other systems, multiple shutdowns would lead to major reliability problems and substantial cost increases relative to those for single-unit shutdowns. Significant portions of replacement energy would have to originate from the highest-priced fossil fuels within the power pool and from emergency purchases from interconnected systems. The sensitivity of costs to multiple shutdowns is likely to vary significantly among the various regions and power pools; variations would reflect differences in fuel prices, reserve margins, and cost and availability of interpool exchanges.

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Seasonal replacement energy costs are estimated for potential short-term shutdowns of 108 nuclear electricity-generating units. These estimates were developed to help the Nuclear Regulatory Commission establish regulatory policies, particularly those requiring safety modifications that might necessitate temporary reactor shutdowns. Cost estimates were derived from probabilisitic 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. Seasonal costs are presented for the two-year period beginning with fall 1984 and ending with summer 1986.

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