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Reliability Estimation for Multiunit Nuclear and Fossil-Fired Industrial Energy Systems

W. G. Sullivan
J. V. Wilson
O. H. Klepper

OAK RIDGE NATIONAL LABORATORY

OPERATED BY UNION CARBIDE CORPORATION FOR THE ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION

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Printed in the United States of America. Available from
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road, Springfield, Virginia 22161
Price: Printed Copy \$5.00; Microfiche \$3.00

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Contract No. W-7405-eng-26

Engineering Technology Division

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Manuscript Completed - June 29, 1977

Date Published - August 1977

Prepared by the
OAK RIDGE NATIONAL LABORATORY
Oak Ridge, Tennessee 37830
operated by
UNION CARBIDE CORPORATION
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RELIABILITY ESTIMATION FOR MULTIUNIT NUCLEAR AND FOSSIL-FIRED INDUSTRIAL ENERGY SYSTEMS*

W. G. Sullivan† J. V. Wilson
O. H. Klepper

ABSTRACT

As petroleum-based fuels grow increasingly scarce and costly, nuclear energy may become an important alternative source of industrial energy. Initial applications would most likely include a mix of fossil-fired and nuclear sources of process energy. A means for determining the overall reliability of these mixed systems is a fundamental aspect of demonstrating their feasibility to potential industrial users.

Reliability data from nuclear and fossil-fired plants are presented, and several methods of applying these data for calculating the reliability of reasonably complex industrial energy supply systems are given. Reliability estimates made under a number of simplifying assumptions indicate that multiple nuclear units or a combination of nuclear and fossil-fired plants could provide adequate reliability to meet industrial requirements for continuity of service.

1. INTRODUCTION

Approximately 40% of the annual energy consumption in the United States is utilized by industrial processes, and about 40% of this is used to raise process steam. In 1971, approximately 75% of the industrial energy requirements were satisfied with direct fuel use of coal, oil, and natural gas.¹ However, uncertainties associated with future availabilities of these fuels create problems for large consumers of process steam that plan to replace oil- and gas-fired boilers with coal-fired units and/or nuclear steam supply systems. One certainty is the knowledge that oil and natural gas will not be abundant sources of energy in the future. Therefore, it seems reasonable that coal and nuclear, two fuels with a long-term resource base, be considered as alternative energy sources.

*The helpful suggestions by R. L. Scott of the Nuclear Safety Information Center are much appreciated.

†University of Tennessee.

The purpose of this report is (1) to present and illustrate procedures for calculating the reliability of multiunit nuclear and fossil-fired industrial energy systems; and (2) to determine from these preliminary calculations if industrial steam reliability requirements are likely to be met by multiunit nuclear steam sources or by a combination of nuclear and fossil-fired units. This information may be of particular interest to industries that are seeking alternative sources of energy. Because of the potential need for nuclear steam-generation systems to supplement and/or replace oil- and gas-fired sources of industrial steam, a means of determining the overall reliability of these "mixed" systems is a fundamental aspect of demonstrating their feasibility. Reliability here denotes the percent of clock time that a steam-supply system is serviceable and can satisfy the scheduled production requirements of an industrial plant. For purposes of the present report, this definition has been adopted as the primary meaning of "reliability" in the context of industrial production.

For large chemical plants, petroleum refineries, or steel mills, there is no single index of steam-supply reliability in widespread use because the various definitions currently being utilized are indicative of relative plant performance. The indicators vary with time, with manufacturing process, with companies, and with production goals of a particular plant. Several other indicators of the reliability of a steam-supply system are being widely used in the electric utility industry (such as capacity factor, availability, and forced outage rate); these are defined in Section 4, which gives representative data for several example problems.

An earlier report² presented results of a nationwide study aimed toward quantifying the reliability of present-day steam-supply systems. Major findings of this study for the chemical and petroleum refining industries are shown in Tables 1 and 2. Line N of Table 1 shows that steam-supply systems of chemical plants in the survey were unreliable an average of 1.96% of the service time (about 98% reliable). Petroleum refineries supply systems were approximately 92% reliable (100 - average value of line N in Table 2). These figures indicate the historical steam-supply reliabilities that will be used as benchmarks against which proposed

Table 1. Process steam system capacity,^a consumption rate, and reliability for chemical plants

Item of data	Plant																
	1	2	3 ^b	4	5	6	7	8	9	10	11	12	13	14	15	16	17
A. Average installed capacity, 10 ³ lb of steam/hr	4360	2440	800	1595	1700	1200	1220	690	780	805	525	360	220	320 ^c	300 ^d	192	144
B. Average on-line capacity, 10 ³ lb of steam/hr	3700	2320	758	1450	1475	1190	1155	659	670	764	500	330	212	265	280	175	136
C. Average on-line capacity, as percentage of A	84.8	95.1	94.8	91.0	86.8	99.2	94.7	95.5	85.9	94.9	95.2	9.17	96.2	82.8	93.3	91.1	94.4
D. Average actual steam usage, 10 ³ lb/hr	3300	1900	390	1170	1160	960	917	565	550	520	480	270	175	164	116	100	65
E. Average scheduled steam usage, 10 ³ lb/hr	3300	1900	400	1203	1230	960	917	580	600	530	480	280	175	164	116	100	65
F. Average actual steam usage, as percentage of B	89.2	31.9	51.5	80.7	78.6	80.7	79.4	85.7	82.1	68.1	96.0	84.8	82.5	61.9	41.4	57.1	47.8
G. Average safety margin, item B minus item D	400	420	368	280	315	230	238	94	120	244	20	50	37	101	164	75	71
H. Average safety margin, as percentage of D	12.1	22.1	94.4	23.9	27.2	24.0	25.9	16.6	21.8	46.9	4.2	18.5	21.1	61.6	141.0	75.0	109.2
I. Largest unit on line: 10 ³ lb of steam/hr	430	400	400	200	550	250	267	230	125	350	175	100	100	125	150	72	60
Average percentage of B	11.6	17.2	52.8	13.8	37.3	21.0	23.1	34.9	18.7	45.8	35.0	30.3	47.2	47.2	53.6	41.1	44.1
J. Safety margin as percentage of largest unit on-line (I)	93.0	105.0	92.0	140.0	57.3	100.0	89.0	40.9	96.0	69.7	11.4	50.0	37.0	80.0	109.0	104.2	118.3
K. Percent of time steam supply unable to meet scheduled requirements (E) due to random equipment outages	0.8	0	0	2.4	9.0	0	0.8	0	3.8	6.8	0	0	0	0	0	0.2	0
L. Percent of time scheduled steam production (E) was curtailed due to non-equipment-related outages	0	0.5	1.4	0	2.0	0.5	0	1.2	2.0	0	0	1.2	0	0	0	0.8	0
M. Percent of time plant was completely shut down for scheduled vacation or plant turnaround	0	0	0	0	0	0	0	2.5	1.0	1.1	0	3.8	3.8	3.8	3.8	2.2	0
N. Total percent of time scheduled steam production was curtailed (item K + item L)	0.8	0.5	1.4	2.4	11.0	0.5	0.8	1.2	5.8	6.8	0	1.2	0	0	0	1.0	0

^aTo convert lb/hr to kg/sec, multiply by 1.26×10^{-4} .

^bSteam data available only for central power plant.

^cDoes not include 65,000 lb/hr standby boiler.

^dDoes not include 45,000 lb/hr standby boiler.

Table 2. Process steam system capacity,^a consumption rate,
and reliability for petroleum refineries

Item of data	Refinery								
	1	2	3	4 ^b	5 ^c	6	7	8	9
A. Average installed capacity, 10 ³ lb of steam/hr	5820	3715	2376	1140	537	895	780	715	509
B. Average on-line capacity, 10 ³ lb of steam/hr	5450	3500	2250	1050	530	861	775	646	500
C. Average on-line capacity, as percentage of A	93.6	94.2	94.7	92.1	99.3	96.2	99.4	90.4	98.2
D. Average actual steam usage, 10 ³ lb/hr	4375	2800	1870	1012	500	780	749	496	311
E. Average scheduled steam usage, 10 ³ lb/hr	4375	2800	1870	1012	500	780	749	496	311
F. Average actual steam usage, as percentage of B	80.3	80.0	83.1	96.4	96.8	90.6	96.7	76.8	62.2
G. Average safety margin, item B - item D	1075	700	380	38	30	81	26	150	189
H. Average safety margin as percentage of D	24.6	25.0	20.3	3.8	3.3	10.4	3.5	30.2	60.8
I. Largest unit on-line:									
10 ³ lb of steam/hr	550	350	500	200	287	470	280	440	135
Average percentage of B	10.1	10.0	22.2	19.1	30.9	54.6	36.1	68.1	27.0
J. Safety margin as percentage of largest unit on line (I)	195.5	200.0	76.0	19.0	10.5	17.2	9.3	34.1	140.0
K. Percent of time steam supply system unable to meet scheduled requirements (E) due to random equipment outages	5.8	0.8	8.3	0	30.1	17.3	3.8	1.4	0
L. Percent of time scheduled steam production (E) was curtailed due to non-equipment-related outages	0	0	0.8	1.9	0	0.3	0.3	0	0
M. Percent of time refinery was completely shut down for scheduled vacation or plant turnaround	0	0	0	0	0	0	0	0	0
N. Total percent of time scheduled steam production was curtailed (item K + item L)	5.8	0.8	9.1	1.9	30.1	17.6	4.1	1.4	0

^aTo convert lb/hr to kg/s, multiply by 1.26×10^{-4} .

^b172,000 lb/hr purchased steam (nameplate capacity equals 180,000 lb/hr).

^c10,000 lb/hr purchased steam.

industrial energy systems can be compared. The approach used to estimate the combined reliability of multiunit steam-supply systems will take three fundamental considerations into account: (1) the total amount of steam required under normal and maximum operating conditions by individual companies and/or industrial parks, (2) the technical features of alternative configurations and nuclear and fossil units capable of satisfying industrial energy reliability requirements, and (3) the forced outage characteristics, startup times, and load-following behavior of the systems being evaluated. Technical features and costs of various nuclear steam-supply systems are briefly discussed in Appendix A.

2. REACTOR AND BOILER RELIABILITY DATA

2.1 Reactor Operation

The reliability of nuclear reactor systems is documented in detail in a series of reports entitled Operating Units Status Report: Licensed Operating Reactors: Data for Decisions,³ which is also referred to as the NRC Gray Book. This report is issued monthly by the Nuclear Regulatory Commission (NRC) for use by the Federal Energy Administration (FEA), Energy Research and Development Administration (ERDA), Federal Power Commission (FPC), and other federal agencies. Detailed monthly histories of forced and scheduled outages for commercial reactor systems can be developed from the information given in the report. Representative monthly statistics from the July 1976 report, which presents operating experience for June 1976, are shown in Tables 3 to 6 and in Fig. 1. The terms used in the NRC report are defined in Appendix B. The NRC issued an annual evaluation report for the 1973 data,⁴ and a report that combines the 1974 and 1975 data will be issued in the winter of 1976-77.

Power generation data and a breakdown of outage frequencies and durations appear in Tables 3 and 4. Table 3 gives various statistics for June 1976. Of particular interest here are average reactor availability factors and average forced outage rates during the month. Table 4 shows that the percent of clock time for scheduled outages in June 1976 was about twice that for forced outages; Table 5 gives the reasons for the June shutdowns. Notice that hours lost for refueling amounted to about one-third of the total hours lost. Equipment failures were the most common reason for shutdowns, although they represent only about one-fourth of total hours lost. Additional detailed monthly statistics that highlight reactor availability factors, unit forced outage rates, etc., for each licensed nuclear power plant are also given in the NRC reports.

The data provided in Table 6 for 13 power plants illustrate the variation in key operating statistics among plants. The data are defined in Appendix B. Reactor data pertain to the reactor plant only; unit data refer to the performance of the reactor and its associated power conversion system. Reactor availabilities ranged from 0 to 100%, while unit

Table 3. Power generation data for commercial nuclear power units (June 1976)

<u>Licensed power reactors</u>		
<u>Number</u>		<u>Capacity^a [MW(e) net]</u>
54	In commercial operation	35,660
3	In power ascension phase	2,055
1	Unavailable for power production ^b	262
<u>58^c</u>		<u>37,977</u>

Power generation

	<u>Report month</u>	<u>Previous month</u>	<u>January-June</u>
Gross electrical, MWhr	16,100,253	12,359,865	85,130,110
Net electrical, MWhr	15,348,011	11,704,129	80,877,502
Average reactor service factor, %	74.0	59.5	65.2
Average reactor availability factor, ^d %	80.1	63.4	68.1
Average unit service factor, %	72.1	56.8	63.0
Average unit availability factor, %	74.1	57.4	63.5
Average unit capacity factor, (MDC), %	66.3	54.2	58.1
Average unit capacity factor [design MW(e)], %	59.3	45.9	52.3
Forced outage rate, %	10.0	15.3	13.4

^aBased on maximum dependable capacity; design capacity used if MDC not determined.

^bIndian Point 1 shut down.

^cPeach Bottom 1 not included; being decommissioned.

^dThe average reactor availability factor is of interest in the present study because it indicates the fraction of the time that the reactor is available for service hours plus the reserve shutdown hours divided by the gross hours in the period.

Table 4. Outage data for commercially operated nuclear power plants (June 1976)^a

	<u>Number</u>	<u>Hours</u>	<u>Percent of clock time</u>	<u>Lost electricity production (MWhr)</u>
Forced outages during month	54	3,291.5	8.8	1,727,807
Scheduled outages during the month	27	7,537.7	19.7	2,931,753
<u>Total</u>	<u>81</u>	<u>10,829.2</u>	<u>28.5</u>	<u>4,659,560</u>

^aCapacity factor of 0.75 was assumed for units that did not operate at all during the period.

Table 5. Shutdown information for commercial nuclear power units (June 1976)

Shutdowns greater than 12 hr each			
Unit	Reason	Unit	Reason
Arkansas 1	2A	Nine Mile Point	B
Big Rock Point	H	Oconee 2	C
Browns Ferry 1	B	Peach Bottom 2	A, C
Browns Ferry 2	B	Pilgrim	A, C, G
Brunswick 2	A	Prairie Island 1	A, H
Connecticut Yankee	C	Prairie Island 2	A, B
Dresden 1	B	Quad Cities 1	B
Dresden 2	A, B	Rancho Saco	A
Duane Arnold	B	Surry 2	C
Fitzpatrick	A, 2G	Trojan	B
Hatch 1	A	Turkey Point 3	2A
Indian Point 2	C	Turkey Point 4	2A, C
LaCrosse	D	Vermont Yankee	C, G
Maine Yankee	A	Zion 1	A, C, H
Monticello	B	Zion 2	4B, C

Reasons for shutdown

Reason	Number	Total time lost (hr)
A — Equipment failure	33	2,754.73
B — Maintenance of test	15	2,903.05
C — Refueling	8	3,465.10
D — NRC restriction	2	720.00
E — Operator training and license examination	0	0
F — Administrative	0	0
G — Operational error	11	166.90
H — Multiple reasons	12	819.40
Total	81	10,829.18

forced outage rates ranged from 0 to 18.6%. Figure 1 shows considerable variation in average unit forced outage rates and availability factors during the first six months of 1976.

Table 6. Selected monthly unit data as of June 30, 1976

Unit name/ utility	Unit size [MW(e)]/ type	Maximum dependable capacity	Reactor service factor (%)	Reactor availability factor (%)	Unit service factor (%)	Unit availability factor (%)	Unit capacity factor (MDC) (%)	Unit capacity factor (design) (%)	Unit forced outage rate (%)	Summary
Arkansas 1 Arkansas Power & Light	850 PWR	836	12.8	38.1	6.3	6.3	2.8	2.8	2.8	Unit started up after removal of the surveillance tubes. An additional shutdown was experienced to replace burned exciter bearing and repair stator.
Beaver Valley 1 Duquesne Light Co.	852 PWR	852	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Initial criticality achieved at 6:45 p.m. 05-10-76. ASLB issued license for 35% rated power on 05-28-76. The unit is in Mode 1, operation, and performing power testing. ASLB issued full-power license 07-02-76.
Big Rock Point 1 Consumers Power	72 BWR	71	4.8	4.8	0.0	0.0	0.0	0.0	0.0	Core loaded 05-02-76, spray head installed 05-12-76. Component leak rate completed. Startup scheduled 07-07-76. Plant life exemption and new license received. Physics testing completed 06-17-76.
Browns Ferry 1 Tennessee Valley Authority	1065 BWR	1065	0.0	100.0	0.0	0.0	0.0	0.0	100.0	License was amended to permit fuel loading only on 07-02-76. Fuel loading began 07-04-76.
Browns Ferry 2 Tennessee Valley Authority	1065 BWR	1065	0.0	100.0	0.0	0.0	0.0	0.0	100.0	TVA considers unit 2 ready for re-fueling.
Brunswick 2 Carolina Power & Light	821 BWR	790	97.6	97.6	96.2	96.2	64.0	61.6	3.8	
Calvert Cliffs 1 Baltimore Gas & Electric Co.	845 PWR	800	99.2	100.0	99.0	99.0	98.7	93.5	1.0	An order for modification of license was issued 06-17-76 to add the provision that peak linear heat generation be limited to 13.9 kw/ft.
Connecticut Yankee Connecticut Yankee Atomic Power Co.	575 PWR	540	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Low physics testing completed 07-05-76. Unit expected to be at 100% power by 07-09-76.
Cook 1 Indiana & Michigan Power Co.	1090 PWR	931	98.7	98.7	98.5	98.5	96.2	94.9	1.5	Unit operated at 100% of rated power for testing.
Cooper Nuclear Station Nebraska Public Power District	778 BWR	764	100.0	100.0	100.0	100.0	67.0	65.8	0.0	Unit generation limited by MAPLHGR due to core plugging.
Dresden 1 Commonwealth Edison	200 BWR	207	89.7	89.7	88.2	88.2	64.6	63.6	0.0	Load was limited due to fuel restrictions of MAPLHGR limits.
Dresden 2 Commonwealth Edison	809 BWP	794	94.4	94.4	87.6	87.6	74.5	71.1	6.6	Off-gas explosion in "A" SJAE; operation continued using "B" SJAE while rupture diaphragms were replaced.
Dresden 3 Commonwealth Edison	809 BWR	794	100.0	100.0	100.0	100.0	71.1	67.9	0.0	"3C" condensate booster pump impeller was modified and tested. "3A" and "3B" will be modified this summer.

Fig. 1. Reliability indices for commercial nuclear power units (June 1976). From Ref. 3.

The capacity factor is another commonly used indicator of power plant reliability. Figure 2 lists average reductions in capacity factor (defined in Appendix C) for seven nuclear plants,⁵ which represents a good cross section of industry. These include four pressurized-water reactors (PWRs) and three boiling-water reactors (BWRs); the ages of these reactors vary from 2.5 to 12.0 years and the average capacity is 512 MW(e) net. There was considerable variation in performance among units; note that about 14.4% of the reductions in capacity factor resulted from causes unrelated to reliability. Almost half of these

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Fig. 2. Average reductions in capacity factor for seven units (4 BWRs). From Ref. 5.

resulted from normal refueling. Fuel and primary plant difficulties accounted for a 14.6% reduction in average capacity factor, and the secondary plant accounted for 8.3%. The total reduction in capacity factor was 37.3%.

Reliability data from industry sources are compiled by the Edison Electrical Institute (EEI) and published annually; their reports are available about nine months after the reporting period.⁶ Many of the EEI statistics will be useful in determining the overall reliability of hybrid (mixed nuclear and fossil) systems that may be used by manufacturing industries to produce process energy. For example, a summary of average forced and scheduled outage durations for fossil-fueled and nuclear power plants is given in Table 7. Definitions of terms included in the reports are given in Appendix C. Differences between these definitions and those of Ref. 3 are discussed in Appendix D.

Table 7. Average forced and scheduled outage durations for fossil-fired and nuclear power plants⁶

Size of plant (MW)	Forced outages		Maintenance and planned outage durations (time of outage) (months)
	EFOR ^a (%)	Duration of outage (days)	
Fossil			
60-89	2.8	2.2	0.8
90-129	4.5	1.9	1.0
130-199	4.8	1.9	1.0
200-309	7.6	2.3	1.2
390-599	12.9	2.6	1.4
600 up	21.9	2.9	1.4
All nuclear	15.6	3.4	1.6

^aEFOR — equivalent forced outage rate — includes the effects of forced partial outages as well as full forced outages. In many cases the forced outage rate is based solely on full forced outages. Based on this viewpoint, FORs are generally about two-thirds of the EFOR for large nuclear and fossil-fired units.

Additional information regarding nuclear steam supply system (NSSS) forced outage rates relevant to the present study is quoted below:⁷

"As of March 1975, nuclear units had been in a forced outage state due to equipment failure for approximately 10% of their total commercial service life. This amounted to about 22 unit years of forced outage. Nearly 11 of these outage years were accounted for by approximately 70 major incidents (greater than 500 hour outage duration) in large plants. The remaining 11 unit years of forced outage are attributable to several thousand incidents. As a rough rule-of-thumb, 40% of the incidents are in nuclear-related elements; the remaining 60% are balance-of-plant items."

The Electric Power Research Institute (EPRI) conducted detailed studies of commercial BWRs and PWRs for the period July 1974 through March 1975. Findings of the studies indicated that nuclear units undergo three to five scheduled outages per year, exclusive of those for refueling, and last 80 to 100 hr per incident.⁷ The number of annual forced outages at nuclear units included in the survey ranged from 11 to 15. The average times of forced outages were 68 and 57 hr for BWRs and PWRs, respectively.

Reactor availabilities and forced outage rates can also be obtained from the EEI reports. Reliability data for nuclear units of all sizes are given in Table 8, along with the average time between forced outages for the reactor. This quantity, which is referred to as "mean time between failures" (MTBF), is of particular interest in this study. The MTBF for nuclear steam-supply systems (NSSS) was 1969 hr for the period 1965 through 1974. Definitions of terms are given in Appendix C.

Other sources of data on this subject include Nuclear Engineering International (March 1975), Nuclear Safety (March-April 1975), and Nuclear Power Growth (WASH 1139-74). However, the most up-to-date source is the NRC monthly report.³

As indicated in Fig. 2, one of the major influences on steam availability from nuclear reactors is the refueling time; the major influences on reliability of a reactor are the size and age of the system. In selecting representative data for example problems that demonstrate the evaluation procedure, these two subjects are examined further at this point.

Table 8. Availability and forced outage rates of major components in nuclear units of all sizes^a

Component	Operating availability (%)	Forced outage rate (%)	Mean time between forced outages (hr)
Reactor	81.5	6.5	1,969
Turbine	92.6	3.2	4,146
Condenser	97.6	0.5	14,181
Generator	97.6	0.8	27,180
Other	97.9	1.2	4,773
Total unit	75.6	11.4	942

^aData base consists of 43 units with combined unit years equal to 123. Source: Ref. 6.

2.2 Reactor Refueling

A study by EPRI shows the relative effect that scheduled outages for refueling have on nuclear power plant availability.⁷ Curve A in Fig. 3, which illustrates the cumulative availability (as defined in Appendix C) of nuclear units between refueling periods, yields some perspective on how well nuclear units perform between major scheduled service outages. Achieved values in excess of 95% represent outstanding performance. The present impact of refueling on availability is suggested by comparing curves A and B, the latter of which includes the impact of refueling. Care must be taken in interpreting these data since the industry as a whole is not in "refueling equilibrium." A large number of units that have not undergone first or second refuelings are combined with units that have undergone extensive refuelings and others whose limited refueling downtime is masked by a discrete long-term outage. Mature units have been unavailable 13 to 17% of their total life for refueling.

In general, it has been found that the average reliability of nuclear power plants improves after the unit has been refueled twice.

Fig. 3. Plot of cumulative lifetime availability factor illustrating refueling outage impact as of Mar. 1, 1975. From Ref. 7.

That is, operational maturity of a nuclear plant cannot be expected until after the plant has gone through an initial "shakedown" period in which early difficulties are detected and resolved. Another EPRI publication⁵ shows that the average capacity factor (defined in Appendix C) for all nuclear plants from the time they were commercially operative is 57%, but that this value increases with time and experience.

After the second refueling, the average capacity factor for all plants was 74%, as depicted graphically in Fig. 4.

The average time for reactor refueling, which occurs about every 18 months, was estimated⁷ to be 1736 hr. This means that the expected annual refueling time is about 1200 hr for commercial BWRs and PWRs.

Fig. 4. Capacity factor distributions. From Ref. 5.

However, the report notes that many current nuclear units were not designed to allow rapid refueling because this capability was not considered of major importance at the time. Cumulative data on refueling outages show considerable evidence of a "learning curve" effect, so that it is reasonable to expect refueling times to decrease by 400 to 600 hr/year in the near future. Consequently, a range of refueling times is utilized in some of the illustrative problems presented later.

2.3 Reactor Reliability vs Unit Size and Age

Both the NRC and the EEI statistics indicate that reliability, as measured in terms of average forced outage rates and availability factors, decreases as the size of the nuclear unit increases. This apparent phenomenon may be caused by the relatively small number of units comprising the data base and/or the lack of design maturity in the larger units.

In an FEA study,⁸ it was reported that reliabilities of older and smaller nuclear units are generally better than those of the newer and larger designs. The relationship between unit size escalation, design maturity, and reliability was also investigated. Figures 5 and 6, which are taken from the FEA report, show average yearly availability factors (defined in Appendix C) for two classes of nuclear power plants. Figure 5 shows average availability factors vs years of service for the Yankee-Rowe, Indian Point No. 1, and Dresden No. 1 units, which are in the 175- to 260-MW range. These units were first-of-a-kind power reactors and have been in service for 12 to 14 years. The information is plotted in Fig. 6 for the Humboldt Bay and Big Rock Point units (70 and 80 MW), which have been in operation for about 12 years.

For both groups of units, the unit availability shows a general increase over the first 3 to 4 years of operation followed by a gradual decline in more recent years. Figures 5 and 6 also show that the availability after 10 years of service is at least as good as or better than it was in the initial years, with smaller units showing more improvement than the larger units.

Fig. 5. Average yearly availability factor — Dresden 1, Indian Point 1, and Yankee-Rowe, 1962-1972. From Ref. 8.

Data from the July 1976 issue of the NRC report³ were analyzed to gain some insight into recent experience with reliability vs unit size. Results shown in Table 9 indicate that average reactor availability factors and average unit forced outage rates were adversely affected by larger unit sizes. Since only power plants that generated electricity during June were considered, it is realized that this sample of one month's data does not produce statistically significant results but rather indicates a trend. Table 9 is presented to further prove the validity of the FEA claims.

Nuclear data reported in this and the previous two subsections are utilized in Section 4 in evaluating the overall reliabilities of multiple-unit nuclear and fossil-fired steam supply systems.

Fig. 6. Average availability factor vs years of service - Humboldt Bay and Big Rock Point, 1963-1972. From Ref. 8.

Table 9. Unit size vs reactor availability factor and unit forced outage rate for plants operating in June 1976

Unit size	Average reactor availability factor (%)	Average unit forced outage rate (%)
<175 MW(e) (1 plant)	100.0	0.0
175-499 MW(e) (10 plants)	96.5	7.5
500 MW(e) and above (34 plants)	86.9	7.6

2.4 Reliability of Fossil-Fired Boilers

Reliability data for fossil-fired boilers are published yearly by EEI.⁶ Although these data are gathered from electric utilities on a voluntary basis, they are believed to comprise a representative sample of boiler manufacturers and the various sized units in common use. Definition of terms follows EEI practice as given in Appendix C. Generally speaking, data bases for the nuclear plants are more comprehensive and current than those from fossil plants.

Table 10 shows operating availability, forced outage rate, and mean time between forced outages for various sized boilers. As indicated in the table, total unit forced outage rates are considerably higher for the large boilers. The rates for boilers of 600 MW and above exceed 9%, and the availability of these systems is approximately 82%. For units of the same size, these statistics are comparable to the Nuclear steam supply (NSS) portion of electrical power stations.

Table 10. Availability and forced outage rates
of fossil-fired boilers (1965-1974)

Boiler size [MW(t)]	Operating availability (%)	Forced outage rate (%)	Mean time between forced outages (hr)
60-89	93.3	1.2	3664
90-129	90.9	2.4	2064
130-199	91.0	2.5	1748
200-389	88.2	3.6	1563
390-599	84.6	5.6	1155
600 and above	82.2	9.3	793

In a companion study,² it was found that most industrial boilers used to produce process steam have a capacity of 31.5 kg/s (250,000 lb/hr of steam) or less. This roughly corresponds to the 60- to 89-MW category in Table 10. The figures for this size boiler correspond

reasonably well with average equipment (boiler) related outages reported by the chemical and petroleum refining industries in the study cited above.

Selected reliability measures⁶ for 600-MW and larger fossil-fired units are shown in Table 11. These data were gathered from electric utilities that use boilers to meet a highly variable demand. Boilers used to produce industrial process steam are not subject to widely fluctuating demands and may have higher operating availabilities than their counterparts in electrical utilities. For purposes of demonstrating the methodology, however, it is assumed that the EEI data are representative of industrial boiler experience. Therefore, the data of Tables 10 and 11 are utilized in the illustrative problems.

Table 11. Availability and forced outage rates of major components in fossil-fired units 600 MW and larger^a

Component	Operating availability (%)	Forced outage rate (%)	Mean time between forced outages (hr)
Boiler	82.2	9.3	793
Turbine	88.4	3.4	3,341
Condenser	96.3	0.2	19,208
Generator	91.4	3.5	8,698
Other	95.0	1.3	2,791
Total unit	73.3	15.8	481

^aData base consists of 81 units with combined unit years equal to 285.

3. ANALYTICAL PROCEDURES

Two methods have been used in this study to estimate the reliability of steam supply systems. The first is a Monte Carlo method, in which a series of operating histories is calculated and the reliability of the system determined by analyzing these histories. The second is a probability calculation similar to that used in the electric power industry to calculate loss of load probability (LOLP) and loss of energy probability (LOEP). The first method can be used for systems of considerable complexity, while the second can become very cumbersome for complicated systems. These methods are described below.

It is worth noting that the reliability requirements for combined nuclear and fossil-fired fuel steam supplies for industry differ with application and differ from those in the electric power industry. In the electric power industry, one commonly used reliability criterion is "it is not acceptable to be unable to meet energy demands more than one day in ten years." Although voltage reductions are common, they are not considered in determining the generating capacity needed to meet the reliability requirement. This reflects the fact that although some customers are far better able to cut back on power use than others, it is often impossible or else socially or politically impracticable to get them to do so when necessary. Hence, the electric utilities must have a large reserve generating capacity (15 to 20% above peak load is a common criterion) with its attendant capital cost. In some industries (e.g., nylon manufacture), a steam failure is so disruptive that a reliability criterion as strict as that of the electric power industry is justified. In other industries, a steam failure results in momentary loss of production without major other effects, and a lower reliability is acceptable. In many industries, part of a plant may be shut down with little penalty to maintaining operations in another more essential part. Typically, an electric utility also has a high reliability because its generating capacity is spread among many independent sources, either in its own system or in the regional power reliability council of which it is a member. In contrast, much industrial steam will come from a small number of boilers with no interconnections to external power sources. The

reliability requirements for each industrial installation should be established on an individual basis, taking into account the impact on the installation of a forced outage of steam supply; some installations can easily curtail operations while others incur a heavy economic penalty if they are forced to shut down.

Another factor to consider is the use of the steam capacity in excess of that required to generate process steam. One policy is to place boilers not needed to meet current steam requirements on hot (or cold) standby, while another is to use the excess steam to generate by-product electricity. A recent survey shows that most plants with large steam requirements also have large electric power requirements.⁹ Many of these already have their own fossil-fueled electricity generating plants. In general, these operate on top of the process steam cycle; that is, turbines for generating electricity use high-temperature steam and exhaust low-temperature steam for process use, resulting in a very low unit electricity cost. In general, it may be most economical for most plants to use their excess steam capacity to generate electricity, first to displace that which they purchase from an electric utility and then to sell (if a buyer can be found). The legal, economic, and environmental issues associated with this mode of operation have been studied elsewhere.¹⁰

In the Monte Carlo calculation, one can assume that excess steam is used to generate electricity or that excess boilers are placed on standby. If one or more units are off line because of forced and/or scheduled outages, generation of electricity is initially curtailed. When the combined outage is severe enough, steam production will drop below requirements, resulting in an unreliable steam-supply system. In the case where the system is characterized as unreliable, rules for determining how the steam loss affects production processes can be specified by the user of the computer program developed in the present study. This option is included because large reductions in steam supply will affect industries in many different ways. In addition, if the user has more steam generators operable than he chooses to include in a particular alternative, the mix of units can be varied and evaluated as separate alternatives. With this approach, the effect of keeping high-cost units on "permanent standby" can be evaluated. Such units would be called upon in emergency situations only.

It should be emphasized that these procedures can be used to determine the reliability of systems having various combinations of nuclear and fossil-fired steam generators if the outage rate of the individual generators is known beforehand. These procedures do not include factors that determine individual reactor or fossil-fired boiler outage characteristics — these values are assumed to be given quantities for present purposes.

The accuracy of the calculated results will depend on how well the input data are known and on the calculational techniques employed. For the probabilistic method, techniques are available to express the standard deviation of the results in terms of the standard deviations of the input data. For the Monte Carlo calculations, the input data can be represented directly in terms of an appropriate distribution function. (In the sample problems, uniform distributions were assumed for simplicity.) The accuracy of the results then improves as the number of case histories is increased. A detailed discussion of these aspects is beyond the scope of the present report.¹¹

3.1 Monte Carlo Computer Program

The purpose of this computer program is to estimate the reliability of an industrial steam supply system consisting of multiple sources. The operating characteristics (outage frequency and duration, time required to place the unit on line, etc.) of individual power sources must be known so that the various operating modes of the system can be defined.

A flow diagram for the Monte Carlo calculation of example 3 is shown in Fig. 7. A corresponding diagram for example 2 would differ only in minor details.

A computer is used to keep track of a simulated period of operation (normally 12 to 18 months) of the plant, including hourly steam generating capacity, hourly steam load, and hourly steam used to make electricity. The computer tallies the hours when the load is not met, the steam from each boiler, the electricity generated, and similar quantities of interest. The computer program uses appropriate input data and random numbers to determine the occurrence of forced outages, the lengths of repair periods,

Fig. 7. Flow diagram for the Monte Carlo calculation of example 3.

and other random variables. Different computer runs will give different results because different sets of random numbers are used from one simulation to the next. To determine system reliability, one makes a series of such calculations and keeps a running average of the results. When this average seems to have stabilized to a narrow range of values, it is a reasonable estimate of the quantity desired. An error estimate is obtained by determining the mean and standard deviation of the results and applying statistical theory assuming a normal distribution of simulation outcomes. The "33 years of operating experience" reported in a later example problem represents the results of 33 independent calculations for one year each, with a different set of random numbers for each calculation.

The Monte Carlo method makes it possible to incorporate into the calculation a number of assumptions that are dependent on the individual installation. In addition to the assumption mentioned above — that excess steam is used to generate electricity — other assumptions concern power load requirements and boiler characteristics.

It is assumed that in event of a steam supply failure, each industrial plant will modify its steam consumption as a function of time and amount of steam available. The function defining the steam usage after failure is read into the computer program as input data.

A number of operating conditions, represented by input data, are required for each boiler. The first of these is rated steam generating capacity, usually stated in millions of pounds per hour. Next are scheduled time between overhauls and scheduled duration of overhaul. Extensions of the scheduled overhaul period can be provided by letting this variable take on random values in accordance with a prescribed distribution function. The mean time between failures and mean time for repairs are additional required data. The repair time may be treated as a random variable, with the specified mean repair time and a variation from the mean which is treated as a random variable. In addition, the times required for the steam output to coast down to zero after a failure or to build up rated power after repairs are completed may be used in the calculation.

Although not included in the illustrative calculation that will be described later, additional refinements (such as major and minor overhaul

periods at different intervals and of different durations and a mixture of partial and complete outages) could be made.

It is assumed that any company contemplating the acquisition of a nuclear reactor to supply process heat would have access to a computer facility. It would develop an appropriate computer simulation of its system and calculate its expected performance before making as large a financial commitment as the purchase of a reactor. The examples described later are intended to be illustrative only. They are less specialized than those a company might employ for analyzing a specific application. Other cost-related factors would, of course, also be taken into consideration.

In such a simulation the function of the computer is to keep a running record of the status of each part of the system and to accumulate the totals for such quantities of interest as energy supplied and hours of operation. No complex calculations are required. The ability of the computer to generate random numbers provides the means for controlling the occurrence of outages in the simulation.

A printout of the input data example problem 3 illustrates the type and amount of data required (see Table 15 in Section 4.3).

3.2 Probabilistic Method

This method can be used to generate various measures of a system's reliability for given inputs of certain reactor and boiler operating characteristics. It does not provide for any details of load adjustment, capacity coastdown, or delay in power recovery when an outage occurs.

For each steam supply (reactor, boiler, etc.) a plot of the probability P that the output will exceed the amount x will resemble the sketch below:

If the unit is assumed to have a constant availability R (as defined in Appendix C) and capacity C , the sketch will resemble:

Here $P(x)$ is the probability that the unit's steam supply is at least x . For two units having availabilities R_1 and R_2 and capacities C_1 and C_2 (with $C_1 > C_2$), the sketch will be:

As further units are added, the sketch takes on the form of a staircase:

If the system load is ℓ , then in the above diagram the probability that the system capacity will be greater than or equal to ℓ is P_ℓ , which will be the aggregate availability of this system.

In terms of the sketches above, the algorithm for adding a unit of capacity C and availability R to the system is (1) multiply each ordinate on the original curve by R and shift it C units to the right, and then (2) calculate $(1 - R)$ times each ordinate on the original curve, and (3) add the results of (1) and (2). The results will be the probability-vs-capacity curve for the augmented system.

In performing step 1, assume $P = 1$ for all negative values of capacity. This subject is discussed in more detail in Ref. 12.

In example case 2 below, there are five equal boilers. If the capacity of each is C and the availability R , the diagram becomes

where the heights of each step in the "staircase" will be recognized as the terms of the binomial theorem expansion of $([1 - R] + R)^5$.

Thus, for example, the probability that the total capacity exceeds C is 1 minus the sum of the first two terms:

$$1 - (1 - R)^5 - 5R(1 - R)^4 .$$

The application of probabilistic methods of analysis varies greatly with the complexity of the system being studied and the degree of detail in the analysis. In illustrative example 1 of Section 4.1, all that is

required to determine overall system availability is the straightforward use of the rules for determining probabilities of statistically independent events. In illustrative example 2 (Section 4.2), either a Monte Carlo or a probabilistic method using hand calculations might be used. Illustrative example 3 (Section 4.3) requires so much computation that a digital computer would be needed. If the system is relatively homogeneous, such that any boiler can supply any load, it can be analyzed by one of the computer programs used for scheduling electric power generation capacity, such as ORSIM.¹³ Such a program will calculate the expected power generation from each unit, the optimal maintenance schedule, the system availability, and other properties. By further manipulations, described in Ref. 14, the method can be used to estimate the probable load to be furnished by each generator (or boiler). However, the input data required are numerous. If the system is not homogeneous and contains units operating at various different temperatures and pressures so that only certain combinations of units can be used together, the probability analysis is likely to become so complicated as to be impractical, and a Monte Carlo analysis will be preferable.

4. APPLICATION OF THE METHODOLOGY

The reliability characteristics used to illustrate the methodology are based on EEI and NRC data cited previously, as well as on other sources. The characteristics are intended to be representative of a range of equipment that might be used to supply industrial steam needs; no attempt was made to model a specific industrial complex.

4.1 Example Problem 1

This example illustrates the use of the probabilistic method to determine the availability of a power supply system that consists of two 3750-MW(t) nuclear reactors that supply 756 kg/s (6×10^6 lb/hr) of steam for industrial uses and up to 1850 MW(e) of electric power to the local power grid. The definition of availability as used in example 1 is given in Appendix C. Either reactor can supply heat to a reboiler, which produces the steam, and either or both reactors can supply steam to a turbine generator. The system is similar to that described in Section A-3 of Appendix A; the configuration is outlined in Fig. 8. Because there are only a few system components to be considered, this example can be calculated by hand. Let the probability that reactor 1 is operational be P_1 , the probability that reactor 2 is operational be P_2 , and the probability that the reboiler is operational be P_R . The plus symbol means that the indicated component is operable, and the minus symbol means that the component is not operable. One can then tabulate the states of the system and their probabilities as follows:

<u>State</u>	<u>Reactor 1</u>	<u>Reactor 2</u>	<u>Reboiler</u>	
A	+	+	+	$P_1 P_2 P_R$
B	+	-	+	$P_1 (1 - P_2) P_R$
C	+	+	-	$P_1 P_2 (1 - P_R)$
D	+	-	-	$P_1 (1 - P_2) (1 - P_R)$
E	-	+	+	$(1 - P_1) P_2 P_R$
F	-	-	+	$(1 - P_1) (1 - P_2) P_R$
G	-	+	-	$(1 - P_1) P_2 (1 - P_R)$
H	-	-	-	$(1 - P_1) (1 - P_2) (1 - P_R)$

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EXAMPLE 1

EXAMPLE 2

Fig. 8. Configurations for examples 1 and 2.

The probability of having industrial steam service when neither reactor is down for scheduled maintenance is the sum of the probabilities for states A, B, and E:

$$(P_1 + P_2 - P_1P_2)P_R .$$

When reactor 1 is on scheduled outage, the probability of having steam is P_2P_R ; when reactor 2 is on scheduled outage, this probability is P_1P_R .

A numerical example of the above relations can be given using representative reliability indices. The reactor availability was taken to be in the range 0.80 to 0.90, which includes the value of 0.866 derived from line 9 of Table 3. The reboiler availability was assumed to range

from 0.94 to 0.98, which straddles the average steam generator availability of 0.954 implied in Fig. 2. For these parameters, the availability of the steam supply ranges from 0.902 to 0.970 when neither reactor is scheduled for overhaul and from 0.752 to 0.882 when a reactor is being overhauled.

The annual average availability is obtained by combining these results with proper time weighting for the period, giving an annual average availability for the system that ranges from 0.86 to 0.95, as shown in Table 12. The improvement in system performance achievable with the addition of one conventional fossil-fired 1700-MW(t) backup boiler that is assumed to have an availability of 0.85 is also shown in the table. Thus,

Table 12. Steam system availability calculated for example 1

<u>Steam supply availability</u>			
Reactor reliability	0.80	0.85	0.90
Reboiler reliability	Neither reactor in refueling outage		
0.94	0.902	0.919	0.931
0.98	0.941	0.958	0.970
	One reactor in refueling outage		
0.94	0.752	0.799	0.846
0.98	0.784	0.833	0.882
	Annual average, if each reactor re-fueling outage is 45 days		
0.94	0.864	0.889	0.909
0.98	0.902	0.927	0.949
	Annual average, two reactors with supplemental fossil boiler (availability = 0.85) and 45 days reactor refueling outage		
0.94	0.980	0.983	0.986
0.98	0.985	0.989	0.992

the average annual availability of the nuclear steam supply system supplemented by one backup boiler ranges from 0.98 to 0.99. The system availability was obtained from the expression

$$R_s = 1 - (1 - R_c)(1 - R_n) ,$$

where R_n is the availability obtained previously for the system powered by two reactors only, R_c is the availability of the conventional boiler, and R_s is the availability of the steam supply system that includes two reactors and one fossil-fired boiler.

4.2 Example Problem 2

This example illustrates the use of the Monte Carlo method to determine the reliability of an industrial power supply system that consists of one PWR rated at 365 MW(t) and five oil- or gas-fired boilers rated at 55 MW(t) each (reliability as used here was defined earlier). The reactor provides steam to generate electricity and, more importantly, to provide heat for an industrial process. The process requires that its working material be kept molten by application of heat; if this material should solidify throughout the system, resumption of system operation would be very expensive. At least 20% of the rated reactor output [i.e., 73 MW(t)] is required to keep the material molten throughout the system, with productive output reduced to zero. Therefore, it is very important that a steaming capacity of at least 73 MW(t) be maintained. It is assumed that when the reactor is out of service, either due to scheduled or forced outage, all available boilers will be used and the plant will operate at partial output. If the reactor is operating at full capacity, the plant will be able to operate at full capacity, and two or three boilers will be kept on standby with the others either cold or in scheduled maintenance. Whether the two boilers on standby will be hot or cold depends on the rate at which the material cools in the absence of a heat supply and the time required to bring the boilers on line. That is, if the material remains liquid for a period equal to or greater than that required to bring the standby boilers up to power, the boilers may be

kept on cold standby; otherwise they must be kept at least partly heated, possibly by circulating some steam through their steam drums. Since at least two boilers are required to operate when the reactor is down, it would seem necessary to have three boilers ready for quick firing, unless experience shows that the boilers start very reliably.

From this discussion, it will be apparent that calculated failure rates will be exceedingly sensitive to the assumptions regarding unit performance. In the second illustrative example the following assumptions were made:

<u>Plant type</u>	<u>PWR</u>	<u>Boiler</u>
Capacity, MW(t)	365	55 each
Mean time between failures, days	40, 70, 100	150
Mean repair time, days	3.4	2
Mean time between overhauls, days	360	360
Mean overhaul time, days	20, 30	30
Coastdown power time, hr	1, 4	3
Buildup power time, hr	6	5

The data for each power source include mean time between failures, mean time required for repair, mean time between scheduled maintenance, and mean time for scheduled maintenance. The PWR parameters used in this sample problem span a range that is pertinent to small reactor applications. The mean time between failure ranges from 40 to 100 days. The value of 82 days for mean time between forced outages (Table 8, line 1) for a ten-year operating history of nuclear units of all sizes falls within the selected span. The mean repair time of 3.4 days was taken from Table 7. Scheduled maintenance is characterized by a mean time between overhauls of 360 days and refueling outage times of 20 and 30 days. Some improvement over reactor experience obtained to date (Table 7) was assumed here to account for the plant improvements achievable in a standardized small reactor. For the fossil-fired boilers, a mean time of 150 days between forced outages was taken from line 1 of Table 10. A mean time of 2 days to complete repairs is consistent with the forced outage rate of Table 10. The scheduled overhaul time for the fossil

units is consistent with the availability data of Table 10. Startup of each steam source was approximated by assuming a linear increase in steam flow from zero to 100% of full power during the indicated "time required to build up power." Shutdowns were treated similarly.

The repair times, overhaul times, and times of failure are random variables whose values are determined by use of a random number generator. The repair times are uniformly distributed over a representative range, namely from 50 to 150% of the values tabulated above. The overhaul times are uniformly distributed between 100 and 130% of the values tabulated above. The mean time between failures is converted to an hourly probability of forced outage. For each operational unit, a random number (from a population uniformly distributed from 0 to 1) is generated every hour. If this is less than or equal to the hourly probability of forced outage, a failure is assumed to have occurred; otherwise, the unit continues in scheduled operation.

As shown by Tables 13 and 14, several different values of mean time between failures and of overhaul times were assumed and results determined for each. It is hoped that the results will give a feel for the level of system reliability to be expected for a reasonable range of reliability inputs.

Two modes of operation were investigated: (1) all units operate when not on scheduled maintenance or forced outage and any power available above 365 MW(t) is used to generate electricity for sale to the local power company; (2) when the reactor is operating, all boilers not scheduled for overhaul or undergoing repairs are kept on cold standby.

When results from Tables 13 and 14 are compared, it will be noted that the greater numbers of forced outages in mode 1 represent fossil-fired boiler outages and that the difference in the values of annual average MW(t) available represents the amount of thermal energy that could be converted to and sold as electric energy. The average MW(t) available for sale as electricity is shown in Table 13.

If the probability method is applied to this example, the operating availability of each boiler — assuming no two are deliberately scheduled

Table 13. Results for example 2 with 33 years of plant operation in mode 1

Mean time between reactor failures, days	40	40	70	70	100	100
Reactor mean overhaul time, days	20	30	20	30	20	30
Hours per year when output <73 MW(t)	0	0	0	0	0	0
Annual average number of forced outages	19.6 ± 4.5 ^a	19.9 ± 3.7	16.7 ± 4.9	16.6 ± 4.5	15.2 ± 4.6	15.3 ± 4.6
Annual average number of reactor forced outages	7.8 ± 2.6	8.2 ± 2.3	4.5 ± 2.1	4.8 ± 2.0	3.7 ± 1.7	3.3 ± 1.4
Annual average MW(t) available	562.6 ± 8.3	550.7 ± 8.4	573.4 ± 8.0	560.0 ± 7.4	576.0 ± 5.7	566.2 ± 5.4
Annual average MW(t) on outage	29.1 ± 8.2	29.7 ± 7.1	18.0 ± 7.5	19.4 ± 6.8	15.2 ± 5.9	13.9 ± 5.1
Annual average MW(t) for sale as electricity	185.1	176.7	172.8	172.0	174.3	166.3
Reactor hours out, annual average	646.4 ± 2.6	660.4 ± 179.8	362.7 ± 177.3	400.9 ± 164.6	299.2 ± 135.3	266.9 ± 117.1
Reactor annual GWhr(t) output	2737 ± 73	2634 ± 71	2831 ± 65	2716 ± 63	2854 ± 44	2767 ± 44
Reactor reliability	0.87 ± 0.00	0.84 ± 0.02	0.90 ± 0.02	0.87 ± 0.02	0.91 ± 0.01	0.88 ± 0.01

^aThe first number is the mean and the second is the standard deviation. Presumably a larger number of years would give more accurate results, but 33 years seem enough to illustrate the method.

Table 14. Results for example 2 with 33 years of plant operation^a in mode 2

Mean time between reactor failures, days	40	40	70	70	100	100
Reactor mean overhaul time, days	20	30	20	30	20	30
Hours per year when output < 73 MW(t)	0	0	0	0	0	0
Annual average number forced outages	11.1 ± 3.5 ^b	11.9 ± 3.7	8.9 ± 2.9	9.0 ± 2.3	7.5 ± 2.3	7.5 ± 2.9
Annual average number reactor outages	7.9 ± 2.9	8.2 ± 2.2	5.4 ± 2.1	5.0 ± 1.9	3.7 ± 1.9	3.6 ± 2.2
Annual average MW(t) available	377.5 ± 14.3	374.0 ± 12.8	390.6 ± 21.1	387.0 ± 20.3	402.3 ± 19.2	399.9 ± 21.9
Annual average MW(t) on outage	26.7 ± 9.8	27.5 ± 7.4	18.3 ± 6.5	17.8 ± 6.1	12.9 ± 6.1	12.9 ± 7.2
Reactor hours out, annual average	639.3 ± 237.4	657.8 ± 180.1	429.0 ± 165.2	415.4 ± 150.7	297.4 ± 153.9	298.6 ± 182.1
Reactor annual GWhr(t) output	2736 ± 86	2631 ± 63	2810 ± 54	2715 ± 54	2858 ± 58	2763 ± 62
Reactor availability	0.37 ± 0.03	0.84 ± 0.02	0.90 ± 0.02	0.87 ± 0.02	0.91 ± 0.02	0.88 ± 0.02

^aIn this mode of operation no electric power is generated for sale.

^bMean ± standard deviation.

for overhaul at the same time — is

$$\begin{aligned}
 R &= \frac{\text{mean time between failures}}{\text{mean time between failures} + \text{repair time}} \\
 &\times \frac{\text{mean time between overhauls}}{\text{mean time between overhauls} + \text{overhaul time}} \\
 &= \left(\frac{\text{fraction of time unit can}}{\text{run when scheduled to do so}} \right) \times \left(\frac{\text{fraction of time not}}{\text{scheduled for outage}} \right).
 \end{aligned}$$

Since the minimum requirement of 73 MW(t) to prevent solidification is between the capacity of one and two boilers, the probability of having 73 MW(t) available from the boilers is (adapted from Section 3.2)

$$P = 1 - (1 - R)^5 - 5R(1 - R)^4 = 1 - (1 + 4R)(1 - R)^4 .$$

Therefore, if the mean time between boiler failures is 150 days, repair time is 2 days, mean time between overhauls is 360 days, and the overhaul time is 30 days, one obtains

$$R = \frac{150}{152} \times \frac{360}{390} = 0.91093$$

and

$$P = 1 - (1 + 4 \times 0.91093)(1 - 0.91093)^4 = 0.999681 .$$

The high probability that 73 MW(t) will be available from the backup boilers helps explain why the Monte Carlo calculation never showed a failure.

4.3 Example Problem 3

In this example, the Monte Carlo method is used to determine the reliability of a steam supply system serving a combined refinery and chemical plant — somewhat similar to refinery No. 1 of Ref. 2. That plant plan has been simplified for this example, however, in that any boiler is assumed to be able to supply any load and waste heat recovery boilers have been omitted. The example illustrates the case of a larger

number of units than in examples 1 and 2. A small reactor [365 MW(t)] is to supply about one-fourth of the industrial plant's 1400-MW(t) system load. The 19 existing fossil-fired boilers [total capacity 1559 MW(t)] are to be retained, with the excess on standby.

The composition and characteristics of the system are shown in Table 15, which is a copy of a part of the computer output; Fig. 9 outlines the plant configuration. The system load was assumed uniform at 1400 MW(t), but a 20% reduction [280 MW(t)] was assumed allowable before an "outage" occurred. This reduction is derived from data provided in line F of Table 2. Reliability parameters for the nuclear unit were selected on the same basis as for example 2, except that the scheduled reactor outage duration was increased to 45 days. Operating experience is reflected in parameters shown for the fossil-fired units.

Results for 14 years of operation are shown in Table 16 for three values of mean time between reactor failures. Some results include large standard deviations, indicating that a longer operating history would have to be examined if more precise results are sought. The average number of hours per year when thermal output decreased below the

Fig. 9. Plant configuration, example 3.

Table 15. Characteristics of steam supply plants^a

Plant number	1	2	3	4	5	6	7	8	9	10
Plant name	Reactor	Boiler	Boiler	Boiler	Boiler	Boiler	Boiler	Boiler	Boiler	Boiler
Plant type	1	2	2	2	2	2	2	2	2	2
Capacity, MW(t)	365.0	160.0	160.0	160.0	160.0	175.0	112.0	80.0	80.0	80.0
Days to first overhaul	1	46	106	166	226	286	76	136	196	256
Mean days between failures	40,70,100	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
Mean repair time, days	3.4	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Mean days between overhauls	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0
Overhaul time, days	45.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Minimum standby capacity, MW(t)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Probability of partial shutdown	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coastdown power time, hr	1.000	3.000	3.000	3.000	3.000	3.000	3.000	3.000	3.000	3.000
Buildup power time, hr	6.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000
Probability of forced outage	0.001042	0.001263	0.001263	0.001263	0.001263	0.001263	0.001263	0.001263	0.001263	0.001263

Plant number	11	12	13	14	15	16	17	18	19
Plant name	Boiler	Boiler	Boiler	Boiler	Boiler	Boiler	Boiler	Boiler	Boiler
Plant type	2	2	2	2	2	2	2	2	2
Capacity, MW(t)	80.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0
Days to first overhaul	316	1	46	91	136	181	236	271	316
Mean days between failures	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
Mean repair time, days	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Mean days between overhauls	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0
Overhaul time, days	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Minimum standby capacity, MW(t)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Probability of partial shutdown	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coastdown power time, hr	3.000	3.000	3.000	3.000	3.000	3.000	3.000	3.000	3.000
Buildup power time, hr	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000
Probability of forced outage	0.001263	0.001263	0.001263	0.001263	0.001263	0.001263	0.001263	0.001263	0.001263

^aTotal system capacity = 1844.0 MW(t); load reduction on outage = 280.0.

Table 16. Results for 14-year history Monte Carlo reliability analysis (example 3)

	Mean time between reactor outages (days)		
	40	70	100
Average annual hours of shortage	101.6 $\pm$ 48.9 ^a	80.3 $\pm$ 42.1	100.5 $\pm$ 65.5
Average annual number of forced outages	181.1 $\pm$ 8.0	178.1 $\pm$ 8.3	176.3 $\pm$ 8.6
Average capacity available	1551.7 $\pm$ 7.0	1565.2 $\pm$ 10.9	1563.0 $\pm$ 9.2
Average capacity loss due to forced outages	99.9 $\pm$ 6.8	89.2 $\pm$ 9.2	87.7 $\pm$ 7.0
Average reactor output, GWhr(t)	2479.0 $\pm$ 51.0	2579.0 $\pm$ 77.0	2567.0 $\pm$ 77.0
Average annual reactor outages	7.8 $\pm$ 1.7	4.9 $\pm$ 2.4	4.4 $\pm$ 1.9
Reactor availability	0.77 $\pm$ 0.01	0.81 $\pm$ 0.02	0.80 $\pm$ 0.02

^aNumbers represent mean value $\pm$ standard deviation.

acceptable reduced value of 1120 MW(t) ranged on the average from 80 to 102. The standard deviations and these quantities are so large as to mask the sensitivity to the reactor failure rate. The number of occurrences of individual unit forced outages averaged between 176 and 181 per year. The average capacity loss due to forced outages amounted to 6 to 7%. Reactor availability ranged from 0.77 to 0.81, which is lower than what is believed achievable from fully developed plants.

For comparison, Table 17 shows reliability characteristics calculated for the steam supply system considered in example 3, but before addition of the reactor. Comparing Table 16 with Table 17, it can be seen that this average capacity loss due to forced outages is increased by the presence of the reactor — this is primarily because the reactor is more than twice the size of the largest fossil-fired boiler and thus each reactor failure removes a large block of capacity. The annual hours of shortages when the steam system capacity falls below 1120 MW(t) is

Table 17. Results for 14-year history Monte Carlo
reliability analysis for fossil-fired-only case

Average annual hours of shortage ^a	938.1 ± 105.7
Average annual number of forced outages	173.3 ± 11.1
Average capacity available, MW(t)	1266.1 ± 4.9
Average capacity loss due to forced outage ^b	73.2 ± 4.6

^aBelow the minimum allowable system load of 1120 MW(t).

^bCapacity of forced out units.

much less when the reactor is included, and overall system performance is enhanced by the reactor. Different results would have been obtained if other outage rates and power coastdown or buildup times had been used. The calculation does, however, illustrate how reactor and boiler reliability data can be used to predict their combined performance and to develop some feel for the effect of various unit characteristics on system reliability.

5. SUMMARY AND CONCLUSIONS

Reliability data obtained from reactor operating experience provide a suitable base for estimating the reliability for industrial steam supplied from nuclear reactors. For current-generation large industrial reactors, the reliability data obtained from central station size reactors appear particularly useful. Some care must be taken in using historical data to analyze industrial steam applications. For example, data obtained from central station reactor operations that are to be applied to the analysis of nuclear industrial steam systems may have to be corrected to remove the contribution of power-conversion equipment to unreliability. The state of development of the reactor system under consideration needs to be considered in predicting reliability. The operating experience with large [~ 3700 -MW(t)] power reactors was obtained from plants built according to new designs. Due to schedule constraints, follow-on units generally have been built in accordance with the initial design and thus do not incorporate significant re-engineering that reflects the operating experience that may have been gained with preceding units. This situation will improve as further experience is obtained and plant designs become more fully developed. Plant performance will therefore quite likely improve with time, and this aspect needs to be considered in projecting future reactor reliability.

Relatively little experience has been obtained with smaller reactors [~ 300 to 400 MW(t)] and none for second-of-a-kind designs. It seems plausible that the availability of a small reactor built to a standardized design would be superior. A small reactor should experience fewer failures since it comprises fewer components; in addition, refueling requires less time since fewer fuel elements need to be handled. Maintenance operations requiring plant cooldown and heatup also will be shorter because components will be less massive, thus permitting shorter warmup and cooldown periods.

The calculational methods developed during the study to determine the reliability of industrial energy supply systems powered by nuclear and fossil-fired units are suitable for analyzing systems of some complexity. The results obtained show that overall reliability of an industrial steam supply system depends on a multiplicity of system characteristics. Of

prime importance are the number and capacity of the various power sources, along with assorted operating characteristics such as outage rates, repair times, and coastdown and startup times. The operating mode of each unit (whether shutdown, hot standby, or on line) can also have a significant effect on system reliability. The nature of the industrial operation, such as allowable reductions in the system load and allowable load coastdown rates, also affect reliability requirements. Thus, it becomes apparent that the reliability of industrial energy supply systems can best be analyzed on a case-by-case basis.

The performance parameters used in the example problems of Section 4 were selected to cover a fairly broad range of reasonable values, and the following conclusions can be drawn from the results.

The results of example 1 give some indication of the availability of a steam supply system fed via a reboiler that in turn is supplied by two reactors, each with sufficient capacity to carry the entire steam load. For this configuration, the steam system availability ranges from 0.86 to 0.95. Tables 1 and 2, which summarize data obtained in chemical plants and petroleum refineries, show that a sizable fraction of these plants have operated with steam supply availabilities that fall into or below the range of 0.86 to 0.95 cited above. Thus, the two reactor schemes examined above might prove adequate for some industrial applications. The addition of a fossil-fired backup boiler would increase steam availability up to 0.98 to 0.99, values that are appropriate to industrial processes with more stringent requirements.

The problem treated in example 2 illustrates application of a small industrial reactor as a replacement for an existing industrial steam supply system. Five boilers that were part of the existing facility provide backup steam. For the particular constraints chosen, quite sizable variations in reactor outage rate have minor influence on overall steam reliability. Moderate gains in steam reliability are achieved if the fossil units are kept on line to supply power to a sheddable electric load. Adequate reliability is maintained under all the conditions examined, and it is clear that multiple fossil-fired units can provide quite adequate backup. This option is particularly attractive for reactor applications at sites

that already have fossil-fired boilers but where operation must be curtailed because fuel has become scarce or costly. Under these circumstances, the chargeable capital costs for providing backup boilers may be moderate. The cost of fuel consumed is also likely to be a minor factor since fossil fuels would be used to produce only a small fraction of the total amount of energy consumed.

Example 3 showed that the Monte Carlo method can readily handle fairly complex systems that include many variables. Here, a single reactor was assumed to replace about one-fourth of the capacity of an existing fossil-fired industrial steam supply system. For the particular case studied, moderate changes in reactor failure rate had only a minor impact on the overall performance of the steam supply system. Addition of the reactor system significantly reduced the annual hours of steam shortages.

Appendix A

A. NUCLEAR SYSTEMS FOR INDUSTRIAL PROCESS ENERGY

A partial survey of the potential market for nuclear industrial energy sources indicates there are major possibilities for process steam applications. It is estimated⁹ that steam at temperatures and pressures available from current-generation light-water reactors (LWRs) could (functionally) replace about 85% of the steam now generated with fossil fuels in the industries surveyed.

The Midland reactor plant, which is now being built for Consumers Power Company to generate electrical power and furnish process energy (so-called dual-purpose use) to the adjacent Dow Chemical plant, is an example of this approach applied at a very large industrial plant. Since the start of the Midland project, fossil fuels have become increasingly scarce and costly, and thus the relative position of nuclear power economics has improved. As a result, it is now believed that dual-purpose reactor plants (located at sites that allow economical construction of process steam lines) can provide competitively priced process heat even to industries located up to 10 miles from a reactor station. Thus, it may be practical to furnish process steam to a cluster of industrial plants with an aggregate electrical and process energy demand that warrants operation of a centrally located dual-purpose reactor station.

Another solution would be to use small industrial nuclear reactors [300 to 500 MW(t)] which would match the load demand of single large energy user plants, thus avoiding the institutional problems arising from use of a single utility-owned plant to serve a number of industries. Furthermore, the planning and construction of small reactors could quite likely be accomplished within about two-thirds of the time required for large central station reactors.

In order to provide background for the reader, some of the reactor systems considered for industrial applications will be briefly described. Two of these are LWR designs, based on current technology, that would be suitable for near-term applications. Two others are advanced high-temperature, gas-cooled, pebble-bed reactor concepts that probably would not be ready for commercial introduction until the 1990s.

A.1 Small Pressurized-Water Reactors

One of the near-term small nuclear reactors available for industrial applications is based on a 313-MW(t) ship propulsion reactor already developed for the U.S. Maritime Administration. Work on the Consolidated Nuclear Steam Generator (CNSG) for nuclear ship propulsion has been under way at Babcock & Wilcox Company¹⁵ since 1959. Some of the unique features of the plant design, including the once-through steam generator housed within the reactor vessel, have already been demonstrated in the Federal German Republic nuclear ship "Otto Hahn," which has operated successfully since 1969. The U.S. Maritime Commission has continued to sponsor work in the areas of design, testing, and evaluation of the CNSG concept, and current efforts are directed toward icebreaker propulsion.

The CNSG design is essentially based on current technology, and relatively little development would be required for process heat applications for up to 365 MW(t). Major reactor parameters are shown in Table A-1.

Table A-1. Reactor parameters

Size	365 MW(t)
System pressure	15,510 kPa (2250 psia)
Core inlet temperature	300°C (571.6°F)
Core outlet temperature	319°C (606.4°F)
Maximum thermal output (100%)	53 kW/m (16.08 kW/ft)
Boiler feedwater temperature	204°C (400°F)
Total steam-generator flow	189 kg/s (1.50×10^6 lb/hr)
Steam side design temperature	343°C (650°F)
Steam side operating temperature	281°C (548°F)
Steam side operating pressure	4830 kPa (700 psia)
Process steam flow	183 kg/s (1.45×10^6 lb/hr)
Process steam temperature	250°C (483°F)
Process steam pressure	4000 kPa (580 psia)
Process condensate temperature	121°C (250°F)

The reactor can be utilized to produce about 1.45×10^6 lb/hr of process steam or about 110 MW(e), or a combination of both. Process steam would be produced in a reboiler to provide further isolation between the primary coolant and the industrial processes. The capital cost for a process-steam-producing plant (without interest during construction) amounts to about 100 million 1975 dollars, excluding escalation and interest during construction. Levelized process steam costs¹⁶ range from \$2.60 to \$3.40 (in 1975 dollars) for a variation in the capital fixed charge rate from 15 to 22%.

A.2 Small Pebble-Bed Reactor

Applications of small, gas-cooled, pebble-bed reactors for industrial energy were evaluated in a study¹⁷ by the General Electric Company under contract to ORNL. This technology is based on the 40-MW(t) AVR pebble-bed reactor in Germany that has operated successfully with helium reactor exit temperatures up to 950°C (1742°F) with on-line refueling. The study evaluated three distinct pebble-bed reactor concepts designed to furnish process energy to industry: (1) a plant for the production of process steam only, (2) a plant for the production of synthetic gas through methane reforming, and (3) a plant for generating electricity with a helium-driven turbogenerator in addition to producing process steam. The range of power level [200–1000 MW(t)] is compatible with the energy requirements of large chemical, petroleum refining, and primary metals plants.

A.2.1 Process Steam Plant

The reactor consists of a cylindrical prestressed concrete pressure vessel containing a graphite reflector assembly, and the core consists of a bed of spherical graphite balls containing the fuel. Fuel is added continuously at the top and removed at the bottom after a residency time of approximately 4.5 years. The reactor coolant, helium gas at about 4000 kPa (580 psia), flows downward in the same direction as the fuel flow. The reactor delivers 186 kg/s (1.48×10^6 lb/hr) of helium at an exit temperature of 760°C (1400°F). This gas is circulated through three

steam generators to produce a total of 171 kg/s (1.36×10^6 lb/hr) of superheated steam at 510°C (950°F) and 5860 kPa (850 psia). The steam generators include double tubes and double tubesheets in order to provide a buffer region between the radioactive primary coolant and the process steam. Attractive features of this design include on-line refueling (resulting in a larger plant factor) and elevated steam conditions that are directly compatible with steam utilization in current industrial plants.

A considerable amount of component development is necessary and a prototype plant would have to be built for the introduction of small commercial pebble-bed reactors. Assuming the project starts in 1977, prototype plant startup could take place by 1987, and commercial plant startup around 1990.

Levelized process steam costs for a 365-MW(t) reactor are about 28% higher than those for the 365-MW(t) PWR discussed previously, thus reflecting the higher capital cost of the pebble-bed reactor. These costs do not reflect the potentially greater value of 510°C (950°F) steam from the pebble-bed reactor relative to steam of only 250°C (483°F) from the LWR.

A.2.2 Nuclear Process Heat Plant

The purpose of this plant is to produce reducing gas from the reaction $\text{CH}_4 + \text{H}_2\text{O} + \text{heat} \rightarrow \text{CO} + 3\text{H}_2$. The energy required to make the reaction proceed is supplied by the reactor, as opposed to use of chemical energy, which is the present industrial method. Since natural gas is used both as feed stock and as heating fuel, the use of nuclear energy essentially doubles the yield of hydrogen from a given amount of natural gas. The product gas — a mixture of unreacted methane, carbon monoxide, carbon dioxide, hydrogen, and steam — may be treated in many ways as dictated by its ultimate use. These treatments may range from the production of essentially pure hydrogen to the use of the gas mixture in a chemical heat pipe to supply energy at a distant location via the reverse reaction.

A key difference between this concept and the process steam design is the elevated operating temperature of the reformer plant. The reactor helium exit temperature of 950°C (1742°F) places very stringent limitations on selection of materials. Since metals are currently not ASME qualified for use above 815°C (1500°F), much proof testing will be required to derive the needed pressure vessel code approvals.

The reactor power of 500 MW(t) is used to generate 27.9 kg/s (455,000 lb/hr) of steam at 510°C (950°F) for injection into a double-tube steam reformer. For a methane consumption rate of 8.6 kg/s (6800 lb/hr), reducing gas is produced at a rate of 36.5 kg/s (290,000 lb/hr) at 600°C (1110°F). Levelized costs for the energy produced by the reactor amount to 625¢/10⁶ kJ (659¢/10⁶ Btu). The high energy cost is partly due to the relatively small power output. By comparison, energy costs for large [3000-MW(t)] pebble-bed reactor application were estimated at only 310¢/10⁶ kJ (330¢/10⁶ Btu) in a recent assessment¹⁸ of VHTR technology. Thus, application of a small pebble-bed reactor for reforming steam may be advantageous, primarily if institutional, geographic, or other considerations rule out product gas supplied by pipeline from a large central station-size unit.

A.3 Dual-Purpose Station Powered by Two Large PWRs

The application¹⁹ of large PWRs for industrial energy is illustrated in this description of a reactor plant designed to produce electricity for a utility grid and process steam for piping to nearby industries. The reactor station consists of two current-type 3750-MW(t) PWRs and a power conversion system. Prime steam flow amounts to 2000 kg/s (16×10^6 lb/hr) at 318°C (603°F). Process steam is furnished from a reboiler rather than from the prime steam generators since, in many applications, an intermediate heat transport system may be required to prevent the transfer of contaminants between the reactor systems and the industrial processes. For the base case, all the steam from one reactor is supplied to a 1200-MW(e) turbogenerator, while steam from the second is split 54/46 between a 650-MW(e) turbogenerator and a reboiler capable of generating 6×10^6 lb/hr of process steam at 5860 kPa (850 psia) and 274°C

(525°F). The capacity of the reboiler and the smaller of the turbogenerators could be varied to match different process steam flow rate requirements. For applications requiring lower process steam pressure and temperature, the smaller generator could be driven by an extraction or back-pressure turbine, with the extraction or exhaust steam going to a reboiler producing steam at more moderate conditions.

For the base case, prime steam at about 317°C (603°F) and 7400 kPa (1075 psia) is supplied to the tube side of the reboilers to generate process steam at 274°C (525°F) and 5860 kPa (850 psia) on the shell side. Steam is generated at a rate of 755 kg/s (6×10^6 lb/hr) in several high-pressure reboiler units of about 63 kg/s (500,000 lb/hr) capacity each. One backup unit is needed to maintain full steam flow during reboiling maintenance. Associated with the reboilers are feedwater heaters that heat the condensate from the industrial processes before it is returned to the reboilers. It is anticipated that the reboilers and feedwater heaters would be located at the reactor station so that process steam can be furnished conveniently to a number of dispersed industrial users.

Insulated steel pipes convey the process steam from the reboilers located at the reactor station to the industrial sites utilizing the steam. Assuming pressure drops of 43 to 51 kPa/km (10 to 12 psi/mile), a 0.71-m-diam (28-in.) pipe could convey 126 kg/s (1×10^6 lb/hr) of 5860 kPa (abs) (850 psia) steam; a flow of 252 kg/s (2×10^6 lb/hr) requires a diameter of about 0.91 m (36 in.). For steam at 1380 kPa (abs) (200 psia), flows of 126 kg/s (1×10^6 lb/hr) and 252 kg/s (2×10^6 lb/hr) require pipes of 0.91 m (36 in.) and 1.22 m (48 in.) diameter, respectively.

The required revenue from process steam was calculated by taking the difference between the annual cost and the annual revenue from the sale of electricity. The total annual production cost for the 1200-MW(e) unit is \$107.8 million, corresponding to 12.8 mills/kWhr, all expressed in late 1974 dollars. This value is not affected by the dual-purpose nature of the station and is therefore considered a fair price for computing the revenue obtained from the sale of electricity. This income amounts to \$58.4 million per year for the 650-MW(e) unit, leaving \$33.3

million to be obtained from the sale of steam. This is equivalent to a cost of $77\text{¢}/10^6 \text{ kJ}$ ($81\text{¢}/10^6 \text{ Btu}$) of reactor prime steam.

A $15\text{¢}/10^6 \text{ kJ}$ ($15\text{¢}/10^6 \text{ Btu}$) cost increment is attributable to the reboiler plant. Total cost of the 5860-kPa (abs) (850-psia) 274°C (525°F) process steam therefore amounts to 92¢ per million kJ (97¢ per million Btu) at the reboiler.

The cost of process steam at lower temperature was derived from cost data²⁰ for dual-purpose LWRs. Table A-2 combines the steam production and transport costs, giving the cost for 1380-, 3450-, and 5860-kPa (abs) (200-, 500-, and 850-psia) saturated steam delivered to industrial users located at sites up to 16 km (10 miles) from the power station. The cost of delivered process steam ranges from 78 to $191\text{¢}/\text{million kJ}$ (82 to $201\text{¢}/10^6 \text{ Btu}$), depending on the particular steam pressure, flow rate, and conveyance distance.

Table A-2. Cost ($\text{¢}/10^6 \text{ kJ}$) of process steam as a function of conveyance distance^a

Steam flow, kg/s (lb/hr)	126 (1,000,000)			250 (2,000,000)		
	1380 (200)	3450 (500)	5860 (850)	1380 (200)	3450 (500)	5860 (200)
Pipeline length [km (miles)]						
0 (0)	78	88	92	78	88	92
4.8 (3.0)	101	114	120	96	110	117
9.6 (6.0)	126	139	151	119	132	142
16.1 (10.0)	156	173	189	146	161	176

^aThe tabulated values do not include the cost of a new backup steam supply. Provision of an oil-fired standby steam supply capable of providing 25% of normal flow would increase the cost of 1380-kPa process steam by about $13\text{¢}/\text{million kJ}$. The corresponding values for 3450- and 5860-kPa steam are 15 and 18¢ , respectively. To convert to $\text{¢}/10^6 \text{ Btu}$, multiply by 1.055.

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Appendix B

GLOSSARY FROM OPERATING UNITS STATUS REPORT,
LICENSED OPERATING REACTORS³

Available	Status of unit or major piece of equipment which is capable of service whether or not it is actually in service.
Available hours	Service hours + reserve shutdown hours.
Date of commercial operation	Date unit declared by utility-owner to be available for the regular production of electricity; usually related to satisfactory completion of qualification tests as specified in the purchase contract and to accounting policies and practices of utility.
Design electrical rating, MW(e)	Nominal net electrical output of the unit specified by the utility and used for the purpose of plant design.
Gross electrical energy generated	Gross electrical power times gross hours in reporting period.
Gross electrical power MW(e)	Electrical output of the unit measured at the output terminals of the turbine generator.
Gross hours in reporting period	24 times number days in month.
Gross thermal power	Thermal output of the nuclear steam supply system expressed in megawatts.
Gross thermal energy generated	Gross thermal power times gross hours in reporting period.
Hours generator on line (service hours)	Total number of hours unit operated with breakers closed to station bus.
Licensed or currently authorized power level	Maximum thermal power of the reactor, expressed in megawatts; authorized by the NRC.
Maximum dependable capacity	Dependable main-unit capacity (net), winter or summer, whichever is smaller. The maximum dependable capacity often differs from the unit Design Electrical Rating because the unit efficiency may vary during the year due to cooling water temperature variations. The Net Maximum Dependable Capacity is the gross electrical output, as measured at the output terminals of the turbine generator during the most restrictive seasonal conditions (usually summer), less the normal station service loads. The Maximum Dependable Capacity can be used to compute the unit capacity factor.

Net electrical energy generated (output)	Gross electrical output of the unit measured at the output terminals of the turbine generator minus the normal station service loads.
Operating availability	See Reactor Availability Factor.
Period hours	See Gross Hours in Reporting Period.
Reactor availability factor (aka. operating availability)	$\frac{\text{Reactor available hours}}{\text{Gross hours in reporting period}} \times 100$
Reactor service factor	$\frac{\text{Hours reactor critical}}{\text{Gross hours in reporting period}} \times 100$
Reporting period	Calendar month for which data are presented, unless otherwise specified.
Reserve shutdown	Removal of unit from service for economic or similar reasons, but available for operation.
Reserve shutdown hours	Reserve shutdown times number of hours.
Restricted power level MW(e) - net	Maximum net electrical generation to which the unit is restricted because of the malfunction of equipment, other conditions that may exist, or a direction by NRC.
Scheduled outage	Planned removal of a unit from service for refueling, inspection, and/or general overhaul of one or more major equipment groups.
Service hours	See Hours Generator On Line.
Startup and power ascension test phase	Period following initial criticality during which the unit is tested at successively higher levels, culminating with operation at full power for a sustained period and completion of warranty runs. Following this phase, the unit is generally considered by the utility to be available for commercial operation.
Unit availability factor	$\frac{\text{Unit available hours}}{\text{Gross hours in reporting period}} \times 100$
Unit capacity factor (using MDC)	$\frac{\text{Total net generation (MWhr)}}{\text{Period hours} \times \text{max. depend. capacity}}$
Unit capacity factor [using design MW(e)]	$\frac{\text{Total net generation (MWhr)}}{\text{Period hours} \times \text{design elec. rating}}$
Unit forced outage rate	$\frac{\text{Forced outage hours}}{\text{Hr generator on line} + \text{forced outage hr}} \times 100$
Unit service factor	$\frac{\text{Hours generator on line (service hours)}}{\text{Period hours}} \times 100$

NOTE: Do not include reserve shutdown hours in calculation.

Appendix C

DEFINITIONS OF TERMS USED IN THE ANNUAL REPORTS
ON EQUIPMENT AVAILABILITY PUBLISHED BY EEI⁶

A. EQUIPMENT DEFINITIONS

1. Nonheader unit	Unit in which a single boiler is connected solely and independently to a given turbine generator.
2. Header unit	Unit in which the turbine generator is not solely and independently connected to single boiler.
3. Major equipment	Major group of equipment within a unit, such as: boiler, reactor, generator, steam turbine, condenser.
4. Component	Part within a "major equipment" group, such as superheater tube, governor, buckets, boiler feed pump.
5. Maximum dependable capacity (MDC)	The dependable main-unit capacity winter or summer, whichever is smaller.

B. OPERATION AND OUTAGE DEFINITIONS

1. Available	The status of a unit or major piece of equipment which is capable of service, whether or not it is actually in service.
2. Base loading	When a unit is generally run at or near rated output.
3. Cranking loading	When a unit is generally shut down on standby for auxiliary power during emergency.
4. Cycling loading	When a unit is generally run but at a load which varies widely with system demand.
5. Economy outage	(See Reserve Shutdown).
6. Forced outage	The occurrence of a component failure or other condition which requires that the unit be removed from service immediately or up to and including the very next weekend.
7. Forced partial outage	The occurrence of a component failure or other condition which requires that the load on the unit be reduced 2% or more immediately or up to and including the very next weekend.
8. Maintenance outage	The removal of a unit from service to perform work on specific components which could have been postponed past the very next weekend. This is work done to prevent a potential forced outage and which could not be postponed from season to season.

9. Noncurtailing equipment outage	The removal of a specific component from service for repair, which causes no reduction in unit load or a reduction of less than 2%.
10. Nonoperating equipment test	A scheduled test or required operation of a backup system which is not normally operating.
11. Outage cause	A component failure, preventive maintenance, or other condition which requires that the unit or a component be taken out of service or run at reduced capacity.
12. Peak loading	When a unit is generally shut down and is run only during high demand periods.
13. Planned outage	The removal of a unit from service for inspection and/or general overhaul of one or more major equipment groups. This is work which is usually scheduled well in advance (e.g., annual boiler overhaul, five-year turbine overhaul).
14. Reserve shutdown	The removal of a unit from service for economy or similar reasons. This status continues as long as the unit is out but available for operation.
15. Scheduled partial outage	The occurrence of a component failure or other condition which requires that the load on the unit be reduced 2% or more but where this reduction could be postponed past the very next weekend.
16. Unavailable	The status of any major piece of equipment which renders it inoperable because of the failure of a component, work being performed or other adverse condition.

C. TIME DEFINITIONS

1. Available hours (AH)	The time in hours during which a unit or major equipment is available; $SH + RSH$.
2. Demand period	The time interval each day which is the period of maximum demand on a particular system.
3. Economy outage hours (see Reserve shutdown hours) (TEOH)	The theoretical value of economy outage hours (TEOH) is the difference between available hours and service hours. If the TEOH differs by less than 1% with the economy outage hours reported at the end of the year, they are considered equal and flagged with code 1. If the difference is

more than 1%, but less than 10%, they are flagged with code 3; but the reported economy outage hours are still used. However, if the difference is greater than 10%, the calculated value TEOH is used, and code 2 is a flag that economy outage hours have been derived.

4. Forced outage hours (FOH) The time in hours during which a unit or major equipment was unavailable due to a forced outage.
5. Forced partial outage hours (FPOH) The time in hours during which a unit or major equipment is unavailable for full load due to a forced partial outage.
6. Hours waiting (HW) That portion of time for any outage during which no work could be performed. This includes time for cooling down equipment and shipment of parts. This is time that could not be affected by a change in work schedule or the number of men worked.
7. Maintenance outage hours (MOH) The time in hours during which a unit or major equipment is unavailable due to a maintenance outage.
8. Period hours (PH) The clock hours in the period under consideration (generally one year).
9. Planned outage hours (POH) The time in hours during which a unit or major equipment is unavailable due to a planned outage.
10. Reserve shutdown hours (RSH) Reserve shutdown duration in hours.
11. Scheduled partial outage hours (SPOH) The time in hours during which a unit or major equipment is unavailable for full load due to a scheduled partial outage.
12. Service hours (SH) The total number of hours the unit was actually operated with breakers closed to the station bus.
13. Unit years (UY) This term is the common denominator used to normalize data from units of the same type with different lengths of service. The following example contains 20 UY of experience from 4 units.

Unit	A	B	C	D	4
Years in service	8	3	7	2	20
14. Work (manhours worked) (MH) The total number of manhours worked on or off site to accomplish repairs.

D. EQUATIONS

1. Average forced outage duration (Summation of FOH)/(number of forced outages).
2. Capacity factor $[(\text{Total gross generation in MWhr})/(\text{PH} \times \text{maximum dependable capacity})] \times 100.$
3. Component outage severity index The average number of forced outage hours of a specific component per incident.
4. Equivalent forced outage rate (EFOR) (for each forced partial outage, and equivalent full load outage duration is calculated to include the effect of partial as well as full forced outages on the forced outage rate) EFOR is calculated as follows:

$$\text{TE} = \text{FPOH} (\text{CR}/\text{CF})$$
 where:
 TE is equivalent forced outage time,
 CR is size of reduction or derating from full load,
 CF is rated capacity.
 Then:

$$\text{EFOR} = 100 \times [\text{TF} + \text{TES})/(\text{TO} + \text{TF} + \text{TAS} + \text{TPS})],$$
 where
 TF is total full forced outage time,
 TO is total operation time at 100% capability,
 TAS is sum of actual forced partial outage times,
 TES is sum of equivalent forced outage times,
 TPS is sum of equivalent scheduled partial operating times.
5. Forced outage incident rate $[(\text{Forced incidents})/(\text{forced} + \text{maintenance} + \text{planned incidents})] \times 100.$
6. Forced outage rate $[\text{FOH}/(\text{SH} + \text{FOH})] \times 100.$
7. Scheduled outage rate $[\text{SOH}/(\text{SH} + \text{SOH})] \times 100.$
8. Forced outage ratio $[\text{FOH}/(\text{total unavailable hours})] \times 100.$
9. Operating availability $[\text{AH}/\text{PH}] \times 100.$
10. Equivalent availability $[\text{SH} - (\text{EFOH} + \text{ESOH})]/\text{PH}.$
11. Output factor $(\text{Total gross generation in MWhr}) \times 100/(\text{SH} \times \text{MDC})$
12. Service factor $[\text{SH}/\text{PH}] \times 100.$

13. Relative mechanical
availability (RMA)

RMA is a form of operating availability adjusted to show relative effort. The prime assumption is that most outage time is affected by work schedules and crew sizes. RMA uses an adjusted outage time (AOT) based on effort. Manhours worked is a measure of effort which is reasonably independent of work schedules and crew sizes. Manhours worked (MH) divided by a standard work force (SWF) gives a derived time worked based on effort. If we assume a round-the-clock schedule, then this derived time worked is almost a derived outage time based on effort. The difference is the amount of outage time which is independent of effort called Hours Waiting (HW). See Appendix C-6.* An arbitrary assumption of ten men for the standard work force gives:

$$AOT = HW + MH/10$$

Then substituting AOT for outage time in the equation for operating availability gives:

$$\begin{aligned} RMA &= [(PH - AOT)/PH] \times 100 \\ &= \{[PH - (HW + MH/10)]/PH\} \times 100 \end{aligned}$$

Reporting these data is optional.

*Refers to Ref. 3.

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Appendix D

DIFFERENCES IN DEFINITIONS USED IN
NRC AND EEI DATA BASES⁶

EEI and NRC definitions of availability and capacity factors are similar, but recognizable differences exist which must be evaluated for accurate comparisons. Operating availability as defined by EEI is

$$\frac{\text{Available hours} \times 100}{\text{Period hours}},$$

where available hours = the time in hours during which a unit or major equipment is available. This includes both service hours with breakers to the system but closed and reserve shutdown hours during which the unit is shut down but available for service. Period hours = the clock hours in the period under consideration.

As defined by the NRC, unit availability factor is

$$\frac{\text{Time generator was on line (hr)} \times 100}{\text{Time in the period (hr)}},$$

where time generator was on line = only the time the generator was supplying power to the system. Period hours = the clock hours in the period under consideration.

The EEI definition will give a higher availability factor since it takes into account time the unit could have been used but was not. The NRC value, which does not take reserve shutdown hours into account, typically yields availabilities which are 1 to 3 percentage points lower than the EEI values.

Unit capacity factor as defined by both EEI and NRC is "the quotient of the actual net electrical energy output produced by the unit in a given period, divided by the maximum net electrical energy output the unit would have produced if operated at the maximum dependable capacity for the entire period, expressed as a percent."

Maximum dependable capacity (MDC) is "the gross electrical output as measured at the output terminals of the turbine-generator during the most restrictive seasonal conditions, less the normal service loads."

As a result of the manner in which unit capacity factor is defined, recorded values may vary on a monthly basis (and even exceed 100%) solely due to environmental considerations. NRC also reports a capacity factor based on the design rating of the unit turbine.

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