AVAILABILITY OF FOSSIL-FIRED STEAM POWER PLANTS

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ABSTRACT

Fossil-fired power plants of 600 MW or larger constitute a major proportion of the baseload capacity in the country but have the poorest availability record of any size category. Two primary aims of the EPRI Fossil Plant Performance and Reliability Program are short-term improvement of existing plant reliability, and initiation of work to eliminate current deficiencies in future plants.

To define the problems and develop a strategy for improving the availability of over-600 MW fossil-fired plants, the statistics compiled by the EEI have been analyzed, and the resulting conclusions have been supplemented by meeting with utilities which operate power plants in that category.

The annual availability reports published by the Edison Electric Institute are based on statistics which aggregate the outage hours from specific failure causes or problem areas. By assigning costs to outages ($4000/hour for forced outages, $1000/hour for scheduled ones), the relative importance of various problem areas has been determined. Boiler tube failures (water tubes, superheater tubes), turbine blade failures, condenser problems, and boiler-feed pump and drive problems have the highest cost impact among the 24 problem areas identified as either "high cost" (over $15 million annually) or "moderately high cost" ($5 to $15 million annually) calculated according to the approach previously described.

To supplement the EEI data, six regional meetings were held by EPRI with utility representatives directly concerned with operating fossil plants of over 600 MW. The informal discussions generally confirmed the relative importance of the problem areas, and provided valuable information on the causes and relationships between problems which statistics alone could not provide. The results of these meetings are recommendations regarding the problems which should be addressed and the role which EPRI should play in defining the work and sponsoring both research and development and improved information flow to industry, including the results of this and related research efforts.

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Thanks are due to all those utility executives who contributed their time, especially Robert H. Swoyer who chaired the meetings, and the following who took part in most of them: M.C. Brickell, J.B. Burkhardt, L.K. Mundth, A.O. Spencer, G.C. Weidersum, and A.H. Gibson.

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EXECUTIVE SUMMARY

This report summarizes recent experience affecting the reliability of fossil fired steam generating units of 600 MW capacity or more.

Statistics published by the Edison Electric Institute show the availability of this class of plant to be about 73% compared with around 80% for smaller plant. Since EPRI is currently building up a research program aimed at improving fossil plant performance and reliability it is clearly desirable to identify the principal problem areas, with emphasis on the newer large units. To a lesser degree, similar problems also occur on the smaller units.

The first stage in the process was selection of grouping of the data published by EEI in their Summary Report. Eleven problem areas, each with total annual direct costs to the industry of at least $15 million, were identified, and a further thirteen with costs between $5 million and $15 million. The total annual cost of plant unavailability is at least $750 million for units over 600 MW alone.

The EEI data has been supported and amplified by a series of informal meetings between EPRI and utility staff. These meetings were valuable in obtaining direct utility inputs which were more up to date, by some two years, than the published data and in producing a deeper insight into the nature of reliability problems.

The results of these meetings are summarized and the findings discussed against brief technical descriptions of the relevant plant items. The nature of the major problems in the boiler, turbine generator, and auxiliary components are summarized, with recommendations for a systematic approach to effect improvements.

Section 1

INTRODUCTION

FOSSIL PLANT AVAILABILITY DATA

Two primary aims of the EPRI Fossil Plant Performance and Reliability Program are short term improvement of existing plant availability, and initiation of work to ensure that new plants will not suffer the same deficiencies as those now operating. As with any research and development program, this requires a clear definition of the problems to be addressed. From this basis, a strategy may be developed with priorities fixed by the relative importance of the problems, the probabilities of resolving or avoiding each one, and the costs involved in each case.

This report describes a preliminary analysis of the availability of large fossil-fired power plants with the broad objectives of defining (1) the plant areas which principally contribute to nonavailability and, (2) as far as possible, the reasons for nonavailability.

Detailed statistics on fossil plant outages are not collected nationally. The records kept by the Edison Electric Institute (EEI) cover only the investor-owned sector, which is the largest part of the utility industry. There is no equivalent collection of reliability data for the other sectors. This situation contrasts with statistics on nuclear power plant availability. Nuclear plants are subject to a variety of strict regulations which require the maintenance of fairly detailed failure and outage records. Their statistics are collected by the American National Standards Institute, Nuclear Regulatory Commission, and Federal Energy Administration as well as by the EEI.

Data on power plant availability collected by the EEI are intended to provide mainly a base for utility managements who are concerned with system planning, procurement of equipment and efficient utilization of generating resources. The information and the EEI presentation of it serve very well for these purposes. Contributing utilities can extract a great deal of information which helps with the selection of reliable equipment, and indicates the performance that can be expected from it.

It was never the intention of the EEI to provide information on root causes of failure, which would require a much greater effort. However, informal information on plant failures is provided through meetings of the Prime Mover's Committee which serve as closed confidential forums for member utilities.

EPRI has attempted to obtain a more intimate picture of fossil plant problems by meeting with several major utilities, also on an informal and confidential basis. The information in this report derives entirely from the published EEI data and from these meetings. Although the report contains only nonspecific information in keeping with concerns for confidentiality, very little has been lost in the process of assembling the overall findings.

DATA PUBLISHED BY THE EDISON ELECTRIC INSTITUTE

The Edison Electric Institute annually publishes two summaries of outage statistics for fossil-fired power plants. These give ten year averages of two types of data pertaining to plant availability:

- Outage data for generating units, boilers, and turbine generators, expressed in clearly defined terms which are in common use by the industry (Full Forced Outage, Equivalent Forced Partial Outage, Maintenance Outage, etc.).

- An analysis of outage causes which follows a standard EEI coding.

Two widely-quoted sets of characteristics are derived from the EEI data. The average availability for units of different sizes is shown in Table 1-1. The total outage hours attributed to various causes are shown in Table 1-2.

In fact, the EEI statistics warrant much closer inspection. Even the published information can provide a useful guide to problem priorities. The total of data collected is very comprehensive, but is available only on a restricted basis, and has not been used in this report. Tables 1-3, 1-4, and 1-5 show selected outage-cause data assembled in groups corresponding to the boiler-related, turbine-generator-related, and auxiliary systems respectively. These tables omit items which were found by inspection to be of minor importance

Table 1-1

AVAILABILITY AND FORCED OUTAGE RATE BY
SIZE GROUPS, 10 YR AVERAGE, FOSSIL FIRED POWER PLANT

UNIT SIZE	AVERAGE AVAILABILITY		AVERAGE FORCED OUTAGE RATE	
MW	1964-73	1965-74	1964-73	1965-74
60-89	91.7		2.0	
90-129	88.3		3.5	
130-199	89.0		3.3	
200-389	85.9		4.9	
390-599	79.6	78.9	8.9	9.5
600 and larger	72.9	73.3	16.5	15.8

Source: Edison Electric Institute. Report on Equipment Availability for the Ten-Year Periods 1964-1973 and 1965-1974.

Table 1-2

OUTAGE HOURS ATTRIBUTED TO CAUSES
600 MW AND LARGER UNITS - 10 YR AVERAGE 1964-73

CAUSE	FORCED OUTAGE HOURS		MAINTENANCE OUTAGE HOURS		PLANNED OUTAGE HOURS	
	390-599MW	600MW+	390-599MW	600MW+	390-599MW	600MW+
Boiler	372	572	305	328	529	540
Turbine	159	213	170	273	591	510
Condenser	9	17	66	136	349	166
Generator	57	267	112	197	403	349
Other	61	82	94	213	272	157
Unit	654	1133	327	364	732	691

Source: Edison Electric Institute. Equipment Availability Fossil Component Cause Code Summary Report 1973.

Table 1-3

ANALYSIS OF BOILER RELATED OUTAGES, FOSSIL FIRED UNITS OVER 600 MW

	OUTAGE CAUSE OR PROBLEM AREA																		
	GENERAL	WATER TUBES	SUPERHEATER & REHEATER	ECONOMIZER	AIR HEATER	FANS	VALVES	ASH DISPOSAL	PULVERIZERS	FUEL HANDLING	CASINGS BREECHING	PRECIPITATOR	BURNERS	EXPLOSIONS	CONTROLS	FOULING, CLEANING	COAL	TOTAL LISTED	OUTAGE RATE
EEI FAILURE CAUSE CODE	100	101,102	103,104	106	107,108	109,110 111	115,116 117	119	121,145	123	126	130	132	133	134	124,136 137,138	142,143		
FFO (hr)	137	121	96	14	10	13	16	12	4.4	15	7.6	4.8	5.5	23	24	23	3.2	530	6%
INCIDENCE	1.8	1.5	.84	.20	.09	.31	.51	.16	.20	.30	.10	.09	.19	.03	1.8	.28	.11	8.7	
HRS/INC.	75	81	115	68	111	42	31	79	22	48	73	54	29	769	13	82	29		
EFPO (hr)	9.9	4.9	3.5	13	16	30	3.1	7.8	40	6.9	.63	2.6	1.3	.34	2.2	20	18	180	2%
INCIDENCE	.99	.31	.33	.06	1.1	2.9	.56	2.7	13	6.3	.24	.32	.25	0	.85	11	7.8	49	
HRS/INC.	10	16	11	227	15	10	5.5	2.9	3.0	1.1	2.7	8.2	5.4	69	2.6	1.8	2.4		
SCHED.OUT (hr)	653	14	6	3	29	16	10	2	13	0	4.8	18	1.9	0	11	15	3	800	9%
% TOTAL	82	10	5.8	10	53	27	35	9.1	23	0	37	72	22	0	30	26	12	53	
TO (hr)	800	140	106	30	55	59	29	22	57	22	13	25	8.7	23	37	58	24	1510	17%
INCIDENCE	4.3	2.0	1.2	.27	1.4	3.1	1.3	3.1	.6	6.8	.38	.68	.50	.03	2.8	14	8.4	60	
HRS/INC.	187	70	88	110	39	16	23	7.2	3.6	3.2	34	38	17	669	13	4.1	2.9		
ANNUAL REL COST* ($mm)	124	52	40	11	13	19	7.7	8.1	19	8.8	3.8	4.7	2.9	9.3	12	19	8.8	364	
REL PRIOR.		H	H	M	M	H	M	M	H	M				M	M	H	M		

KEY

FFO - Full Forced Outage
EFPO - Equivalent Forced Partial Outage
TO - Total Outage
Incidence - Average number of events/unit year

H - High Impact ($15 million pa)
M - Moderately High Impact ($5-$15 million pa)

* Relative Cost-Base is 100 units at means outage cost
$4000 per hour forced outage per unit
$1000 per hour scheduled outage per unit

Data Source: Edison Electric Institute. Equipment Availability, Fossil Component Cause Code Summary Report 1973.

Table 1-4

ANALYSIS OF TURBINE GENERATOR RELATED OUTAGES, FOSSIL FIRED UNITS OVER 600 MW

	OUTAGE CAUSE OR PROBLEM AREA																			
	TURBINE										GENERATOR									
	GENERAL	CONTROL, GOV.	VALVES	1st, ST., NOZZLE	SHAFT, WHEELS	BLADES	VIBRATION	BEARINGS, LUBRICATION	TOTAL LISTED	OUTAGE RATE	GENERAL	BEARINGS, LUBRICATION	H_2 COOLING	LIQ. COOLING	SEALS	STATOR WINDING	STATOR IRON	ROTOR WINDING	TOTAL LISTED	OUTAGE RATE
EEI FAILURE CAUSE COST	600	621,632	622	624,625	627,628	624	630	631			700	701	703	704	705	706	707	708		
FFO (hr)	2[illegible]	8.6	12	--	8.3	43	46	48	193	2%	90	9.2	9.9	2.7	80	15	24	.79	232	3%
INCIDENCE	.22	.54	.38	--	.04	.06	.71	.16	2.1		.13	.02	.11	.03	.10	.01	.02	.01	.43	
HRS/INC.	126	16	31	--	208	725	64	305	--		701	375	87	79	814	1507	974	80		
EFPO (hr)	.30	2.4	6.9	--	00	25	11	1.8	47	.5%	2.8	00	.90	.06	1.3	--	.02	3.1	8.2	
INCIDENCE	.04	.37	.54	--	00	.42	.99	.12	2.5		.12	.01	.28	.04	.12	--	.01	.13	.71	
HRS/INC.	6.8	7.5	13	--	1.0	58	11	15	--		24	.33	3.2	1.5	11	--	1.6	25		
SCHED OUT (hr)	623	18	11	--	4.7	26	20	20	720	8%	510	2.8	4.2	0.1	13	00	1	2.0	533	6%
% TOTAL	96	62	37	--	36	54	40	31	75		84	23	28	3.5	14	00	4	34	69	
TO (hr)	650	29	30	.03	13	94	77	70	960	10%	603	12	15	2.9	94	15	25	5.9	773	9%
INCIDENCE	1.9	1.1	1.2	00	.09	.56	2.4	.38	7.6		1.1	.04	.47	.11	.23	.01	.07	.15	2.2	
HRS/INC.	348	26	25	6	140	170	32	184	--		544	302	32	25	407	1507	359	40		
ANNUAL REL COST* ($mm)	98	6.2	8.7	--	3.8	32	26	21	171		88	4.0	4.6	1.1	34	6.0	9.7	1.6	149	
REL PRIOR.		M	M			H	H	H							H	M	M			

KEY

FFO - Full Forced Outage
EFPO - Equivalent Forced Partial Outage
TO - Total Outage
Incidence - Average Number of Events/unit year

H - High Impact ($15 million pa)

M - Moderately High Impact ($5-$15 million pa)

* Relative Cost - Base is 100 units at mean outage cost
$4000 per hour forced outage per unit
$1000 per hour scheduled outage per unit

Data Source: Edison Electric Institute. Equipment Availability, Fossil Component Cause Code Summary Report 1964-1973

Table 1-5

ANALYSIS OF AUXILIARY COMPONENT OUTAGES, FOSSIL FIRED UNITS OVER 600 MW

	OUTAGE CAUSE OR PROBLEM AREA																				
	Condensers									Feedwater Heaters				Boiler Feed Pump					Fuel Handling	
	GENERAL	CLEANING	TUBE FAILURE	CW PUMP	COND PUMP	EXPANSION JOINT	MISCELLANEOUS	TOTAL LISTED	OUTAGE RATE	LEAKS	DIRTY	TOTAL LISTED	OUTAGE RATE	GENERAL	DRIVES	BF PUMP	TOTAL LISTED	OUTAGE RATE%	COAL CONVEYING	OUTAGE RATE
EEI FAILURE CAUSE CODE	800	801	802	803	804	809	899			901	902			905	918,919 920,921	922			906	
FFO (hr)	.92	.38	2.1	2.7	1.4	1.7	6.8	16	.2%	6.1	0	6.1	.1%	25	3.2	.95	29	.3	.77	--
INCIDENCE	.05	.02	.04	.05	.06	.01	.12	.35		.11	0	.11		.74	.19	.07	1.0		.02	
HRS/INC.	17	19	47	49	22	117	58			54	0			34	17	13			31	
EFPO (hr)	.45	1.0	4.9	3.8	2.9	.20	2.9	16	.2%	9.6	.22	9.8	.1%	45	6.2	3.2	54	.6	3.7	--
INCIDENCE	.08	.42	.92	.20	.56	.02	.48	2.7		.81	.06	.87		3.6	1.1	.53	5.2		.93	
HRS/INC.	5.3	2.5	5.3	19	5.2	10	6.0			12	3.7			13	5.6	6.1			4.0	
SCHED OUT (hr)	285	18	1.5	.2	1.4	1.9	0.3	308	3.5%	4.3	0	4.1	0	62	2.6	2.6	67	.7	1.7	
% TOTAL	100	95	18	3	25	50	3	91		22	0	20		47	22	38	44		27	
TO (hr)	286	19	8.5	6.7	5.7	3.8	10	340	3.8%	20	.22	20	.2%	132	12	6.8	151	1.7	6.2	.1%
INCIDENCE	.87	4.1	1.0	.33	.83	.05	.65	9.5		1.1	.06	1.17		5.6	1.4	.71	7.7		1.1	
HRS/INC	328	4.7	8.3	20	6.9	71	16			18	3.7			23	8.6	9.5			5.8	
ANNUAL REL COST* ($mm)								44				6.8					39		2.4	
REL PRIOR.								H				M					H			

KEY

FFO - Full Forced Outage
EFPO - Equivalent Forced Partial Outage
TO - Total Outage
Incidence - Average Number of Events/Unit Year

H - High Impact ($15 million pa)

M - Moderately High Impact ($5-$15 million pa)

* Relative Cost - Base is 100 units at mean outage cost
$4000 per hour forced outage per unit
$1000 per hour scheduled outage per unit

Data Source: Edison Electric Institute. Equipment Availability, Fossil Component Cause Code Summary Report 1964-1973 relative to the unit sizes considered. They also group certain cause classifications (e.g., superheater and reheater tubes) which have a close technical relationship.

In each of Tables 1-3, 1-4, and 1-5, the outage data are in three sections: Full forced outages (FFO); equivalent forced partial outage (EFPO); and total outage (TO). Scheduled outage time has been taken as the difference between total outage time and the sum of full and partial forced outage times. For each section, the average outage hours per unit year, the average incidence of failure and the mean outage time are given by outage cause or problem area.

These tables provide a basis for an initial rating of the impact of various problems. They indicate the frequency of various incidents that cause full or partial forced outages, and the extent that they extend the need for scheduled outages. Within the limitations imposed by the data, the tables permit an objective ranking of problem areas. To show the relative impacts of the main problem areas as directly as possible, approximate annual costs have been calculated for each one.

The financial impact of a plant outage has two main components: direct costs (labor and materials), and the differential cost of replacement power (purchased or provided by operating less economical plants). For fossil-fired power plants above 600 MW, capacity replacement power costs of $100,000 to $300,000 per day were quoted to EPRI in the course of the six regional meetings which are summarized later in this report. In fact, the cost depends on factors such as the outage time (month, day, or hour) in relation to the time of peak demand, the size of the unit in relation to the size of the utility system, and the source of replacement power. Scheduled outages are distinguished from forced outages because it is usual to choose a time when the replacement power costs are minimal. However, for a lengthy outage it is clearly possible to avoid only seasonal peaks of power demand. When the unit is a major part of a utility's capacity, the replacement power costs are likely to be considerable at any time.

In this report, average forced outage costs have been taken as $4,000 per hour, which is approximately $100,000 per day. Scheduled outage costs have been estimated at $1,000 per hour. These figures are certainly minimal. In particular, scheduled outages more than about 500 hours duration inevitably involve significant replacement power costs. This should be borne in mind especially when considering the impact of turbine generator faults, in terms of both relative economics and absolute costs.

To calculate approximate annual costs the 1964-73 EEI outage hours representing a total of 203 unit-years of experience, have been scaled down to the equivalent of 100 unit-years. This approximation assumes that the 1964-73 data will continue to be representative of the industry, at least for the near term. The results are believed to give a reasonable approximation to near-term industry costs for each problem area, as there are now more than 90 operating units in the over-600 MW category.

The estimated annual cost for each problem area has been used to assign some of them to cost categories on the following basis:

- High Cost Impact - Annual cost over $15 million

- Moderately High Cost Impact - Annual cost from $5 million to $15 million

On this basis, the boiler subsystem has five high cost impact problem areas, and the turbine-generator system has four problem areas in that cost category (three in the turbine, one the generator). Among the auxiliaries, problems of condensers and of boiler-feed pumps also have economic impacts in that range.

In the moderately high cost category there are eight problem areas of boilers, four of turbogenerators, and one among the plant auxiliaries (feedwater heaters). The problem areas and estimated annual costs are as summarized in Table 1-6. While these figures are no more than ballpark estimates, they do have a common cost basis and therefore provide reasonably valid comparisons.

The apparent severity of coal-related problems of all kinds tends to be reduced in the averaging process, since the 203 unit-years included in the EEI data covers oil, gas, and coal-fired units. The current trend toward a larger proportion of coal-fired units will in itself increase the overall impact of problems which are specific to coal firing.

Table 1-6

SUMMARY OF PRIORITY PROBLEM AREAS
FOSSIL FIRED UNITS OVER 600 MW

PLANT SUBSYSTEM	TOTAL ANNUAL OUTAGE COST OVER $15 MILLION		TOTAL ANNUAL OUTAGE COST, $5 MILLION-$15 MILLION	
	PROBLEM AREA	ESTIMATED ANNUAL COST ($ MILLION)	PROBLEM AREA	ESTIMATED ANNUAL COST ($ MILLION)
BOILER	Water tube failures	52	Air heater	13
	Superheater tube failure	40	Controls	12
	Fans	19	Economizer	11
	Pulverizers	19	Explosions (and implosions)	9.3
	Fouling and cleaning	19	Coal	8.8
			Fuel handling	8.8
			Ash disposal	8.1
			Valves	7.7
TURBINE GENERATOR	Turbine blade failures	32	Turbine valves	8.7
	Vibrations	26	Turbine controls & governors	6.2
	Bearings	21	Generator stator iron	9.7
	Generator seals	34	Stator windings	6.0
AUXILIARY PLANT	Condensers	44	Feedwater heaters	6.8+
	Boiler pumps and drives	39		

Problem priorities also depend on other considerations, including the impact of individual incidents, and secondary effects. Also, it must be recognized that the EEI reporting system allows ambiguity and is loosely interpreted in many cases. For instance, the designation of "coal" as an outage cause often can be interchanged either with "pulverizers" or "fouling and cleaning."

Similarly, many turbine outages ascribed to "vibration" (which is a common sympton) may be due to either blade failures or bearing failures.

Turbine generator problems characteristically cause long outage times, but are relatively infrequent. The statistical base therefore is too small for averages to be significant. The data tend to fall into two sets of small numbers. One represents very long outages and the other, very short ones. Turbine generator outages which approximate the average duration are rare.

About half of all boiler outage hours are scheduled, and 80% of the scheduled outages are attributed to the "boiler general" category in the EEI cause code. This probably indicates that many outages result from the cumulative effects of several defects. The data also show that the average "general scheduled" outage is of much longer duration than the individual forced outages. The net effect of including "general outages" in the data base is to encourage loose reporting so that much of the preventive and corrective work done on boiler systems cannot be identified from the statistics. If this work were assigned to the appropriate cause codes, it could alter significantly the picture of boiler-related problems. This is particularly true of faults which cause partial outages more often than full outages.

Scheduled outage time for turbines and generators is around 70% of the total. Most of the scheduled outage time is categorized as "general." This probably implies that much of the necessary repair and maintenance work on a turbine is accomplished during forced-down time attributed to the boiler or generator. Conversely, much of generator work can be performed during forced down time caused by the turbine or boiler.

Gall & Musick* have observed that total unit outage time can be expressed as the sum of the total boiler outage time, the sum of the forced outage times for other plant elements, and a small constant. For the abridged data on units over-600 MW, which is considered here, their approach suggests we should expect a unit outage rate of 17% + 7% + 1.5% = 25.5%. Using the complete data, as reported by EEI, gives a slightly higher total, 27.5%. The reported unavailability of units in this case was 27.1%. This close agreement, and the general validity claimed for this relationship, supports the conclusion that operators generally find it less disturbing to production to tolerate noncritical "other plant" problems until forced off by a failure in the boiler system.

*D. G. Gall and V. S. Musick, "Experience with Data Collection on Operation of G. E. Turbine Generator Sets," IEEE 3rd Annual Reliability Eng. Conf. 1976, Cat. 76 CH 1171-8 MON.

Section 2

REGIONAL MEETINGS WITH UTILITIES

To supplement data from the EEI records, and to obtain a more up-to-date picture, EPRI held six meetings with utility representatives in different regions of the country. Representatives were invited to each meeting from utilities which had operating experience with power generating units of 600 MW or more. The 32 utilities which participated are listed in the Appendix. The individuals who attended were engineers and managers concerned directly with design, operation or maintenance of the plants.

Participants were selected on the basis of experience with units in the 600 MW or larger class to focus the discussions on modern plants which represent current new plant ordering trends. This class of large units constitutes a major proportion of the base-loaded capacity in the country. Moreover, there is no doubt that these large units collectively have the worst overall availability record of any size category. The fact that replacement power costs for any unavailable unit are in direct proportion to its scheduled output emphasizes the significance of this situation.

An important advantage of this selectivity was that it limited the meetings to a reasonable size. This permitted fairly detailed discussions at each location.

Some consideration was given to the objection that this approach might overlook the problems of smaller generating units. The discussions frequently included the performance of smaller units. So far as could be ascertained, differences in reliability between units of various sizes are essentially matters of degree rather than differences of character. The advances required to resolve the problems of the largest units will thus contribute to the resolution of many problems of smaller units.

The meetings were informal, with no set form for presentations. This approach minimized preparation by the participating utilities and also encouraged a free exchange of information. Each organization was free to give as much or as little information as it wished. Notes on the discussions were circulated only within EPRI and among the persons who attended the meetings.

The very informal procedure was a disadvantage to summarizing the results. The presentations differed greatly in terms of the amount of detail, the form in which data were set out, and the definitions used to describe different classes of outage. For these reasons, the meetings produced little quantitative information beyond that available from the EEI data. Indeed, despite efforts to the contrary, many presentations contained more opinions than facts. The value of these opinions must not be underestimated however, since practiced engineers develop a strong sense of the way that problems are developing and it is important to include all viewpoints, including personal ones, that may shed light on reliability problems. Nonetheless, the circumstances require that the data be interpreted with care. The information collected and its presentation leave room for errors of judgment by the reviewer.

Better data might have been obtained if some degree of uniformity had been imposed either on the presentations, or on the subsequent question and answer sessions, but this would have increased the risk of some utilities withdrawing from the discussions. This weakness in the formal approach has been mitigated by the inclusion of the EEI data in the previous section.

ORGANIZATION OF FINDINGS

This part of the review summarizes the findings from the regional meetings in terms of major plant groupings. There is also a discussion of so-called "shakedown problems" which were frequently mentioned, and which perhaps are more readily accepted than they should be.

Each major plant grouping is subdivided according to components and conditions which were found to be most representative of the experience in the industry. These subdivisions do not conform exactly with the categories in the EEI data which are summarized in the Appendix. However, most of them can be recognized readily from Tables 1-3, 1-4 and 1-5. The categories used are shown in Table 2-1.

Table 2-1

CATEGORIES OF FINDINGS FROM EPRI REGIONAL MEETINGS
PROBLEMS OF FOSSIL FIRED UNITS OVER 600 MW

BOILERS	TURBINE-GENERATOR	AUXILIARY SYSTEMS	SHAKEDOWN
Tube Failures	Blading	Draft Systems	Design
Slagging and Fouling	Bearings and Lubrication	Feed Systems	Testing
Furnace Implosions and Explosions	Vibrations	Valves	Supervision
Structural Failures	Water Induction	Condenser Systems	
Exfoliation	Turbine Controls	Coal and Ash Handling	
Boiler Controls	Structural Features		
Other Boiler Components	Generator Stator		
	Generator Rotor		

BOILERS

Tube Failures

Many participants stated that boiler tube failures are the most serious plant problem, a finding supported by the EEI statistics for causes of boiler forced outage (Table 1-3). Forced outage rates from this cause on the order of 15% were reported by some utilities, and outage rates in the range of 5% to 10% seem commonplace. The EEI data (Table 1-3) indicates a 2.8% average outage rate.

More than 9C% of boiler tube failures cause forced outages. This outcome is almost inevitable (although the shutdown can be deferred for a limited time) unless the failure is detected during a leak test while the boiler is out of service. In contrast, many other faults can be tolerated, perhaps with a load reduction, until a convenient outage occurs for other reasons. Such "tolerable" problems can be corrected at will and are absorbed during scheduled outages.

A tube failure typically results in an outage of 3-6 day's duration because of the need to drain and cool the boiler for access. Superheater repairs ordinarily require the most time because of the need for extensive scaffolding in the repair area. Tube failures occur for a variety of reasons, some of which can be traced to root causes in other parts of a plant. Inadequacies of design, fabrication, or operation can lead to failure of the most severely loaded part of the boiler circuit.

Because of significant differences in service conditions, it is convenient to group tube failures into three categories:

- Waterwall
- Superheater and reheater
- Economizer

Waterwall tubes are normally carbon or low alloy (1% Cr.) steels. While subjected to moderate temperatures, they are exposed to very high heat fluxes, especially in oil-fired plants. Occasionally they can experience severe internal corrosion conditions wherever very high heat fluxes, inadequate water circulation, or upsets of water treatment occur. Severe external corrosion can be caused by certain fuels or combustion conditions.

Compared with waterwalls, superheaters and reheaters operate at higher temperature but lower heat fluxes. The limiting design criterion is usually creep strength. Operating lifetime therefore depends critically on operating temperature, and any weakening by corrosion or erosion accelerates failure.

Economizer tubes are more subject to erosion damage than any other, because of the high gas velocities and close tube arrays used to achieve the most cost-effective designs.

Waterwalls. Twelve of the thirty-two utilities reported serious problems with waterwall tube failures. Three of the twelve were cyclone-fired coal burning installations. Another cyclone installation, which seemed to be free of major trouble, was operating at less than 90% of design rating.

Two cases of severe waterwall failure were in oil-fired units. In one case, the boiler was designed for coal firing and is now operating on oil. Oil firing typically produces short, concentrated, and very hot flames compared with coal firing, requiring corresponding increases of water circulation rates for safe tube operation. In the case cited, tubes showed signs of external cracking in the burner zone corresponding to the highest heat fluxes. It is not clear whether there were corrosion mechanisms involved but they could be contributory in the overheated situation suggested by the tube condition.

The second oil-fired unit, although relatively new, had already suffered severe internal scaling. This was a cycling duty unit, and EPRI sponsored work (RP644) has shown that cyclic conditions aggravate scaling processes. However, damage sufficient to cause such rapid tube failures suggests that there were other exceptional factors involved.

Waterwall failures in coal-fired units frequently were ascribed to erosion, corrosion, or external forces. Erosion in the furnace area usually is associated with soot blowing. Ash particles, entrained by the soot blowing jet, impinge on the tubes at high velocity. External tube corrosion problems have been known throughout the history of coal firing and have been extensively researched. There is no single corrosive agent to which corrosion by fuel impurities can be attributed, but sulfur compounds are certainly involved. Local reducing conditions at the furnace wall exacerbate the situation. These conditions stabilize sulfidizing agents and permit reactions which reduce the oxide coatings which normally protect the surface. In several cases, tube damage was reported to be more severe in the burner zone, and some improvement had been gained by bleeding air into the furnace at the wall.

In modern boiler wall construction strips of metal, usually about 1/2 inch wide and 1/4 inch thick, are frequently welded continuously between adjacent tubes to form a "membrane wall." The rigid connection between tubes, plus the need to transmit larger restraining forces to the boiler structural supports, has increased the number of mechanical failures in which tubes tear at the tube restraint lug.

Other reasons cited for waterwall tube failures were the restriction of tubes by debris or foreign bodies, weld failures, fatigue, and damage by slag falls. There was no obvious correlation among these with either boiler type or vendor.

Superheaters and Reheaters. Nearly all the utilities represented showed that superheater and reheater tube failures are a general problem of major importance. Except where there were tube restrictions, or where erosion by dust laden gas (more usually by soot blowers) was involved, the causes often were not clearly identified. Temperature excursions or continuous operation at abnormal temperatures may be inferred in some cases. The life/temperature relationship of materials in creep is such that even intermittent overheating cannot be tolerated. There were several cases where steam temperature control was shown to be inadequate. In others, the gas flow and/or steam flow distributions were not good.

As with waterwall tubes, low cycle fatigue or other mechanical damage has been experienced, expecially where expansion movement is restrained in the region of header connections.

Economizers. The economizer was reported as a major problem area in a few cases. Most utilities, especially coal users, experienced some failures. Tight tube pitching makes access to economizers difficult, which can lengthen repair times relative to other tube-failure repair. These impressions are supported by the EEI data (Table 1-3). The common cause of economizer failures is erosion, often by ash passing around the bends at the ends of the tube banks. The use of baffles to deflect the flow can simply deflect the problem. In the author's experience, either labyrinth techniques (i.e., use of a series of baffles), or "building in" the tube ends has proved effective.

Slagging and Fouling

Although slagging and fouling are often stated to be a serious problem, its severity does not approach that of tube failures according to both the EEI statistics and the meetings reported here. However, about half the utilities consider it to have a very significant effect on availability, because it usually necessitates load restriction or reduction.

Regular load reductions are often imposed to introduce temperature cycles which loosen deposits. These also can have an adverse effect by causing thermal stress cycles in the plant as a whole. Occasional incidents of superheater fouling, throat bridging, or heavy slag falls required boiler shutdown to restore normal operation, but these were exceptions.

Load reduction, or boiler derating, on the order of 10% results in more serious financial penalties. Often this does not appear in outage returns as it becomes accepted as normal practice. Slagging and fouling are probably underestimated as problems, since utilities learn to live with them.

From the evidence, it may be argued that slagging and fouling are frequently symptoms of either incorrect furnace design or equipment inadequacies. The usual reason given for slagging and fouling problems was either deterioration or change of fuel supplies. Frequently, both the amount and nature of ash in the coals fired were different from those assumed at the time of ordering and designing the boiler. To allow for possible variations of fuel quality requires, in general, provision of extra pulverizer capacity, furnaces of generous proportions and wide tube spacing. Many of the units discussed at these meetings were built during a period when the boiler market was fiercely competitive. Frequently, commercial pressures overrode engineering judgment, and the necessary margins were not provided.

It is not clear to what extent slagging and fouling is aggravated by firing coarse coal which delays completion of combustion and leads to coal burning on the slag deposit. In several cases, pulverizer capacity was said to be insufficient to handle the increased coal tonnage required by reduced heating values. Together with the increased wear and maintenance due to high ash levels, this would certainly be expected to result in a coarser pulverized product and inefficient combustion. One utility gave this as the reason for increased slagging and tube corrosion, and it probably applies more generally.

The behavior of coal ash depends strongly on both the temperature and atmosphere to which it is exposed. Melting point is usually depressed by a reducing atmosphere. Flame temperatures increase as excess air is reduced to approach stoichiometric conditions. Air and fuel distribution are vitally important factors in deciding slagging and fouling behavior. However, it was not apparent from the discussions whether any systematic steps had been taken to study or improve these conditions.

Furnace Implosions and Explosions

Occasional furnace explosions always have been a hazard, with all kinds of firing, but implosions are a relatively modern phenomenon. When a trip causes a sudden loss of flame, rapid furnace cooling leads to reduced pressure of the enclosed gases. The effect can be accentuated if a fuel trip initiates a shutdown of the FD fans F.D. damper closure, or I.D. damper opening. Although the incidence of implosions is low, the potential for major damage and possibility of injury to personnel make them a real cause for concern. The EEI data confirm this conclusion.

Furnace structural design techniques must be based on systems of external girths and buckstays. Consequently, support against implosion is more difficult to achieve than support against explosion. Membrane wall construction effectively prevents the inleakage of air that could reduce the furnace pressure depression. Although it does not seem to have been considered by designers, this could be a prime reason for the increased incidence of major damage from furnace wall collapse following implosions.

Three utilities reported implosions of varying severity, and there was one reported explosion. One utility had experienced three successive implosions. In other cases, severe negative excursions of furnace pressure had been noted, leading to measures to strengthen the furnaces.

The probability of an implosion can be reduced greatly by appropriate design of the draft control trip sequence. Some utilities reported modifications which reduced the pressure excursion by half. The essential feature was delay in closure of the F.D. system. However, particularly in an oil-fired unit, collapse of the flame following a main fuel trip can be too rapid for fan or damper response to be fully effective. In such cases, improved structural standards appear desirable. Accurate predictions of transient furnace pressures and analysis of the structural response both present formidable problems.

Structural Failures

Eleven utilities reported boiler structural failures, some having had more than one major problem. Some of these cases have been referenced previously in the discussions of tube restraint tearing and implosions.

Five utilities also reported failures of ducts, for which the average outage times were about 100 hours. Three utilities which reported specifically in this area each listed several occurrences. This suggests that duct failures may be more frequent than is indicated by the survey. Dust accumulations and acoustic resonance are factors contributing to duct failure. Structural weakening by corrosion also plays a part. The acoustic and flow characteristics of ducts are amenable to analytic and flow modelling approaches which do not appear to be fully utilized in design.

Structural failures in the main part of the boiler can cause major outages. Dust accumulation in the penthouse region of pressurized furnaces can add appreciable dead loads and thus lead to failure. One utility removed 1700 tons of fly ash from this region in a 600 MW boiler. The resultant damage required replacement of the penthouse floor, hangers and springs. In another single outage, unspecified structural damage to the drum enclosure was responsible for 1041 hours lost operation.

Structural failures, apart from ducting and breeching failures, cannot be identified from the EEI failure cause codes.

Exfoliation

Exfoliation of oxide scale from the inner surfaces of steam tubes and pipes is primarily a boiler problem which often is reported in terms of resulting turbine damage. Ten utilities reported exfoliation damage to large turbines, of which seven cases were with supercritical units. There is probably no significance in the latter fact, as a majority of the units over 600 MW are supercritical. The reported cases of severe erosion of HP blading and nozzles in subcritical turbines is roughly proportional to their number.

The morphology of oxide films formed on the inside of boiler tubes varies widely from impermeable to very porous conditions. Thin impermeable magnetite layers are stable and protective. More permeable layers permit diffusion of oxygen and iron, and can concentrate water impurities which result in severe pitting corrosion. The nature of the oxide formed during initial commissioning depends on the boiler material, preoperational cleaning, water treatment, and temperature and pressure of initial operation. If the oxide formed initially is not protective, it cannot be made protective. Subsequent scale growth is apt to be detached during thermal cycles. The chemistry of this initial phase of operation is complex, but must be understood more completely if the exfoliation problem is to be overcome.

"All stainless" superheater or reheater construction is not necessarily the answer. Although a "stainless" steel may form less scale than carbon steel, its metal/scale junction may suffer more severe thermal stress which jeopardizes scale adhesion.

This problem is not detectable from the EEI data which shows the turbine first-stage area to be trouble free.

Boiler Controls

The principal boiler control loops regulate firing rate, air supply rate, furnace pressure (in balanced draft units) and water feed rate. The various loops are interrelated, but often are not integrated. Normally, the primary control signal is taken from the steam pressure. Instabilities may develop because the response capabilities of different parts of the system vary substantially. Also, several control subsystems -- notably burner controls and steam temperature controls -- are connected indirectly with the main control system and may interact with the main systems.

Twelve utilities reported unsatisfactory experiences with boiler controls. The resulting direct outage times generally were not great, but control excursions have impacts on boiler reliability. In particular, increased steam temperatures have significant effects on the life of superheater and reheater elements operating in the creep range. Also, main fuel trips, burner trips, and fan trips can lead to dangerous situations with risk of furnace implosion or explosion.

Some power station engineers learn to operate without effective controls. In one case, it was said that the "automatic combustion controls never worked." In other cases, multiple minor outages occurred, the control responses were unacceptably slow, or the unit "hunted."

The design and effectiveness of control systems may receive insufficient attention in many instances. It is perhaps unfortunate that boilers can be operated with indifferent controls. This may place an unnecessary load on the operator, endanger the plant and have a significant effect on system economics as a result of poor load-following capability.

The EEI data show controls as a moderately severe boiler outage cost item. For the above reasons they probably warrant a higher rating.

Other Boiler Components

Poor precipitator performance was cited in many cases as an outage cause. Apart from shutdowns to repair wires or insulators, poor performance, which seems to be common, could restrict unit capacity.

Tubular air heaters (of which there are relatively few) were reported to suffer from blockage and/or corrosion. Rotary regenerators with horizontal shafts have suffered mechanical damage from packing movement.

The horizontal arrangement of air heaters and the adoption of pressurized furnaces are two developments aimed primarily at cost reduction which have resulted in a sizable increase in maintenance problems. Many utilities now are converting pressurized units to balanced draft furnaces.

TURBINE GENERATOR

The turbines discussed at these meetings were all compound machines running at 3600 rpm. With minor variations, steam conditions were mostly 2400 psi or 3500 psi at 1000°F superheat, with single reheat (1000°F). There were a few double reheat units and some instances of higher steam temperatures. Contrary to expectations, the total duration of turbine outages was not much less than for boiler outages. Turbine generator outages often appeared as extended maintenance or planned outages rather than forced outages. The EEI data, Table 1-4, confirm the latter conclusion, showing only 25% of outage time as forced.

In particular, major turbine blade replacements frequently are performed during scheduled outages, although they result in extended down time. When the main rotating parts are involved, forced outages of turbines usually are long, often upwards of 1000 hours. If an in-service failure results in consequential damage, which is not uncommon, an outage of several thousand hours may follow. Blade, bearing, and rotor failures therefore have serious effects on availability. The EEI data also confirm this conclusion.

The relative cost figures derived in this report (Table 1-4) certainly underestimate the actual economic impact. Many long scheduled outages have been costed at $1000 per hour (following the ground rules adopted) although they would have affected productivity directly.

Only the mechanical features of generators were discussed at these meetings. However, electrical load disturbances and asynchronous resonance conditions in the transmission systems are translated to mechanical forces in the generator and transmitted to the turbine. The close coupling of the turbine and generator makes it impossible to divorce the two units mechanically to any significant extent. There is a need for interaction between electrical system engineers and mechanical engineers in this area. From an availability point of view, generator failures tend to cause lengthy outages (2000-3000 hours) and present an element of danger from electrical or hydrogen fires.

The EEI outage data show generator failures to be as serious a cause of outage as turbine failures. Together, the effect of these two is comparable with boiler failures. As in the case of turbine outages, the simple financial impact analysis used in this report leads to an underestimate of the aggregate economic impact.

Blading

Breakage of L.P. blades was the most general cause of turbine outage, causing both forced outages and extended planned outages for correction of design weaknesses. More than half the utilities represented had encountered blade breakages in L.P. turbines, usually in the last two rows. Blade failures in other locations were relatively rare, apart from those previously mentioned resulting from erosion by entrained oxide particles carried over from the boiler and connecting piping. In some cases, I.P. blading suffered similar damage resulting from exfoliation in the reheater.

Turbine blades are subject to regular impulses from steam at frequencies corresponding to the rate at which a rotating blade passes the successive steam passages between fixed blades (the blade passing frequency). This frequency is of the order of 5 KHz, which is above the natural frequencies of the long L.P. blades in both simple bending and more complex modes.

The successful design of such blades relies on the ability to operate in "windows" between the resonant frequencies to avoid failure from high-cycle fatigue. Since the blades are geometrically complex (i.e., they have twisted configurations and asymmetric sections), and are primarily designed as aerodynamic devices rather than structures, this capability is something of an art. Despite extensive preservice testing, not all blade designs fully meet the desired objective.

Where a problem is encountered, it is usually common to all machines which use the blade design in question and, of course, is specific to the vendor. There are several well known examples, of which some were evident from the meetings. These cases are clearly vendor related and were biased toward, but not unique to, one supplier. They are receiving considerable attention in the vendor's laboratories in an effort to arrive at rapid solutions. In general the correction of a fault condition is difficult and expensive, since it is necessary to open, reblade and rebalance the turbine.

Apart from correcting the design, there are other ways to minimize forced outages from L.P. blade failure. It is suspected that corrosion contributes to fatigue crack initiation and propogation. Hence, control of water/steam chemistry may delay or possibly avoid some cases of blade failure. Certainly poor chemical control will invite trouble. The problem apparently is as prevalent for supercritical units as it is for subcritical ones. Despite much higher feed water purity standards for supercritical units, the final steam purity is comparable to that in drum boilers because of high (virtually complete) carryover.

A second approach is based on early detection of blade cracking. At present cracks can be detected only during overhauls when the rotor is accessible. Careful checking at the early stages of major overhauls has permitted most reblading to be done during planned or extended maintenance outage periods. In such cases this has obviated the consequential damage that can follow a blade failure in service, but the resulting extension of the maintenance period in effect is forced outage.

Bearings and Lubrication

Failures of, or damage to turbine-generator bearings are nearly as general as blade failures. About half the utilities represented had experienced bearing damage incidents of varying severity. As with blade failures, these generally involved major outages for repair. The EEI data (Table 1-4) show this class of failure to cause a higher rate of full forced outage than any other turbine generator problem.

Bearing failures during normal operation are rare. One very serious case reported could have been averted if the unit had had an emergency power supply for the oil pump (which is normal practice) rather than only main electric pumps. Loss of auxiliary power resulted in lubrication failure. Though exceptional, this case demonstrates that lubrication is an aspect of the plant in which risks should not be taken for the sake of first cost.

If turbine-generator bearings fail, it is usually either during startup or, less frequently, during rundown. Most startup failures are caused by foreign material which is loosened or introduced into the lubrication system during construction or repair. Turbine makers usually specify stringent preservice flushing procedures which generally are followed after repair periods as well. However, it is clear from reports received at these meetings that flushing procedures frequently are inadequate. The reasons usually advanced were that pump capacity was inadequate to ensure an effective flush, and that boost pumps were not always available. It must also be accepted that flushing seldom can be completely reliable because foreign bodies can be trapped temporarily in the lubrication system or may be released from pipe surfaces after the flush.

Occasionally, bearings have been damaged by an attempt to turn a turbine on dry bearings. It is common practice (but not universal) to "float" bearings by injecting high pressure oil under the shaft before turning it. This obviously is good practice, but to be effective, the oil viscosity (temperature) must be controlled and oil distribution between bearings must be good. Damage to bearings during rundown also is usually related to oil temperature, which may result in viscosities being too low to eliminate metallic contact at lower speeds. Oil temperature control must be adequate at all conditions.

While the vendor has considerable concern for his product during normal operation, it is arguable that damage following a normal outage is attributable to the operator. As a result, lubrication problems at this critical stage often are not accepted as a vendor responsibility and seem to receive insufficient attention. Agreement is needed on filtration standards and oil cleanliness controls. Specifications are needed to provide guidance to utilities for both specifying and operating plants. There appear to be no appreciable technical problems involved, nor any insurmountable objections to improved lubricant filtration systems.

In some cases turbine vibrations were attributed to bearing deficiencies. There is a considerable problem in distributing the loads evenly between adjacent bearings and in aligning a shaft which may be 150 feet long. Most turbine bearings are simple journals. Tilting pads occasionally are used and perhaps should be explored for their greater stiffness and accommodation with respect to oil viscosity, clearance, and alignment.

Vibration

Severe turbine vibrations normally follow such events as blade failure or bearing damage. In other cases vibration may be a symptom of imbalance, a bowed or misaligned shaft, bearing design inadequacy, or foundation problems. The same types of problems arise in generators except for those related to blading. In addition, there is the possibility of electrical imbalance or feedback of electrical oscillations from the load system.

A proportion of the large total time attributed in the EEI report to vibration problems (Table 1-4) should be assigned specifically to blade or bearing causes. This could be the major portion.

Turbine balancing normally is not a lengthy process. However, in one case reported during the six meetings, repeated attempts were needed to achieve satisfactory operation. The difficulty appeared related to the overall layout and the stiffness of the turbine/generator bearing supports. Foundation design and stability are fundamental to good machine performance and are extremely difficult to rectify if inadequate. Accordingly, any possible connection of foundations with vibration needs investigation.

Another case which apparently was unique was related to extraction pipe supports in the condenser. On the whole, vibration incidents need more careful investigation to reveal root causes more clearly.

Water Induction

During normal operation, steam is bled from the turbine for feedwater heating. Unless the turbine is protected by adequate check valves, under some operating conditions a rapid change of turbine pressure relative to feedwater heater pressure can result in a flow of wet steam or water back into the turbine. This will damage the blading through excess mass loading or thermal shock. In extreme cases, the result can be a cracked rotor and/or casing damage.

Water induction damage has been fairly widespread in large turbines. Eight utilities reported such experiences, some having had repeated incidents. As a measure of the possible damage, four incidents resulted in outage times totalling 15,000 hours. One utility reported two of these incidents, each the result of a check-valve failure. In two other cases (including one of the most serious), water was injected in effect via the reheat steam supply as a consequence of incorrect desuperheater spray action or control. There appears to be a need for more effective control safeguards in this area.

No case of water induction was recorded in EEI data during the 1964-73 period; information on this problem was not collected before 1972.

Turbine Valves

Damage to turbine valves, ranging from erosion to stem breakage, was reported by about a third of the utilities attending the meetings. There is some evidence that the problems tend to be concentrated in the products of one vendor. In most cases these incidents caused less than 100 hours outage, but one outage exceeded 1000 hours.

One utility was forced to modify valve housings on two similar machines as the result of severe cracking. These two machines have experienced numerous shutdowns, with combined outage times more than 1400 hours. This type of damage is characteristic of cyclic thermal stress damage in thick metal sections.

In general, turbine valves may be particularly sensitive problem areas in cyclic plants. The high steam velocities lead to correspondingly high heat transfer coefficients and high cyclic stress damage. The EEI records show valve problems to have a moderate cost impact, with a large proportion of forced outage time.

Turbine Controls

Eight utilities reported miscellaneous failures of turbine control systems. About half the incidents appear to have been caused by leaks or contamination of the oil in electrohydraulic systems, with individual forced outage times around 100 hours. In other cases, numerous short outages were required to correct minor leaks or to correct electrical circuit faults. The average outage time recorded by EEI reflects this situation. While such problems do not incur major outage times, they are disruptive and cause undesirable thermal stress cycles in main plant components. Also, a failure while the turbine is not synchronized could have more serious consequences. Greater reliability might be obtained at relatively low cost by increased redundancy of control circuits or by better quality control.

Structural Features

The only recurrent structural problems of turbines reported at these meetings were control stage nozzle block failures, which appeared to be associated with a particular design. Four cases were reported, one of which had caused a six-month outage. In this case the problem appeared to have resulted primarily from faulty assembly. Other factors, such as erosion and probably steam induced vibration, also contributed. This design now has been modified by the vendor. It does instance the severe operational conditions in this area where erosion, thermal shock, low cycle thermal fatigue and high cycle fatigue mechanisms are all encountered. Hence, any design may prove sensitive to load cycling.

While there were only two reported incidents of turbine casing bolts failing or loosening, some concern was expressed over the lengthy and frequently difficult procedures needed to ensure tight joints without casing distortion or bolt damage and for disassembly of casings.

The EEI recorded virtually no outage time for the turbine HP end during the 1964-73 period, presumably because the reported prime failure cause was elsewhere. Major nozzle block failures appear to have occurred since this reporting period.

Generator Stator

There are substantial structural problems in the region of the end turns. They result essentially from an extreme mix of materials (copper, insulation, and iron) with widely different physical properties, subjected to very large alternating electromagnetic forces and differential expansion during load cycling. The most frequent precursors of failure are deterioration of insulating materials, which are physically the weakest elements in this combination, or cracking of conductors (the next weakest). In both cases the eventual mode of failure is through large scale electrical damage.

Regular checking and tightening of end turn supports provides some assurance of reliability, but it is clear that there is a need for better materials, designs, methods of construction, and on or off-line condition monitoring. It also appears that there is some difference between vendors in their respective ability to meet these needs.

Fourteen utilities reported generator stator problems, which in nine cases were responsible for major outages. Some reported stator problems were in water cooling systems. Minor leaks of connections or with conductors can lead to substantial electrical failures. Consequently, a very high standard of cooling system integrity is desirable, supported by effective on-line monitoring to detect leaks.

The number of major outages reported was greater than would have been expected from the EEI data. This suggests that stator incidents are relatively rare, but with characteristically long outage times for each event.

Generator Rotor

Rotor problems were only slightly less frequent than stator problems. Twelve utilities reported substantial total outage times. About half of these incidents were associated with the hydrogen cooling system. The EEI data (Table 1-4) confirms that seal failures are a major cause of generator outages, with long average outage times and a relatively high incidence rate. Less serious hydrogen system failures also are fairly common.

In two cases, rotor electrical breakdown caused outage times on the order of thousands of hours. Such a failure presents a substantial hazard, as damage can extend to the stator and be followed by fires or explosions. The EEI data appears to underestimate such problems, which are too infrequent to provide significant statistics.

Although only three failures were attributed to exciter faults, it is worth recording that one major utility keeps a mobile exciter to insure against lengthy outages from exciter electrical failure.

AUXILIARY SYSTEMS

Draft Systems

Resonant interactions with fans, or "organ pipe" resonance, can contribute to duct failure. The acoustic/dynamic characteristics of large ductwork seldom receive adequate design attention. Apart from failure, duct acoustics can cause noise emission problems, one case of which was mentioned during the discussions.

The most frequent and most serious cause of outage in draft systems is induced-draft fan failure. Erosion by fly ash is commonplace, and is greatly aggravated if precipitator performance is substandard. This can increase dust loadings by a factor of five to ten. Erosion, fouling, and distortion of the runner or shaft can cause vibration and eventual failure. I.D. fans need to be built with sufficient strength not to break up when run out of balance, as the operating conditions are always severe. Cycling duty imposes major temperature swings which can cause shaft distortion.

Seventeen utilities reported problems with draft systems. Of these, five reported damage to ducts which caused outages in the range of 100 to 300 hours per incident. Some of these already have been described as structural failures.

Other problems cited were failures of fan motors and drives and lack of draft capacity. A change of fuel type, particularily one that results in increased moisture and ash content, can overload fans and motors. The mass flow can increase by 5%, and local gas velocities also can be increased by ash accumulation in a duct. As fuel quality is expected to decrease even more, it is sensible to ensure that new boilers have both adequate fan capability and corresponding duct structural strength.

The EEI data (Table 1-3) confirms that fan problems constitute a high cost segment of forced outage, principally as partial outage. Most boiler units have two or three fans running in parallel at both FD and ID locations. They can operate with one fan out of service, either at full load or at reduced capacity. Although not shown separately in Table 1-3, induced draft fans are responsible for most fan-related outages.

Feed Water Systems

Feed water system problems were reported by 23 utilities.

Boiler Feed Pumps. Twenty utilities reported persistent feed pump problems. Failure modes cited included axial imbalance, vibrations, shaft bending or breakage, rotor breakage and cavitation damage. In seven cases there were also problems with pump drives (mostly with turbine driven pumps). Four cases of control instability were reported.

Feed pump outages are usually fairly short -- 10 hours or so when spares are on hand. In other cases, the return to service is limited by spare delivery times. In many cases, feed pump outages are persistent or repetitive.

The EEI data (Table 1-5) confirm that boiler feed pumps and their drives are one of the most costly sources of unit outage, with partial forced outages five times as frequent as full-forced outages. This reflects the practice of providing multiple feed pumps for each unit.

Feed pumps and their drives are very heavily loaded and operate over a relatively wide range of delivery conditions. It is often difficult to identify the root cause of a failure as parts may be badly damaged by secondary failures. EPRI recently completed a survey in this area which identified some serious design deficiencies that are being corrected. Some follow-up action will be needed to assess residual problems, which probably will include those related to control instability.

Feed Water Heaters. Ten utilities had significant, or even serious availability problems with feed heaters. Tubes failed from corrosion, fatigue, or fretting on supports. Vibration can be serious at locations where inlet steam impinges. In principle, feed water heaters can be isolated and repaired while the unit is operating. In many instances, however, safe isolation against steam and water at feed pump delivery pressure (3000-4000 psi) could not be achieved, which necessitated a complete unit outage for repair. The direct cost of feed water heater failures tends to overlook the contributions from loss of unit efficiency (if the heater is repaired with the unit on load) and secondary damage if the repair is delayed until a planned outage period.

The EEI data indicate that feed water heater problems have a much smaller impact than pump problems, but involve a greater proportion of forced outages. Most of these are partial outages, which reflects the ability to perform repairs with the heater isolated.

Valves

Sixteen utilities quoted valves as items which are generally unreliable. A substantial maintenance load seems to be accepted. Some utilities expect a high failure rate and the consequential repairs. In contrast, other utilities which overspecify valves appear to receive satisfactory service. The two valve types described as the most important from a reliability standpoint are feedwater heater isolation valves and boiler control valves (bypass and startup). Both types are subject to cavitation damage and rapid erosion by water or wet steam so that minor leaks develop quickly into large ones.

The mechanisms of damage to valves (and other components) by high pressure steam and/or water apparently have not been studied in detail. Erosion, cavitation, oxidation, and fatigue may all be involved. A better understanding might provide some new ideas for materials selection and design which could have very wide application. Damage during erection or distortion by external (pipe) forces may also contribute and might be addressed by imposing installation standards.

It is not possible to separate the full impact of valve problems from the EEI published data. The data indicate that boiler control valve problems alone constitute a moderately high cost outage cause, but this sector probably represents no more than half the total picture of valve problems.

Condenser Systems

There was less discussion of condenser problems during the six meetings than had been expected. Reference to the EEI data (Table 1-5) suggests a reason. Although condenser-related problems lead to high outage costs, most of the outages are scheduled. Tube leaks are a relatively minor item, both as reported in the meetings and as recorded by EEI. Condenser problems do not appear to be well documented, but the total costs involved certainly warrant a closer examination. EPRI is just concluding a major survey in this area which again addresses mainly the tube failure problem rather than the problem of maintaining condenser cleanliness without extensive downtime.

Coal and Ash Handling

Fifteen of the seventeen utilities which reported problems with coal and ash handling referred specifically to pulverizer performance as a source of difficulty.

Pulverizers. About half the reported cases of poor pulverizer performance were concerned with two particular designs. Subsequently, both had been modified very extensively and now are believed to be generally satisfactory.

The declining quality of coal supplies led to other problems with pulverizers apart from design weaknesses. At the resulting increased rates of coal consumption, many utilities found that their boilers required all pulverizers to be in service to carry full load. A forced outage of one pulverizer reduced unit output. Hence, proper maintenance schedules could not be met.

Inadequate pulverizer capability can produce severe secondary effects, some of which are apparent immediately. If coal particle size is larger than design, unburnt carbon will be carried from the flame zone, and either deposit and burn on the heat exchange surface or escape from the boiler as a combustion loss. Deposited carbon exacerbates any tendency to slag, and leads to a chemically reducing local environment which can cause corrosion. Such events were described earlier in the discussion of boiler problems. At least two utilities recognized a connection between pulverizer performance and boiler slagging.

Any successful modifications to existing pulverizers, or the conditions under which they operate, could therefore pay substantial returns. The measures taken to redesign and rebuilt the two troublesome designs mentioned at the beginning of this section demonstrate that significant improvements may be possible. In such cases, the cost of modifications can be substantial.

The EEI data show pulverizer problems in the high cost category, mostly through partial forced outages. The situation now may be improved by the design modifications previously mentioned. On the other hand, the statistics do not account for the total impact which often includes appreciable secondary effects.

Coal Handling. Difficulties with feeding and handling coal were especially apparent where wet and freezing conditions are common. These are not new problems, and there are perhaps no new solutions. The results from a handling test should be an important consideration in the purchase of a coal supply. One instance was quoted of coal which presented no problem when freshly mined and dry, but which hydrated strongly on exposure to damp conditions and quickly assumed the consistency of clay. Many coal handling problems are the result of a reluctance to invest in equipment which may be required only during exceptional weather.

The use of slurry pipelines for conveying coal is being studied. Slurries are both erosive and corrosive. Although experience is limited, trouble-free dewatering of large tonnages of coal seems to require more attention than it has received.

Ash Handling. Although fewer problems with ash handling were reported than coal handling problems, many ash handling plants are crude and require excessive maintenance. The main problems were associated with removing ash from boiler hoppers, the most critical part of the operation from the boiler operator's viewpoint.

The EEI data (Table 1-3) show that both coal handling and ash handling are moderately high cost problem areas. Practically all outages attributed to them are forced outages, probably because most of the extensive maintenance required is performed during general down time. Since the same technologies are involved in handling either coal or ash, a concerted development effort seems warranted, especially in view of the larger tonnages of coal expected to be burnt in the future.

SHAKEDOWN

In reviewing experience with units of over 600 MW capacity, it must be conceded that the EEI records for 1964-73 cover a period of rapid growth in this size range. This is well illustrated by the fact that the 203 unit-years included in the records for the ten year period would represent little more than two years' experience for the units operating today.

The extent to which the records represent mature plants is questionable. It is generally accepted that availability of new plants increases during the period of initial operation. At the six regional meetings, many utilities reported satisfactory performance after the first few years.

The extent of the need to introduce major design, structural, and functional modifications during the early years of a unit's operation should also be questioned. New generating plants tend to be custom made in many respects, ostensibly because of special local circumstances. However, each one represents a major event in the careers of the utility engineers, designers, and architect engineers who are responsible for it. The plant is therefore an expression of several individual personalities and ambitions.

For this reason, and because of continuous technical advances, there is less reliance on proven design than is desirable. Problems have resulted from modifications to established practice without proper design background or experimentation. The necessary development work is then done during shakedown at utility expense.

Correspondingly, there is an increased need for a thorough understanding of design principles, for close supervision during construction, and for component testing. Some experiences reported by different utilities illustrate inadequacies in plant which might have been avoided by one or another of these routes.

Although necessary repairs or corrections are classed as planned outages, it is generally not possible to schedule outages upwards of 500 hours without incurring increasingly severe replacement power costs. All long outages therefore should be classed as "forced" so far as their economic effect is concerned.

Design

Several instances were reported of necessary extensive changes to boiler surfaces, such as removal of considerable areas of superheater or reheater. Inability to predict detailed heat transfer behavior is an old problem which reflects the customary empirical approach to design, which tends to fail when boiler layout or size is changed or when new fuels are encountered. Corrections during the early years of boiler operation are expensive, require long outages and are not always effective.

Water carryover in drum boilers is another characteristic which depends on empirical design approaches. Economies in drum size have increased carry-over with detriment to steam purity and turbine life. Both water carry-over and boiler surface design areas require systematic investigation to provide a more dependable design base.

Boiler structural design presents major analytical difficulties, complicated by the need for flexibility to accommodate thermal expansion. The different structural behaviors of membrane wall and tangent tube furnaces seem to have been underestimated. Similarly, pressurized furnaces were adopted in coal-fired units without proper consideration for leakage and erosion problems. Many utilities have incurred heavy costs in reverting to the proven balanced draft system.

The horizontal shaft air heater which was introduced almost entirely on economic grounds is basically a questionable concept. It introduced severe structural problems which may not be economically solvable, and which should have been obvious.

Problems associated with furnace-to-convection pass heat transfer balance, and a variety of control problems (some connected with implosions) suggest that the analytic models of performance need to be improved. Physical models could be used to resolve aerodynamic problems which contribute to poor precipitator performance, economizer erosion, and heat transfer maldistribution.

All of the foregoing items have appeared in different degrees as shakedown problems. In fact they are the results of design changes which were made on the basis of inadequate analyses of their effects.

The continuing existence of turbine blade fatigue failures is disturbing. This subject requires very sophisticated analysis, but a satisfactory trade-off between blade strength and aerodynamic performance appears possible. It would be a step forward if utilities could avoid the need to open turbines for lengthy first-year inspections, either as the result of greater design confidence or through improved systems of monitoring and inspection.

Testing

Full scale testing of complete generating units requires the construction of a prototype power station. However, major secondary components which go into series production--feed pumps, feed pump turbines, pulverizers, fans, circulating pumps, and valves--could be tested in prototype form on existing plant before full-scale adoption on new plant. This could save large blocks of forced outage time.

During discussions with utilities, many referred to design extrapolations in such components, which is a reasonable description of the way that unit capacities are increased. There were several cases in which redesign and on-site rebuilding of large components were necessary. Extrapolation of empirical designs is dangerous, since it does not recognize the possibility of critical discontinuities in basic physical phenomena. If the underlying physical basis is in any way inadequately understood, testing is essential.

Supervision of Site Work

Close supervision of site construction is difficult, as is control of working conditions. Where possible, therefore, factory or indoor fabrication should be maximized. Because it is more difficult, site work needs more careful supervision and testing. Cases were recorded of multiple boiler tube failures following site modifications (which would not have been necessary if the original design had been correct). Outages also were caused by partial blockage of tubes by debris. Although repairs were effected, such occurrences can cause metallurgical damage which contributes to future outages. There are methods available for detecting tube blockages, which could be used after repair periods or other outages.

More serious damage was caused by tools left in generators. There is a great deal of manual assembly work in this area, and the possibility of mishaps of this sort is above average. Since the risk is so great, improved supervision and inspection are essential.

Quality deficiencies were reported even for factory-made components. Welding standards applied to nonpressure parts appear to be variable and sometimes indifferent.

While the above remarks may appear critical of vendors, the utilities have very important contributions to make to resolve these problems. Apart from the obvious need to feed back failure data (which is usually done), these include the need to express their requirements in meaningful and explicit specifications, and to set performance standards that can be measured.

Section 3

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

In general, this study confirms that the outage data provided by the Edison Electric Institute for large generating plants provide both a background and justification for a research program to improve reliability.

The six informal meetings with major utilities gave some useful substance to the published statistics, and will help to focus on specific plant areas. However, the findings were too general to lead to a close definition of failure causes in most cases.

The total annual outage costs for all fossil-fired units of over 600 MW capacity is estimated to be at least $750 million*. It seems reasonable to aim for an improvement of availability for this class of plant from the present level of 73% to around 80% which is characteristic of smaller units. If achieved, this would have an annual worth of at least $150-200 million for presently installed capacity and capacity nearing completion.

The cost of design and operational changes to achieve this target has not been estimated, although by comparison the cost of the related research is very small. Neither is it clear at this point whether this is the appropriate target, as the cost effectiveness of added improvements to plant will certainly fall progressively.

The plant problems requiring priority consideration are listed below. Research programs may need to be oriented slightly differently to include related but

*The simple analysis on which this figure is based was adopted more for purposes of comparison than to provide an accurate total, and it could be low by a factor of two.

more basic underlying topics, and to reflect the probability of success within a reasonable time and cost.

Boiler

Waterwall Tube Failures. Many contributory causes, including design, operational (combustion and water treatment) and structural elements.

Superheater and Preheater Tube Failures. Various causes; materials operate in creep regime with added complication of cyclic stress, internal and external corrosion. Exfoliation problem is related.

Slagging and Fouling. Often symptoms of design or equipment inadequacies, but sometimes capable of amelioration by changes in operation; frequently has major site specific aspects.

Boiler Control. Problems have a moderately high direct impact, but are important because of secondary effects (materials, water carryover), safety aspects (explosions and implosions), and efficiency.

Turbine Generator

L.P. Turbine Blading. Requires sophisticated design approach, materials subject to extreme fatigue risk, probably corrosion. Forced outages of long duration, with risk of secondary damage.

Bearings and Lubrication. Failures require long outages for correction; no apparent weakness of technical base, but need for improved design and operational safeguards.

Generator Seals. Mostly hydrogen coolant seals; incidents carry fire/explosion risk and require long repair times.

Generator Windings. Support and structural failures more common than indicated by EEI statistics; characteristically very long and damaging incidents; likely to become worse with cycling.

Auxiliary Systems

Fans. Main problems with induced draft fans, which are subject to erosion, corrosion, thermal cycling; requires exceptional construction and installation standards.

Feed Pumps. Problems are largely design related; further review needed as basis for better specifications and preservice testing.

Valves. Performance of commercial products very variable and failures affect major plant components; scope for improved specification and tests for utility applications; basic technology may be weak.

Condensers. Major outages scheduled; test and maintenance schedules may need review (detailed review in progress).

Pulverizers. High direct costs, problems affect performance of major plant components and other problem areas (tube failures, slagging and fouling); some major design-related problems suggest that technology may be inadequate.

RECOMMENDATIONS

Additional work is needed to increase the reliability and availability of large fossil fuel power plants. Specific subject areas for this work are summarized in the preceding conclusions. The research and development needed to achieve these improvements should include the following types of inquiry and actions:

- Where major causes can be traced, research projects should be initiated to address the foregoing problems.
- Specific failure cause analysis studies should be initiated where major outage causes cannot be identified clearly.
- Failure cause analysis studies should consider especially those weaknesses in scientific knowledge or technology which affect several problem areas.

- Where failures are directly design related, EPRI should assist both utilities and vendors by documenting the available information and by improving the relevant specification standards.

- Where specification guidelines are provided, test and quality assurance provisions should also be made.

- EPRI should work closely with established bodies such as ASME, IEEE, and the EEI Prime Mover's Committee in the preparation of specification guidelines.

- Where weaknesses in scientific knowledge or technology are evident, EPRI should support relevant work to remedy the deficiency.

- More recent EEI data should be examined to ensure that any changes in outage patterns are noted.

Appendix

UTILITIES REPRESENTED AT EPRI-ORGANIZED MEETINGS

Atlanta

Carolina Power & Light Company
Duke Power Company
South Carolina Electric and Gas
Southern Company Services, Inc.
(representing Georgia Power Co., & Alabama Power Co.)
Tennessee Valley Authority
Virginia Electric & Power Company

Cleveland

Allegheny Power Service Company
Columbus & Southern Ohio Electric Company
Detroit Edison Company
Ohio Edison Company
Cleveland Electric Illuminating Company

Houston

Louisiana Power & Light Company
Mississippi Power & Light Company
Texas Power & Light Company
Houston Lighting and Power Company

St. Louis

Commonwealth Edison Company
Illinois Power Company
Kansas City Power & Light Company
Public Service Company of Indiana
Union Electric Company

New York

American Electric Power Company
Boston Edison Company
Consolidated Edison Company of New York
(also representing Orange and Rockland)
Pennsylvania Electric Company
New England Electric System
Pennsylvania Power & Light Company
Potomac Electric Power Company
Public Service Electric & Gas Company

San Francisco

Arizona Public Service Company
Pacific Power & Light Company
Southern California Edison Company
Pacific Gas & Electric Company