

STEAM PLANT SURFACE CONDENSER LEAKAGE STUDY

EPRI NP-481
(Research Project 624-1)

Final Report

Volume I

March 1977

Prepared by

BECHTEL CORPORATION
P. O. Box 3965
San Francisco, California 94119

PROJECT ENGINEER
Walter B. Lawrence

PRINCIPAL INVESTIGATORS

William D. Ellis
Frederik J. Hekking
Michel P. Lagache
Aswath M. Maddagiri
A. Charles Madsen

Prepared for

Electric Power Research Institute
3412 Hillview Avenue
Palo Alto, California 94304

EPRI Project Manager
William L. Lavalley

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

FOREWORD

Tube failures in steam plant surface condensers are a significant reliability problem which continues to confront the electric power industry. Part of the impact of condenser leakage can be measured by the replacement power costs experienced by large base load units as a result of outages to repair condenser leaks. Another aspect of condenser leakage impact which is much more difficult to measure is the potentially harmful effects of leakage on other major components such as steam generators and turbines.

In an effort to provide the power industry with useful information to use in assessing condenser leakage problems, the Electric Power Research Institute contracted Bechtel Corporation to conduct this "Steam Plant Surface Condenser Leakage Study."

There are numerous variables which can affect the leakage integrity of a condenser, too numerous for them all to be addressed with the limited amount of data available to the writers of this report. These variables result from such things as differences in plant operating philosophies, environmental differences to which the condenser components are exposed, and differences in designs and materials. Because of this, plant operators should view the conclusions reached in this report as general considerations to be used as starting points for reaching decisions on specific requirements for their condensers. The failure rate probabilities presented in this report for various tubing materials serve as a useful means for summarizing the tube failure experience of the units participating in the field survey. Although care was taken in selecting the sample of units surveyed as is explained in the report, no attempt has been made to show that the sample is statistically representative of the entire population. Such statistical treatment was not considered necessary since the failure rate probabilities are not being portrayed as generic to the various tubing materials, but only as a means for making relative comparisons among the materials surveyed.

Field surveys of this type are useful in collecting certain kinds of information, but there are areas which are not readily assessable via this method. For example, the report indicates that there were no demonstrated cases of severe damage to other components in the steam cycle as a result of condenser leakage. Without detailed failure analyses, the effect of condenser leakage on other components can not be objectively verified, but there is considerable evidence to indicate that such leakage does have detrimental effects specifically in the case of PWR steam generators.

This report has demonstrated that operating power plant experience is extremely useful in assessing equipment performance. However, this plant experience can only be derived as a result of effective records keeping on the part of the plants.

William L. Lavallee
Project Manager



ABSTRACT

This report presents the results of a study to determine the factors which affect the deterioration and subsequent leakage of main surface condenser tubes in electric power plants. The report addresses several areas related to condenser tube leakage, including design, materials, chemistry, operation, and maintenance. The data on which the report is based was obtained through field trips to operating power stations, mail questionnaires, and a literature search. The field survey concentrated on large fossil-fueled plants, nuclear plants, and plants having condensers tubed with titanium. Much emphasis was placed on presenting tubing failure information as a function of tubing material, cooling-water conditions, failure mechanisms, condenser design, and several other parameters. Information is also presented on the criteria for retubing condensers, and recommendations for future work pertaining to condensers is discussed.

ACKNOWLEDGMENTS

This study could not have been done without the interest and cooperation of the organizations contacted by the study team. EPRI and Bechtel wish to acknowledge the excellent cooperation afforded us throughout the industry. For their generous contributions of time, records, and counsel, we are especially grateful to the personnel of the utilities who operate the 30 stations that were surveyed in the field.

The Bechtel study team was under the direction of Walter B. Lawrence, Project Engineer, who was responsible for the conception and overall execution of the study program. He prepared Sections 1, 2, 3, 6, 7, and the last two parts of Section 5 for the final report.

William D. Ellis, Senior Engineer, as the full time participant of the study team, was responsible for the day-to-day execution of the project and was the lead engineer of the field survey teams. He also handled all computer applications and data processing and contributed to all sections of the final report as well as preparing the sections on titanium alloy tubes and records keeping.

Michael F. Lagache and Aswath M. Maddagiri, Engineering Specialists, contributed their engineering experience throughout the project. Both participated heavily in the field survey work. Mike Lagache prepared Section 4.

A. Charles Madsen, Senior Metallurgist, gave expert guidance in his specialty as well as full participation in the field surveys. He prepared most of Section 5 of the final report.

Frederik J. Hekking, Senior Engineer, conducted all aspects of the literature survey from the initial searches to the final printout of the bibliography by the use of the computerized indexing system he devised.

Ted N. Levine adapted the commercially available System 2K data management software package to the requirements of the project, and instructed Bill Ellis in its use.

Simone A. Linares, Project Administrator and Secretary, served with commendable skill and resourcefulness.

The contract administrator for the first nine months was H. R. Mank who was succeeded by William L. Cady. The two contract administrators conducted all contractual matters including accounting and financial reporting.

Appreciation is also expressed to Mr. J. A. Prestele and Dr. Donald Anson for their suggestions and comments on the preparation of this report.

CONTENTS

<u>Section</u>		<u>Page</u>
1	INTRODUCTION	1-1
	Statement of the Problem	1-1
	Study Objective	1-2
	Scope of Work	1-2
2	CONDENSER FUNCTION, DESIGN, AND OPERATION	2-1
	Purpose of the Condenser	2-1
	Condenser Configuration	2-2
	Condenser Design Considerations	2-9
	Maintenance of Tube Cleanliness	2-22
3	METHODOLOGY OF THE PRESENT STUDY	3-1
	Introduction	3-1
	Literature Survey	3-1
	Matrix for Selection of Field Survey Stations	3-6
	Mail Survey	3-7
	Field Survey	3-10
	Data Management System	3-19
4	CONDENSER OPERATION AND MAINTENANCE FINDINGS	4-1
	Introduction	4-1
	Circulating Water Inleakage	4-1
	Air Inleakage	4-17
	Other Operation and Maintenance Considerations	4-22
5	PERFORMANCE OF CONDENSER TUBE ALLOYS	5-1
	Introduction	5-1
	Copper-Base Alloys	5-12
	Stainless Steels	5-31
	Titanium	5-39
	Summary of Performance	5-57

<u>Section</u>		<u>Page</u>
6	CONCLUSIONS	6-1
	Performance of Condenser Tube Materials	6-1
	Condenser Retubing Criteria	6-3
	Impact of Condenser Leakage	6-4
7	RECOMMENDATIONS	7-1
	Short-Term Work	7-1
	Middle-Term Work	7-2
	Long-Term Study	7-2
 <u>Appendix</u>		
A	Bibliography by Number	A-1
B	Bibliography by Author	B-1
C	Keyword Listing	C-1
D	Mail Survey Form	D-1
E	Station Selection Matrix	E-1
F	Descriptions of Information Fields in Station Selection Matrix	F-1
G	Field Survey Form	G-1
H	Field Survey Matrix Descriptors	H-1
I	Field Survey Matrix	I-1

LEGAL NOTICE

This report was prepared by Bechtel Corporation, as an account of work sponsored by the Electric Power Research Institute, Inc. (EPRI). Neither EPRI, members of EPRI, Bechtel, nor any person acting on behalf of either: (a) makes any warranty or representation, express or implied, with respect to the accuracy, completeness, or usefulness of the information contained in this report, or that the use of any information, apparatus, method, or process disclosed in this report may not infringe privately owned rights; or (b) assumes any liabilities with respect to the use of, or for damages resulting from the use of, any information, apparatus, method, or process disclosed in this report.

ILLUSTRATIONS

<u>Figure</u>		<u>Page</u>
2-1	Steam Water Cycle	2-3
2-2	Single-Pass Surface Condenser	2-4
2-3	Single Pressure, Dual-Shell Condenser Design	2-6
2-4	Single Pressure, Three-Shell Condenser Design	2-6
2-5	Triple-Pressure Condenser with Long Tube Bundles	2-7
2-6	Triple-Pressure Condenser	2-8
2-7	Single-Pressure Condenser with Central Cold Water Entrance	2-8
2-8	Heat Transfer Rate When $F_1 \times F_2 \times F_3$ is 1.0	2-10
2-9	Correction to "U" for Cooling Water Inlet Temperature	2-10
2-10	Flow Distribution over Area of the Exhaust Connection	2-13
2-11	Tubesheet Configuration Designed for Steam Entry All Around the Tube Bundle	2-14
2-12	Noncondensable Gas Collection in Single-Pass Rectangular Surface Condenser	2-15
2-13	Noncondensable Gas Collection in Two-Pass Rectangular Surface Condenser	2-16
2-14	Shrouded Air Removal Section for Cascaded Removal of Noncondensibles	2-17
2-15	Location of Shrouded Air Removal Section of Tube Bundle	2-18
2-16	Typical Tube-to-Tubesheet Joints	2-23
2-17	Typical Installation, Amertap Condenser Tube Cleaning System	2-25
2-18	MAN System for On-Line Cleaning of Condenser Tubes	2-26
2-19	MAN On-Line Cleaning System for Condensers and Tubular Heat Exchangers	2-27

<u>Figure</u>		<u>Page</u>
3-1	Typical Catalog File Card	3-3
3-2	Mail Survey Results of Condenser-Related Records	3-11
3-3	Data Management Matrix	3-21
4-1	Condenser Retubing Work Area	4-3
4-2	Condenser Retubing-Tube Pulling Operation	4-3
4-3	Plants Surveyed that Achieve a Given Condenser Water Leakage Detection-to-Localization Rate	4-6
4-4	Cation Conductivity Instrument Resin Columns	4-8
4-5	PWR Plants Surveyed that Detect Condenser Water Leakage at a Given Bulk Condensate Impurity Content	4-9
4-6	Fossil Plants Surveyed (>150 MWe) that Detect Condenser Water Leakage at a Given Bulk Condensate Impurity Content	4-10
4-7	Air and Water Inleakage Rates for a Condenser with 1.7 inch Hg Backpressure	4-12
4-8	Typical Tube Inserts (upper left) and Plugs (lower right)	4-15
4-9	Typical Tube Insert Setup	4-16
4-10	Equilibrium Noncondensable Partial Pressure and Equilibrium Condensate O ₂ Content from Air Inleakage vs Condenser Total Pressure and Sub-cooling	4-21
4-11	Typical Circulating Water System for Twin Shell Condenser and Open Cycle or Cooling Lake	4-24
4-12	Typical Characteristics of Low-Head Circulating Water Pumps	4-24
4-13	Typical Characteristics of Medium Head Circulating Water Pumps	4-25
4-14	Typical Cathodic Protection Electrodes	4-30
4-15	Typical Tube Cleaning Devices	4-30
5-1	Failure Rate vs Probability Curves for Admiralty Brass in Freshwater Service. Curves for Main-Body Service (M) (66 Tubesets) and the Air Removal Section (A) (34 Tubesets) are Shown.	5-15
5-2	Failure Rate vs Probability Curves for 90-10 Cu-Ni in Freshwater (17 Tubesets) and Seawater Service (56 Tubesets)	5-20

<u>Figure</u>		<u>Page</u>
5-3	Failure Rate vs Probability Curves for 90-10 Cu-Ni in Seawater Service, With (29 Tubesets), and Without (29 Tubesets) FeSO_4 Additions.	5-23
5-4	Failure Rate vs Probability Curve for 70-30 Cu-Ni in Seawater (51 Tubesets, of Which 6 are Main Body and 45 are Air Removal).	5-25
5-5	Failure Rate vs Probability Curves for 70-30 Cu-Ni in Seawater With (24 Tubesets) and Without (33 Tubesets) FeSO_4 Additions.	5-27
5-6	Failure Rate vs Probability Curve for Aluminum Brass in Seawater (37 Tubesets)	5-28
5-7	Failure Rate vs Probability Curves for Aluminum Brass in Seawater Service With (4 Tubesets) and Without (32 Tubesets) FeSO_4 Additions.	5-30
5-8	Failure Rate vs Probability Curve for Aluminum Bronze in Seawater Service (12 Tubesets)	5-32
5-9	Failure Rate vs Probability Curves for Type 304 Stainless Steel in Freshwater Service; Curve A-A and M Tubesets (Guard Plugs at One Station Deleted) (64 Tubesets); Curve B-A and M Tubesets (No Exclusions); Curve C-I Tubesets (27 Tubesets).	5-35
5-10	Failure Rate vs Probability Curve for Type 304 Stainless Steel in Cooling Tower Service (13 Tubesets). (Note: As explained in the text, this curve may be misleading).	5-37
5-11	Failure Rate vs Operating Hours and Failure Rate vs Probability for Titanium Tubing	5-44
5-12	Failure Rate vs Operating Time for Main-Body Tubesets in Fresh Water	5-61
5-13	Failure Rate vs Operating Time for Main-Body Tubesets in Seawater	5-65

TABLES

<u>Table</u>		<u>Page</u>
2-1	Design Correction Factors for Condenser Tubing Materials (F_2)	2-12
3-1	Typical Computer Search History	3-2
3-2	Literature Search Keyword List	3-4
3-3	Station Selection Matrix - Age Distribution by Fuel Type	3-9
3-4	Station Selection Matrix - Condenser Tube Material by Cooling Water Category	3-9
3-5	Field Survey Stations - Age Distribution by Fuel Type	3-12
3-6	Field Survey Stations - Condenser Tube Material by Cooling Water Category	3-13
3-7	Field Survey Stations - Age Distribution by Generator Size	3-14
3-8	Comparison of Station Selection Matrix with Field Survey - Age Distribution by Fuel Type	3-15
3-9	Comparison of Station Selection Matrix with Field Survey - Condenser Tube Material by Cooling Water Category	3-16
3-10	Comparison of Station Selection Matrix with Field Survey - Distribution by Condenser Manufacturer	3-17
5-1	Distribution of Tubesets by Material and Water Type	5-5
5-2	Tubeset Failure Rate Calculation Sheet	5-8
5-3	Distribution of Tubesets with Known Failure Rates by Material, Condenser Service, and Water Type	5-9
5-4	Distribution of Number of Tubes and Condensing Surface Area by Material and Water Type	5-10
5-5	Copper-Base Alloys, Chemical Composition and Designation	5-13
5-6	Contributing Failure Mechanisms for Admiralty Brass in Freshwater	5-14

<u>Table</u>		<u>Page</u>
5-7	Relationship Between the Shrouded-Unshrouded Ratio, R_s , and Failure Rate	5-17
5-8	Contributing Failure Mechanisms for 90-10 Cu-Ni in Seawater	5-22
5-9	Contributing Corrosion Failure Mechanism for 70-30 Cu-Ni in Seawater	5-24
5-10	Contributing Corrosion Failure Mechanisms for Aluminum Brass in Seawater	5-29
5-11	Contributing Failure Mechanisms for Aluminum Bronze	5-31
5-12	Stainless Steel, Chemical Composition and Designations	5-33
5-13	Contributing Failure Mechanisms for Type 304 Stainless Steel in Fresh Water	5-38
5-14	Maintenance and Cleaning Procedures Used for Type 304 Stainless Steel Tubing	5-40
5-15	Field Survey Data, Titanium and Vibration	5-48
5-16	Field Survey Data, Titanium and Its Galvanic Environment	5-56
5-17	Comparative Performance of Condenser Tube Materials in Open Freshwater Cooling Systems	5-59
5-18	Comparative Performance of Condenser Tube Materials in Open Salt-Water Cooling Systems	5-63
5-19	Comparative Performance of Condenser Tube Materials in Closed Cooling-Water Systems	5-68

SUMMARY

Condenser tube leakage has an impact on the operating cost, availability, and useful service life of power generation facilities. Aware of this, EPRI contracted with Bechtel Corporation to conduct a broad study of the factors that affect the deterioration and subsequent leakage of condenser tubes. The results of the study are given in this report.

The objective of the study was to provide the electric utility industry with valuable guidelines for selecting and operating condensers and to highlight areas that require increased research and development effort.

The study consisted of three broad tasks:

- A field survey of the condensers at 30 power stations with 76 generating units
- A literature search which resulted in a bibliography of 391 references pertinent to the study
- Analysis of the survey and literature data and the preparation of the final report

Selection of the 30 stations for field survey was based on an analysis of 87 items of information relative to the design, operation, and performance of condensers at 87 power stations with 264 generating units. The information in this selection matrix was compiled from the literature, government reports, Bechtel files, and the results of a questionnaire mailed to the stations. The selection process and the pertinent characteristics of the 30 stations surveyed as compared to the profile for large, modern power generating units which was developed by the selection matrix are described in Section 3.

A computer-based data management system was developed to enable efficient processing of the hundreds of thousands of information items collected in the course of the study.

Highlights of the findings of the study are summarized below.

The major impact of condenser leakage is the value of the power generation lost while the unit is at part load or off line to repair the leaks. No generally applicable cost figures could be determined because of the wide variation in the costs assigned to lost generation by the various utility systems dependent upon the unit down, the time at which it was down, the system load at the time, etc. No demonstrated case of severe damage to any components in the turbine cycle due to condenser leakage was found at the 30 stations surveyed.

Very small condenser leaks can be detected by analysis of the water chemistry of the turbine cycle. Nearly all of the generating units surveyed have on line, automatic analyzers for this purpose. The ability to locate the leak within the condenser is not as sensitive as the available detection methods. However, most plants are able to locate and repair any detectable leak. Hydrotesting the steam side of the condenser was usually reported to be the most sensitive method of leak localization. Another commonly used method is the application of either plastic film or foam to the tubesheet of the evacuated condenser. There was no agreement at the surveyed stations about which of these two methods is the more sensitive. The impact of condenser leakage and the detection, location, and repair of condenser leaks are discussed in Section 4.

Quantification of the performance and probable service life of condenser tube materials was obtained by numerical analysis of the extensive condenser service histories acquired by the study. The performance of common condenser tube materials in various environments is expressed numerically by a failure rate (FR), which is the percentage of tubes plugged per 10,000 hours of operation. The probability of attaining a specific failure rate is calculated from the data base for each alloy, in each environment considered. From these probability calculations, an estimate can be made of the anticipated service life the condenser tube material will have in the stated environment. The exposure environment is defined in terms of three circulating water categories and three condenser service sections. The circulating water categories are: 1) fresh water once-through; 2) salt water; and 3) closed concentrating systems that use fresh makeup water. The condenser service sections are: 1) impingement section; 2) main condensing section; and 3) air removal section.

It was found that, in the main condensing section of freshwater cooled condensers, all of the commonly used materials have a high probability of lasting the plant lifetime without retubing. In the air-removal section, however, admiralty tubes do not give satisfactory service.

For the condensing section of saltwater cooled condensers, it was found that of the materials surveyed only titanium has a high probability of lasting the plant lifetime without retubing. Aluminum brass, aluminum bronze, and 90-10 Cu-Ni have a less than 50-percent probability of attaining a failure rate less than 0.33, which corresponds to 40 years of service with 10 percent of the tubes plugged.

Not enough information was obtained to allow a definitive evaluation of the performance of the various condenser tube materials in closed cooling systems. There is an indication that admiralty condenser tube performance is poorer in closed systems than in open freshwater systems. Stainless steel condenser tubes appear to give equally good service in both cooling modes.

From the accumulated data on condenser tube performance, an easily applied criterion was derived to determine when a condenser is a candidate for retubing. When the percentage of tubes plugged exceeds $\sqrt{H}/100$ (where H is the total operating hours on the existing condenser tubes), a future retubing is likely.

Details of condenser tube performance are given in Section 5. A comparative summary of the performance of the various condenser tube materials in the different environments is given at the end of Section 5.

The conclusions of the study are briefly summarized in Section 6 and the recommendations for future work are listed in Section 7.

Section 1

INTRODUCTION

STATEMENT OF THE PROBLEM

Condenser tube leakage has an impact on the operating cost, availability, and useful service life of power generating facilities. Failure of condenser tubes introduces circulating cooling water into the pure condensate and may thereby contaminate the entire steam-water cycle. The degree of contamination is a function of the rate of inleakage and the composition of the cooling water.

Two trends in power plant design and operation have further intensified the impact of condenser tube leakage.

- The Environmental Protection Agency's 1974 Effluent Guidelines and Standards for Steam Electric Power Stations (40 CFR 423) have caused most new (and some existing) power stations to use cooling towers or ponds for main condenser cooling in place of once-through cooling. The resultant higher dissolved solids in the cooling water and the generally higher pressure on the condenser waterside magnify the contamination introduced by condenser tube leaks.
- All U.S. manufacturers of PWR nuclear steam supply systems now recommend the use of only volatile chemicals in secondary or turbine cycle water treatment. Consequently, the introduction of circulating cooling water into the condensate by condenser inleakage will result in scale formation and/or increased corrosion in the steam generators. Only minute quantities of inleakage can be tolerated before the stringent limitations on feedwater or steam generator water quality are exceeded and the plant must be shut down.

Condensate demineralization can extend the rate of inleakage that can be tolerated before plant shutdown is required, but adds significantly to capital and operating costs. There is also concern that, under certain circumstances, condensate demineralizers will adversely affect water quality by sodium contribution.

All of these considerations, together with the high cost of even a single day's outage for modern large power plants, indicate how important it is to take all reasonable measures to minimize condenser tube leaks.

The efforts of the industry to alleviate or eliminate condenser inleakage have been hampered by the paucity and fragmentary nature of available information on the frequency, size, and duration of condenser leaks; on the anticipated service performance and life of various condenser tube materials over the applicable range of exposure conditions; on the effect of condenser design and construction parameters; on the sensitivity and accuracy of various methods for the detection and location of condenser leaks; and on the best procedures for repairing leaks with the minimum loss of power generation.

Aware of this problem, the Electric Power Research Institute (EPRI), in November 1975, contracted with Bechtel Corporation to conduct a broad study of the factors that affect the deterioration and subsequent leakage of condenser tubes.

STUDY OBJECTIVE

As stated in the contract, the prime objective of this study is to "provide the industry with valuable guidelines for selecting and operating condensers and to highlight areas which require increased research and development effort."

SCOPE OF WORK

The scope of work comprised three broad tasks:

- A field survey of existing power plant condenser systems
- A literature search and preparation of a bibliography of references pertinent to this study
- Evaluation of the technical information so collected and preparation of a final report with conclusions as well as recommendations for further investigation.

To accomplish these tasks the work of the project was subdivided into the following five phases.

1. Project Organization and Control

Upon award of contract the project was staffed with qualified, experienced personnel. A detailed task flow diagram was constructed to delineate and interrelate each task and subtask required to accomplish the prescribed work. From this, a critical path schedule was derived and became the basis for schedule and budget control throughout the project. Communication and reporting channels between EPRI and Bechtel were defined. Progress reports and progress meetings were scheduled at appropriate intervals.

2. Field Survey

Shortly after project inception, a 30-page field survey form was developed. To guide the selection of stations for field survey that would constitute a representative sample, a matrix of design and operating data was prepared for 87 stations with 264 generating units. The input data for this selection matrix were compiled from a mail survey of the stations, published reference material, and Bechtel records. The field survey covered 30 stations with 76 generating units. A computer data management system was established to enable analysis and evaluation of the data obtained from the field, mail, and literature surveys.

3. Literature Search

The initial effort was a search of the computerized portions of the Engineering Index and the National Technical Information Service Index. This was followed by a manual search of these and other indices and a cross-check of the references listed in the discovered articles. Two listings of the bibliography of 391 references were prepared - alphabetically by author and numerically by accession number. A keyword list was prepared for the articles in the bibliography. Additionally, numerous unpublished articles and catalog items were accumulated and indexed.

4. Evaluations and Conclusions

The data and information collected by the mail, field, and literature surveys were evaluated and analyzed primarily by use of the computerized data management system and prepared for inclusion in the final report. Conclusions and recommendations were formulated.

5. Final Report

This report presents the results, findings, conclusions, and recommendations that resulted from the study. A brief description of the contents of the report is given in the following paragraphs to guide the reader.

Section 2 is a comprehensive review of the state of the art of main surface condensers in power generation stations. The section describes the purpose and configuration of condensers, discusses the more important design aspects and parameters, and reviews the significant operating problems. No results from the field survey program are included in this section.

Section 3 describes the methodology employed to accomplish the scope of work. The technique and results of the literature search are described. The mechanics for selection of the stations for the field survey are described, and the validity of the selected sample is evaluated. The conduct of the field survey and the data sought are discussed. The data management system developed to process and analyze the collected data is explained. No results from the field survey program are given.

Sections 4 and 5 present the results and findings of the mail and field survey. Section 4 deals with the occurrence of condenser leaks; their impact on power plant operation and equipment; methods for detection, and location, and repair of condenser leaks; condenser tube cleaning methods; air inleakage and condenser maintenance; and station records related to the condenser.

All data related to the performance of various condenser tube materials in different operating environments are presented in Section 5. The calculated failure rates and probable service life of each material in specific environments are given. The section discusses copper alloys, stainless steel alloys, and titanium. There is a concluding discussion of considerations for deciding whether to retube a failing condenser.

Section 6 draws together the significant findings and conclusions that resulted from the study.

Section 7 formulates the proposed programs for further investigation and development that were derived from the work of this study.

Section 2

CONDENSER FUNCTION, DESIGN, AND OPERATION

This Section describes the state of the art for modern, power plant condensers.

The major topics of discussion are:

- Purpose of the condenser in the steam power plant cycle
- Terminology and functions of the major condenser components
- Typical condenser layout arrangements
- Some pertinent features of condenser design

PURPOSE OF THE CONDENSER

The major function of the main condenser is to transfer the heat rejected from the steam cycle to a receiving body of water or to the atmosphere when a cooling tower is employed. The heat transferred is the latent heat of vaporization of the turbine exhaust steam. The rejected heat comprises 60 to 75 percent of the heat generated in the fuel. The total quantity of heat transferred is the "condenser duty" which is usually expressed in Btu/hr.

The condenser also functions as a barrier between the cooling water and the condensate. Modern, high-pressure boilers require high purity feedwater. Less than 1 ppm of total dissolved solids (TDS) is desirable. Cooling waters range in TDS from less than 100 ppm for high quality fresh water used once-through, up to 35,400 ppm for normal seawater used once-through. Any intrusion of cooling water into the condensate is undesirable. The quantity of inleakage that can be tolerated varies, depending primarily on the TDS of the cooling water. Of the constituents that make up the TDS of the cooling water, some such as silica and those contributing to hardness and alkalinity are more significant as pollutants to the feedwater than are others such as sulfate. Inleakage of cooling water can result in scale deposition in the feedwater heaters and boiler, and in increased corrosion throughout the "turbine cycle."

The condenser also serves to remove noncondensable gases from the turbine cycle and, in some cases, to reheat the condensate above the saturation temperature of the condenser.

The function of the condenser in the thermal power cycle is illustrated by Figure 2-1. This figure is a schematic of the steam water cycle for a typical fossil-fueled power plant.

While the turbine cycle for BWR and PWR nuclear power plants is different than that for fossil-fueled power plants, the essential function of the condenser is the same. One difference is that the condenser in a nuclear plant has a considerably higher duty per unit of power generated because of the lower thermodynamic efficiency of current nuclear plants.

CONDENSER CONFIGURATION

A typical configuration of a condenser shell is shown in Figure 2-2. This is an isometric cutaway view of a single pass (of the cooling water) condenser with a divided water box. The illustrated condenser has two bundles of tubes, each with its own air removal section. Cooling water flows in parallel through the two bundles. It is conventional to introduce the exhaust steam from the LP turbine into the top of the condenser as shown at point (12) in Figure 2-2. The cross-sectional area of the steam path expands from the turbine flange, or exhaust connection (12) to the top of the tubing bundle (11). The transition section is the exhaust neck or steam dome. The outer few rows of tubes on the top and sides of the tube bundle are the impingement section (11). The exhaust steam flows throughout the tube bundle condensing section (16) via open lanes in the tube layout pattern. The noncondensable gases are swept along to the air removal section (8) whence they are withdrawn by vacuum pumps or steam jet ejectors. The condenser tubes are affixed by rolling or welding to the tubesheets (9), and supported along their length by support sheets (19). Other waste steam enters the condenser at (3), which is the feed pump drive turbine exhaust, and at (15) which shows some of the many drain and dump connections. Condensate falls to the hotwell (10) and is withdrawn via the condensate outlet (20) by the condensate pumps. The cooling water enters at connection (7) and is distributed across the tubesheet by the "cold end" water box (6). Noncondensable gas accumulating in the water box is removed via connection (4). The

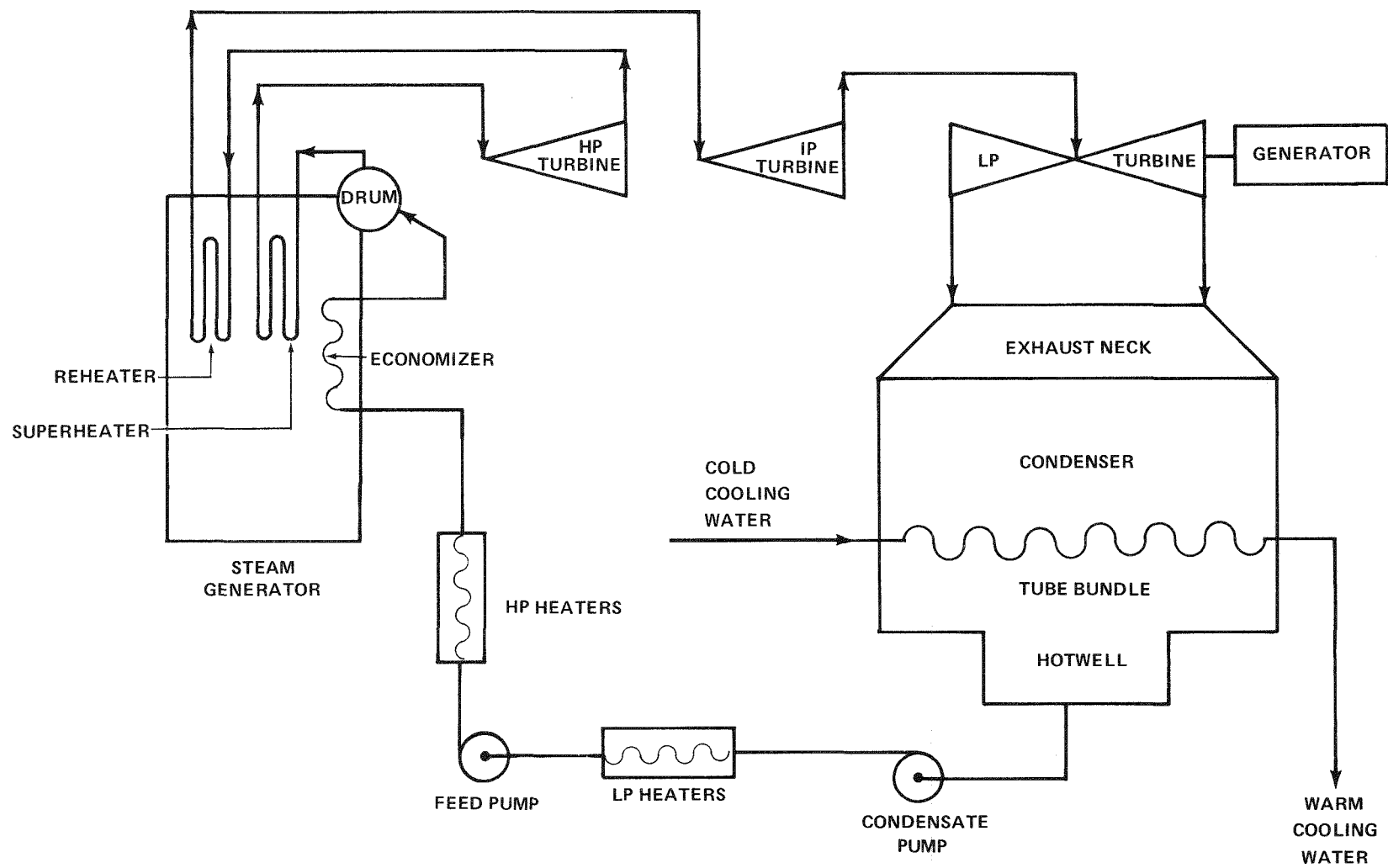
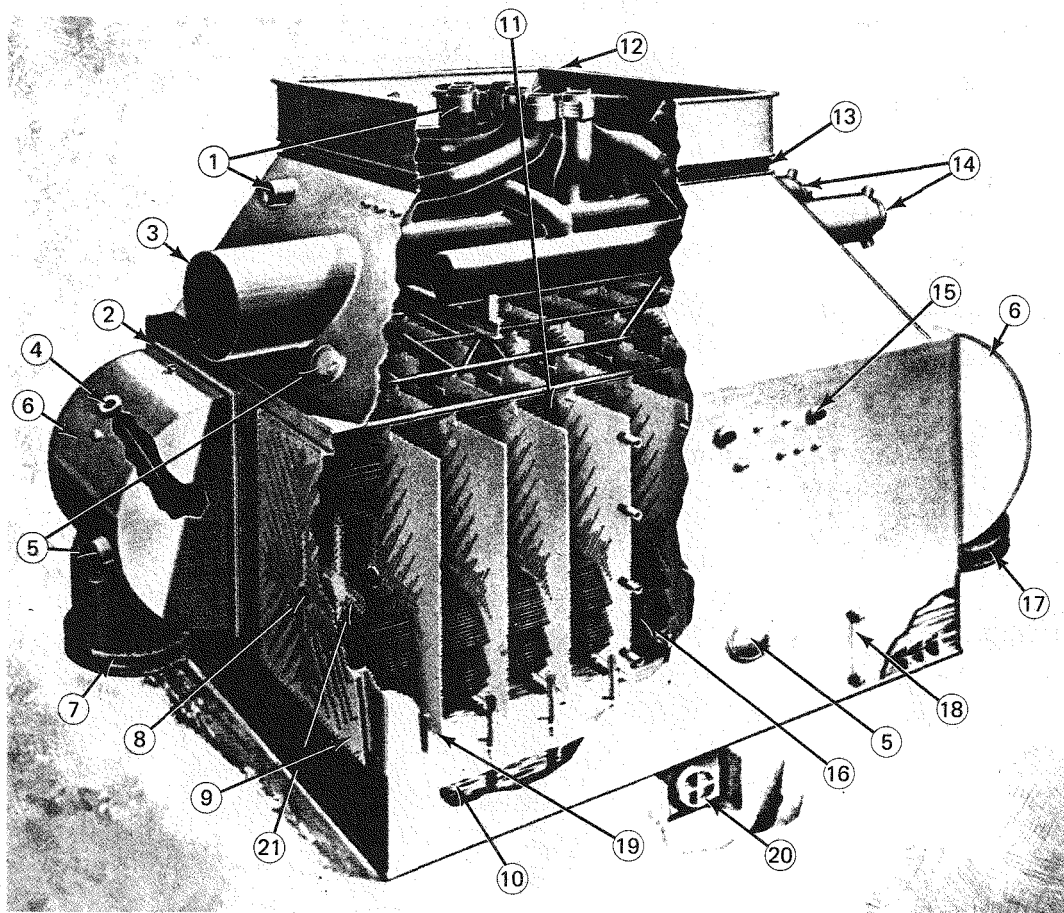


Figure 2-1. Steam Water Cycle



- | | |
|--|---|
| 1. EXTRACTION CONNECTION TO EXTERNAL HEATER | 11. TUBE BUNDLE (IMPINGEMENT) |
| 2. DIAPHRAGM CONNECTION BETWEEN TUBE SHEET AND SHELL | 12. TURBINE EXHAUST HOOD CONNECTION |
| 3. FEED PUMP TURBINE DRIVE EXHAUST | 13. EXPANSION JOINT TO TURBINE EXHAUST HOOD |
| 4. NONCONDENSIBLE REMOVAL CONNECTION | 14. F.W. HEATERS IN CONDENSER STEAM DOME |
| 5. MANHOLE | 15. DUMPS AND DRAINS |
| 6. WATER BOX | 16. TUBE BUNDLE (CONDENSING) |
| 7. COOLING WATER CONNECTION (IN) | 17. COOLING WATER CONNECTION (OUT) |
| 8. TUBE BUNDLE (NONCONDENSIBLE REMOVAL SECTION) | 18. HOT WELL LEVEL |
| 9. TUBE SHEET | 19. TUBE-SUPPORT SHEETS |
| 10. HOT WELL | 20. CONDENSATE PUMP CONNECTION |
| | 21. COLD END BAFFLE IN NONCONDENSABLE SECTION |

Figure 2-2. Single Pass Surface Condenser
Source: Westinghouse

cooling water flows inside the tubes to the "warm end" water box and exits at connection (17). Access to the interior of the water boxes and to the steam space of the condenser is provided by appropriate manholes (5). Differential thermal expansion of the components is accommodated by the tubesheet-to-shell diaphragm (2) and turbine exhaust hood expansion joint (13). Some of the low pressure feedwater heaters are often located in the condenser neck (14).

Condenser Layout Arrangement

Various condenser layout arrangements are made to accommodate numerous factors in the overall power plant design. Some of these considerations are the efficient layout of the turbine floor area, the lowest overall evaluated power generation cost for the plant, etc. Throughout this report, the following generally accepted terminology is used. Each generating unit has only one condenser. This condenser may consist of one to three separate shells. Each shell may contain from one to four tube bundles. The cooling water flow may be single pass, i.e., parallel flow through all bundles, or multipass, i.e., series flow through two or more bundles located in the same shell. The pressure in steam space may be the same in all shells, i.e., single pressure (usually accompanied by single-pass cooling water flow), or the steam side pressure may be slightly different in each shell, i.e., multipressure (usually accompanied by single-pass cooling water flow in series through the shells).

Examples of various condenser layout arrangements are illustrated in Figures 2-3 through 2-7. The condensers shown in Figures 2-3 and 2-4 are transverse arrangements in which the condenser tubes are perpendicular to the turbine shaft:

- Figure 2-3 shows a two-shell, single-pressure, single-pass condenser with four tube bundles.
- Figure 2-4 shows a three-shell, single-pressure, single-pass condenser with six tube bundles. Separate small condensers are provided for the exhaust steam from the auxiliary turbines which drive the feedwater pumps.

Figures 2-5 through 2-7 show longitudinal condenser layouts wherein the condenser tubes are parallel to the turbine shaft:

- Figure 2-5 shows a single shell, divided by intermediate tube sheets to form a three-pressure condenser with a single-pass, series flow cooling water path. There are two parallel tube bundles within each pressure zone. This results in very long condenser tubes.

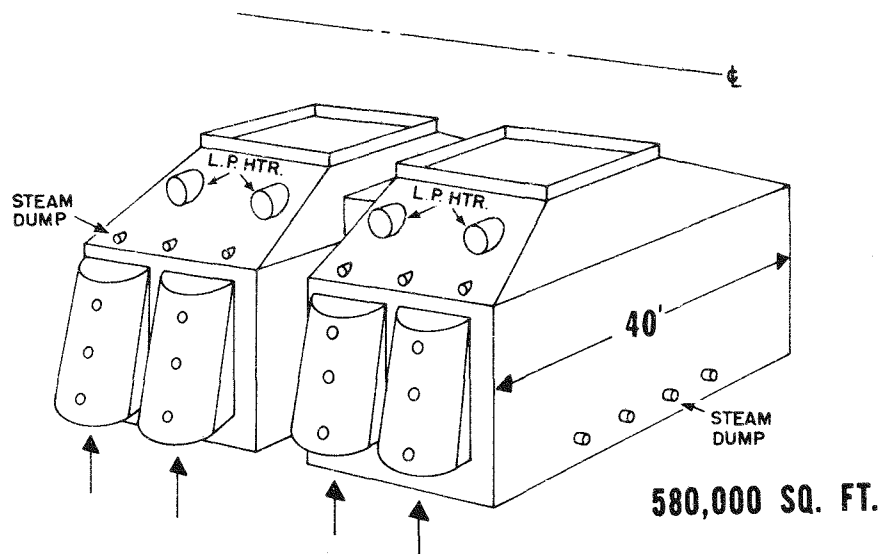


Figure 2-3. Single Pressure, Dual-Shell
Condenser Design

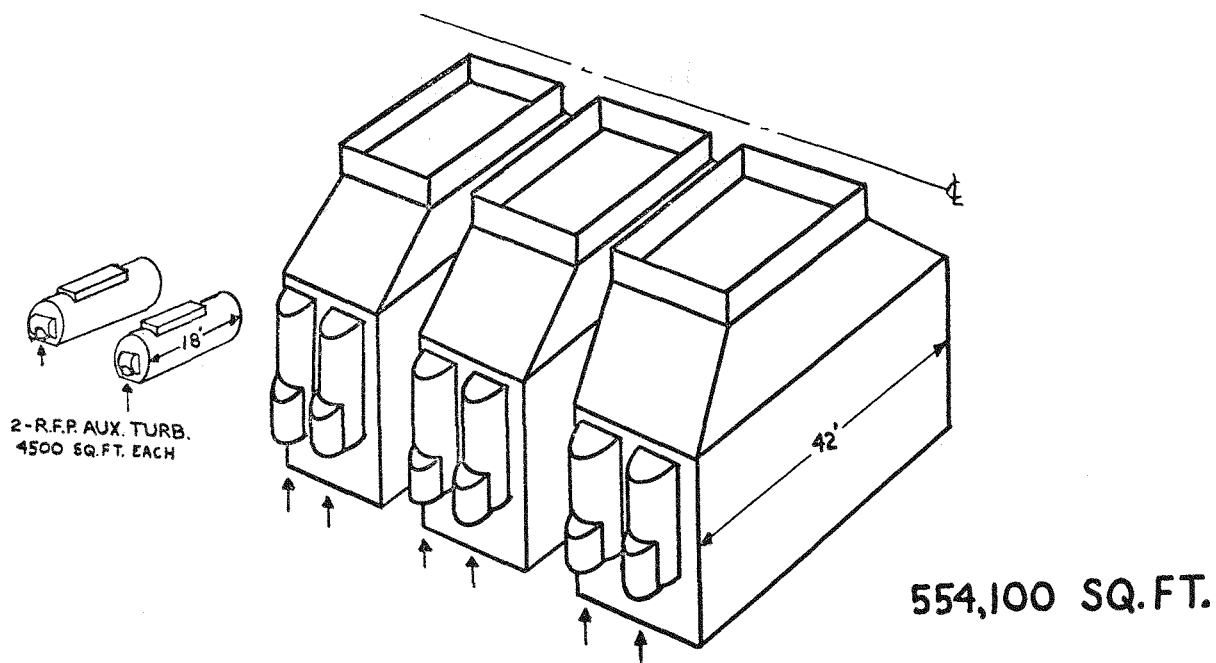


Figure 2-4. Single Pressure, Three-Shell
Condenser Design

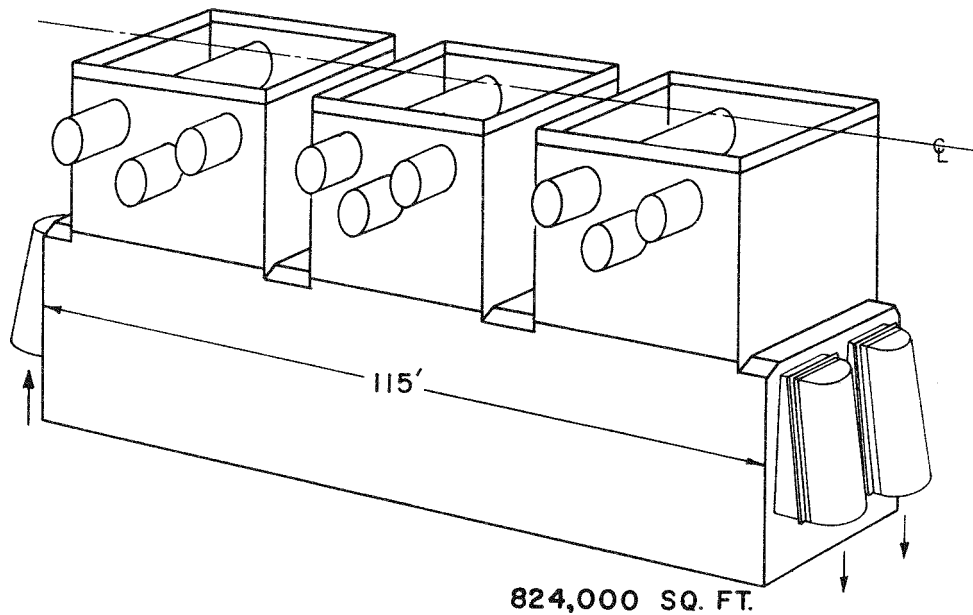


Figure 2-5. Triple-Pressure Condenser with Long Tube Bundles

- Figure 2-6 shows a single-shell, three-pressure condenser similar to that shown in Figure 2-5. An intermediate waterbox is provided in the center to reduce the length of the condenser tubes.
- Figure 2-7 shows a single-shell, single-pressure condenser with three exhaust compartments. The central cooling water inlet boxes provide for single-pass flow through the four parallel tube bundles.

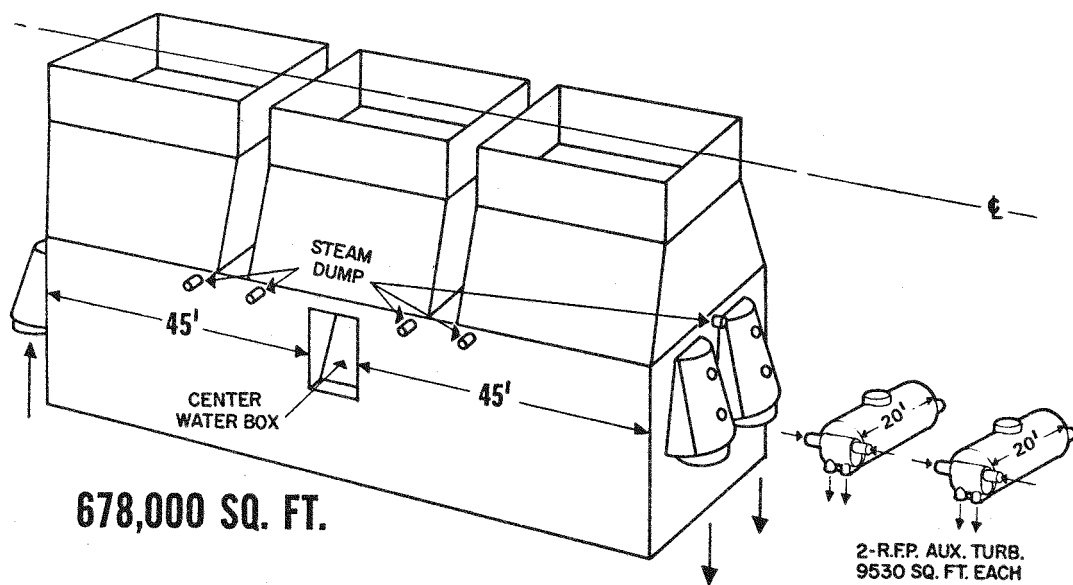


Figure 2-6. Triple-Pressure Condenser

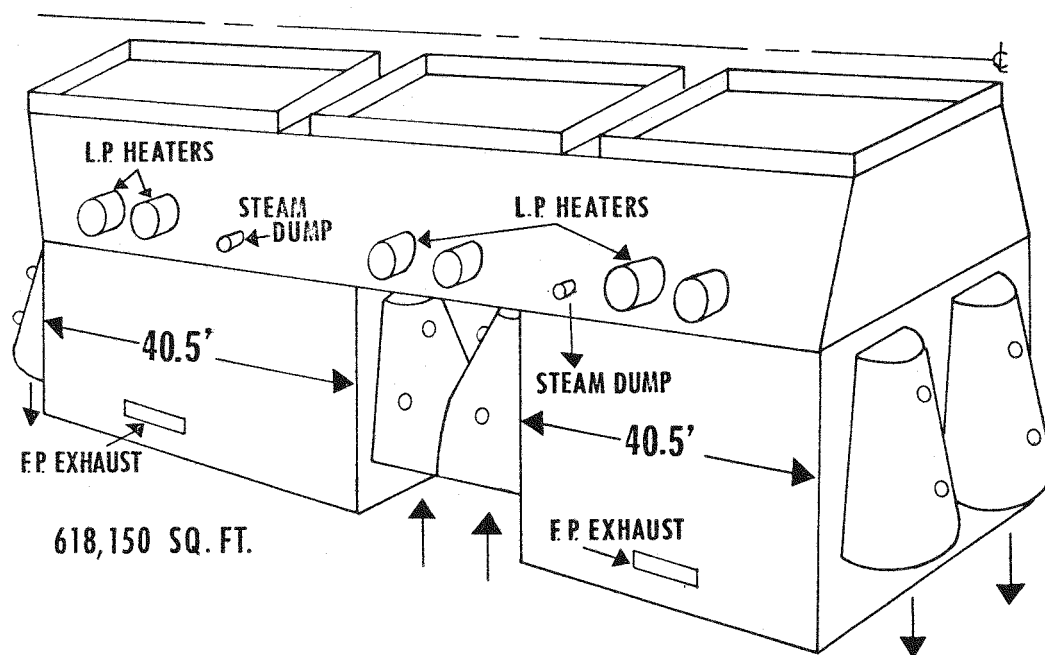


Figure 2-7. Single-Pressure Condenser with Central Cold Water Entrance

CONDENSER DESIGN CONSIDERATIONS

The thermodynamic and structural design of large, modern power plant condensers is a complex undertaking. A rigorous discussion is outside the scope of this report. However, some of the principles of condenser design will be discussed in a simplified approach which will be adequate for the context of this report.

General

The essentials of the heat transfer relationships in condenser design can be expressed by simplified, basic equations.

The total surface area of exposed tubing, S , required in the condenser is:

$$S = \frac{\text{Duty}}{\theta_m \cdot U}$$

where,

S = surface area, square feet

U = heat transfer rate Btu per square foot of surface per
°F of log mean temperature difference

θ_m = °F log mean temperature difference

and,

$$\theta_m = \frac{T_o - T_1}{\ln \frac{T_s - T_1}{T_s - T_o}}$$

where,

T_o = cooling water outlet temperature, °F

T_1 = cooling water inlet temperature, °F

T_s = temperature °F of saturated steam at the
absolute pressure of the condenser

and,

$$U = F_1 \cdot F_2 \cdot F_3 \cdot C \cdot \sqrt{V}$$

where,

F_1 = cooling water temperature factor

F_2 = tube material and wall thickness factor

F_3 = tube cleanliness factor

V = average water velocity in tube, ft/sec

C = condenser tube heat transfer constant

Values for U when $F_1 \times F_2 \times F_3 = 1.0$ are shown in Figure 2-8 for various tube diameters (C values) and water velocities. These values are for new, clean, bright, and oxide-free tubes. The value for F_1 , the factor for inlet water temperature is obtained from Figure 2-9. The value for F_2 , the factor for tube

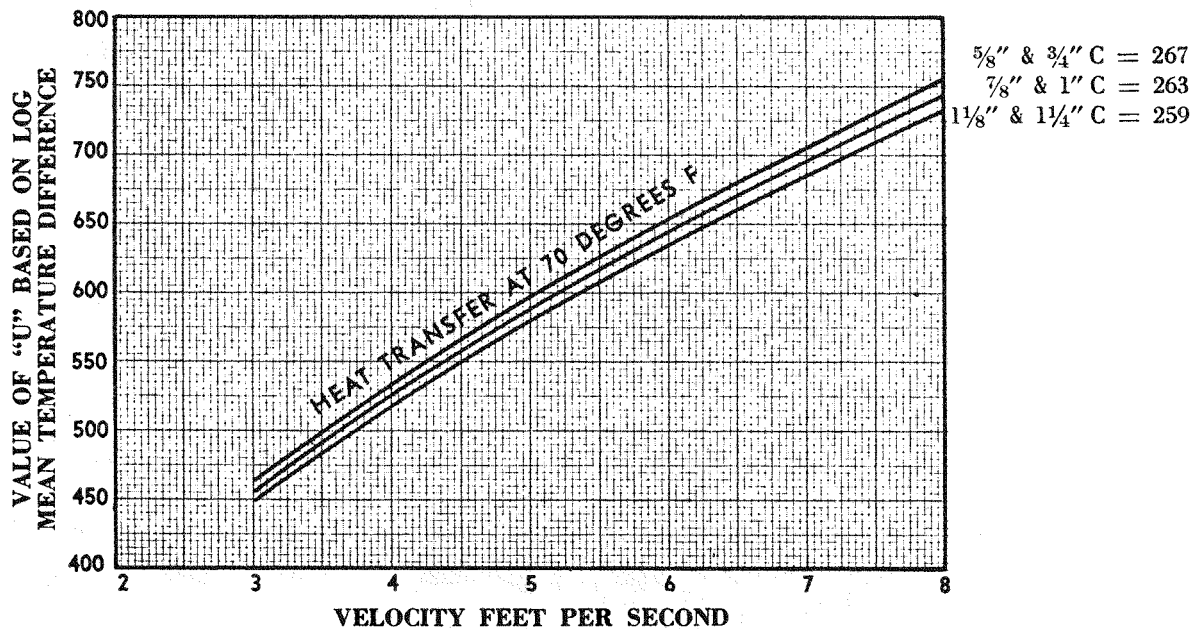


Figure 2-8. Heat Transfer Rate When $F_1 \times F_2 \times F_3$ is 1.0

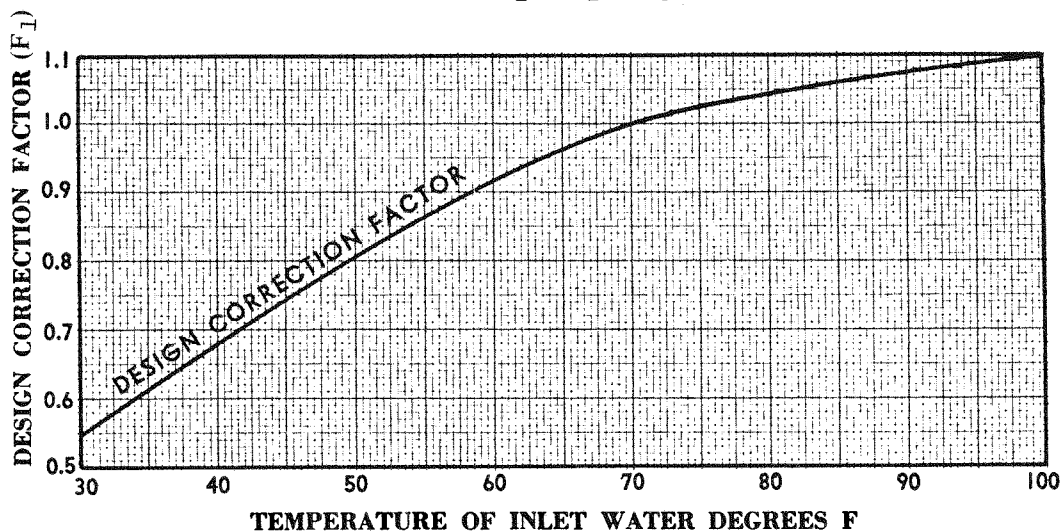


Figure 2-9. Correction to "U" for Cooling Water Inlet Temperature

Source: HEI, Standards for Steam Surface Condensers, Sixth Edition.

material and wall thickness is obtained from Table 2-1. The value of F_3 is the design cleanliness factor assumed and it is a proportion of the performance of new, clean, and bright tubes. Conventionally, F_3 is taken as 0.85 for copper alloy tubes and as 0.90 for stainless alloy or titanium tubes. The cleanliness factor is increased by 0.05 when a continuous tube cleaning device (e.g., Amer-tap) is used.

The required cooling water flow, Q is approximately:

$$Q = \frac{\text{Duty}}{500(T_o - T_1)}$$

Q is gpm
Duty is Btu/hr

The optimization of the condenser design parameters is a complex process. To select the best combination of surface area; tube diameter, gauge and length; temperature rise; etc. involves many economic and technical tradeoffs. Condenser optimization is usually done with the assistance of an appropriate computer program. In the selection of the tube material consideration must be given first to its serviceability in the particular environment, and then to its heat transfer and mechanical properties. The ratio of surface area to turbine rating varied from 0.3 sq ft/KW to 1.05 sq ft/KW at the 30 stations surveyed by this study.

Steam-Side Considerations

Steam Velocity. The expanded steam exhausts from the low pressure turbine at high velocity and with a considerable moisture content. The exhaust loading varies from 7,500 lb/hr/sq ft of area at the exhaust connection to 15,000 lb/hr/sq ft. When the absolute pressure of the condenser is low (due to low cooling water temperature) the steam exhausts from the turbine at or near sonic velocities. The distribution of the steam flow is not uniform over the exhaust connection area. There is a concentration of flow (high velocity region) adjacent to the bearing end of the turbine. This is illustrated in Figure 2-10 which is a plot of a free flow air test pattern for a turbine of current design. A transition section (exhaust neck or steam dome) is needed to reduce its velocity. The tubesheet configuration must provide proper lanes to distribute the steam to within the tube bundle, and to transport the noncondensable gases to their collector. A typical tubesheet configuration is shown in Figure 2-11.

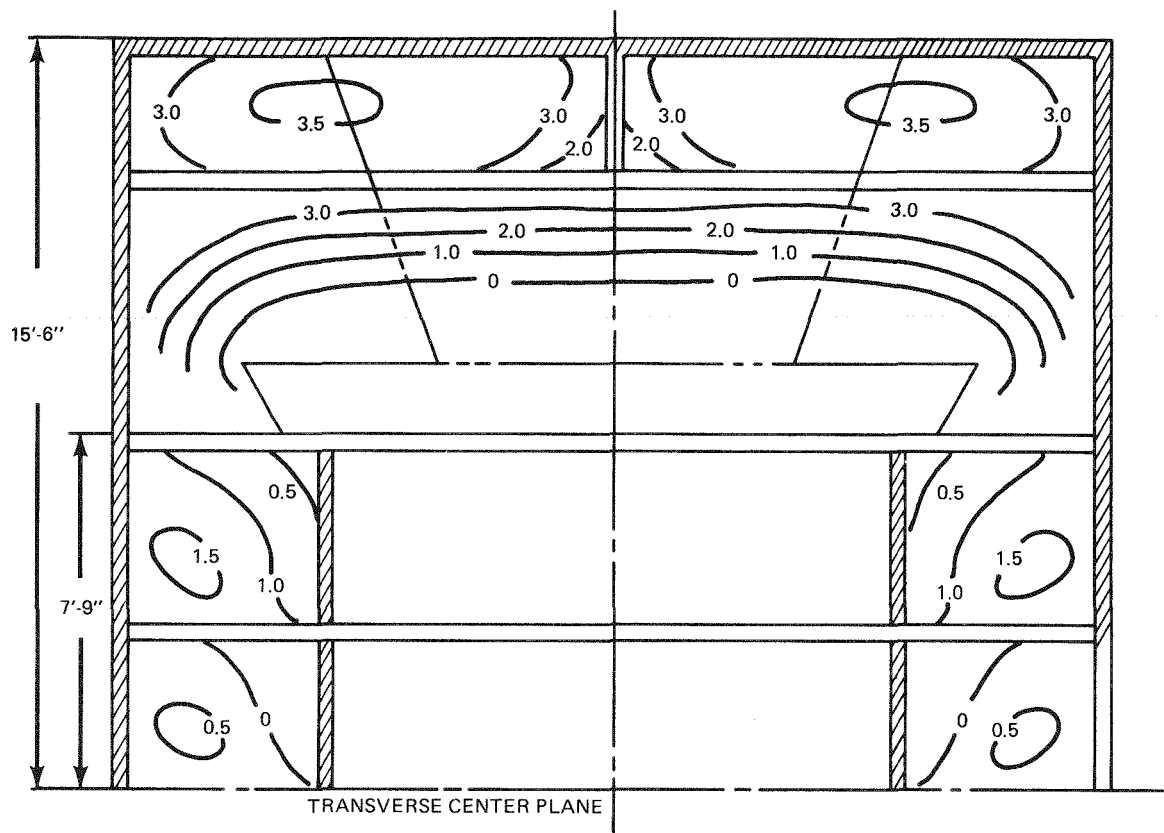
Removal of Noncondensable Gases. The noncondensable gases consist primarily of air which is drawn into the evacuated condenser and its subatmospheric appurtenances through leaks at packing glands, welds, threaded joints,

Table 2-1*

DESIGN CORRECTION FACTORS FOR CONDENSER TUBING MATERIALS (F_2)

TUBE MATERIALS	TUBE WALL GAUGE - BWG						
	24	22	20	18	16	14	12
Admiralty Metal	1.06	1.04	1.02	1.00	0.96	0.92	0.87
Arsenical Copper	1.06	1.04	1.02	1.00	0.96	0.92	0.87
Aluminum	1.06	1.04	1.02	1.00	0.96	0.92	0.87
Aluminum Brass	1.03	1.02	1.00	0.97	0.94	0.90	0.84
Aluminum Bronze	1.03	1.02	1.00	0.97	0.94	0.90	0.84
Muntz Metal	1.03	1.02	1.00	0.97	0.94	0.90	0.84
90-10 Cu-Ni	0.99	0.97	0.94	0.90	0.85	0.80	0.74
70-30 Cu-Ni	0.93	0.90	0.87	0.82	0.77	0.71	0.64
Cold-Rolled Low Carbon Steel	1.00	0.98	0.95	0.91	0.86	0.80	0.74
Stainless Steels							
Type 410/430	0.88	0.85	0.82	0.76	0.70	0.65	0.59
Type 304/316	0.83	0.79	0.75	0.69	0.63	0.56	0.49
Type 329	0.78	0.76	0.74	0.69	0.65	0.60	0.54
Titanium (tentative)	0.85	0.81	0.77	0.71	----	----	----

*Source: HEI, Standards for Steam Surface Condensers, Sixth Edition.



DOUBLE FLOW – DOWN DISCHARGE – 38" OR 43" L58 – HERZOG HOODS
 BASED ON AIR TEST TRAVERSES FROM SET 231
 REPLACES 327 HA 481

NUMBERS ON CURVES DENOTE THE RATIO OF LOCAL FLOW
 PER UNIT AREA TO AVERAGE FLOW PER UNIT AREA

Figure 2-10. Flow Distribution over Area of the
 Exhaust Connection. Source: General Electric

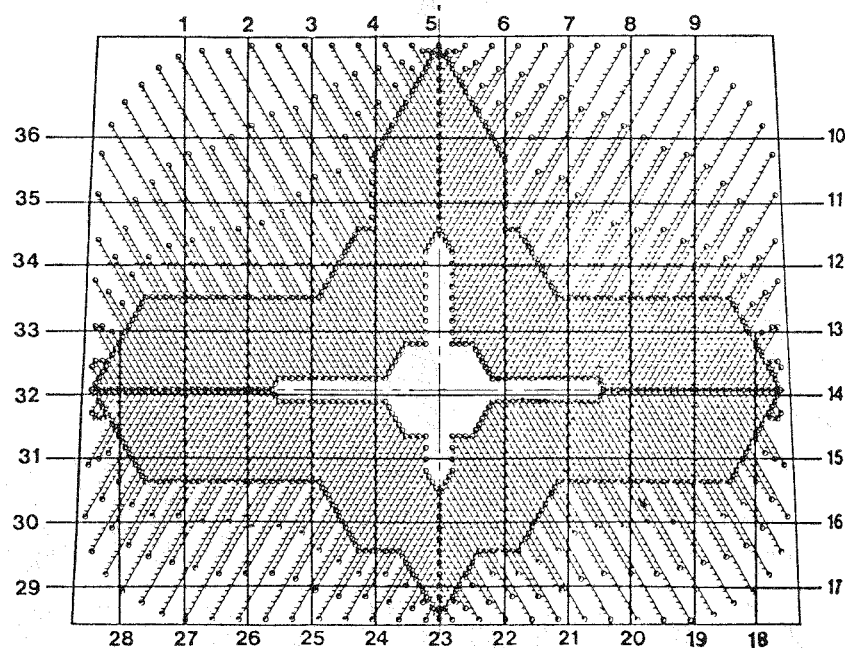
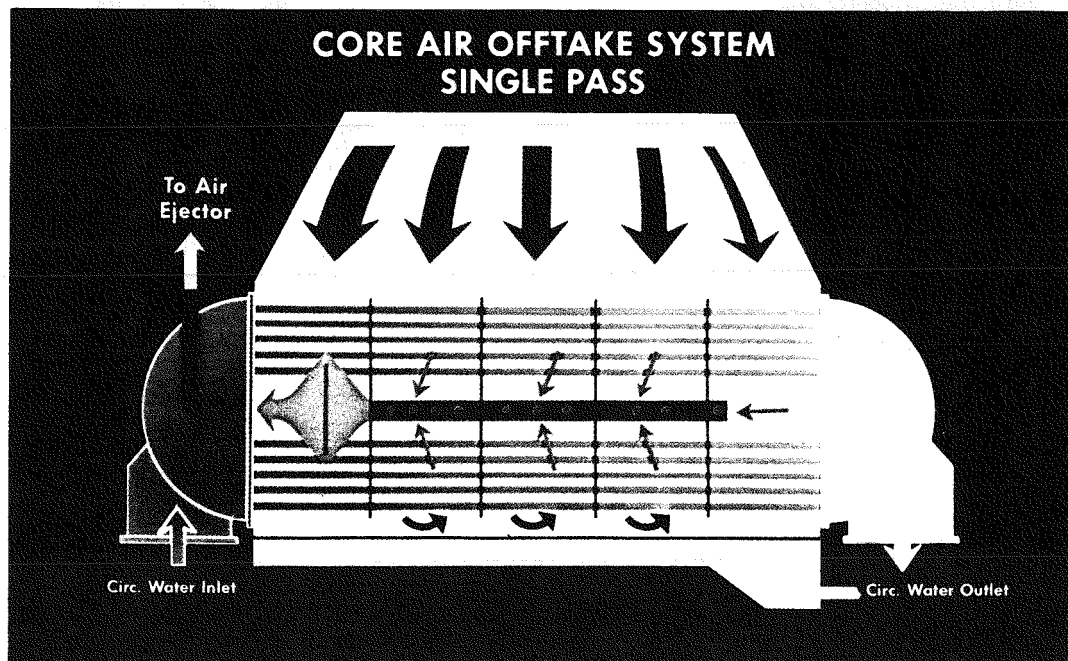


Figure 2-11. Tubesheet Configuration Designed for Steam Entry All Around the Tube Bundle

instrument connections, etc. In the steam from boiling water reactors there is a significant concentration of hydrogen and oxygen due to the radiolytic decomposition of water within the nuclear fuel core. In fossil and PWR plants which employ volatile feedwater treatment additives the noncondensibles include a small volume of ammonia and the decomposition products of hydrazine and, possibly, of other volatile amines. The noncondensable gases must be promptly evacuated from the condenser to prevent their rendering a part of the heat transfer surface ineffective due to air binding.

One method for removal of the noncondensibles is shown in Figure 2-12 as applied to a single-pass condenser, and again in Figure 2-13 as applied to a two-pass condenser. This method is also illustrated in Figure 2-2. The core collector draws the noncondensibles, together with some water vapor, from between each pair of tube support plates and transports the mixture to the cold end of the condenser. Here the mixture is passed over the coldest tubes, to reduce the water vapor concentration to the minimum possible, and then withdrawn by the air removal system. The noncondensable core collector is not shrouded. The condensate formed on the tubes above flows down through the air removal zone. Any ammonia concentrated in the air removal zone can be absorbed by this condensate up to equilibrium limitations. The quantity of ammonia removed with the noncondensable gases is at the resulting equilibrium minimum.

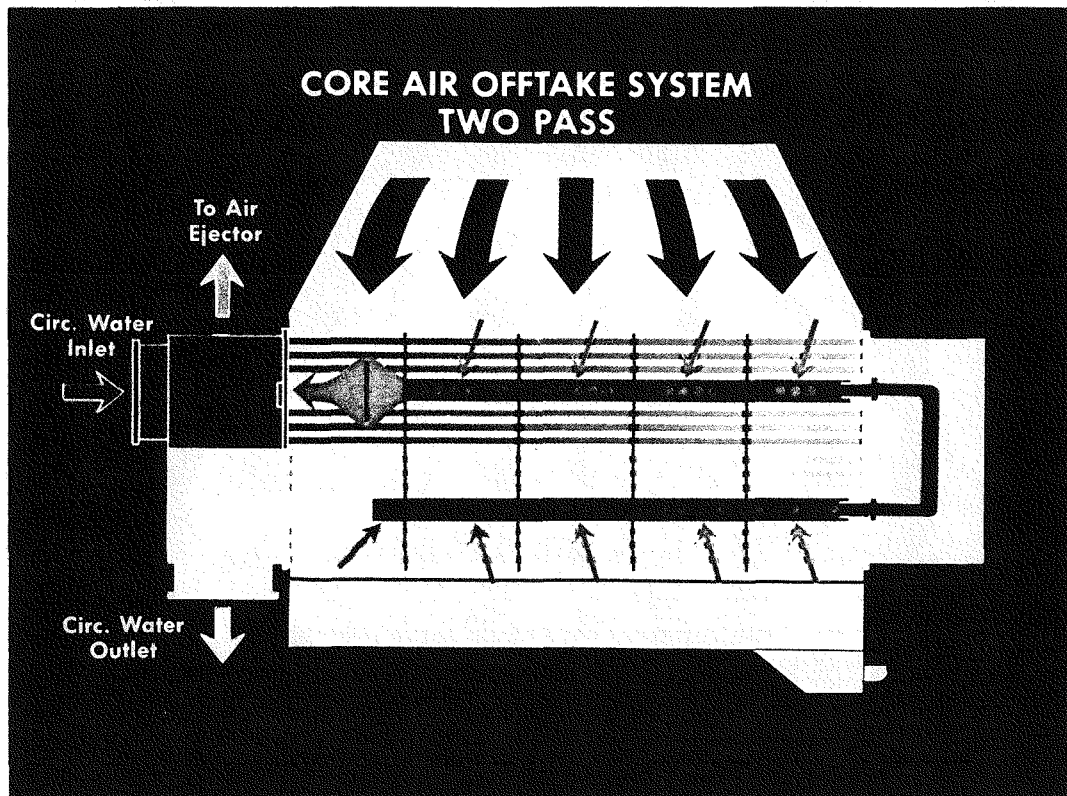


Core Air-Offtake

Features

- 1) Non-condensables are removed from the center of tube banks providing -
Short steam flow paths
Low pressure losses
- 2) Core air-offtake pipes have a varying number of orifices in each bay to insure that each bay can capably handle the volume of noncondensables associated with the condensing action, thus balancing the venting properly along their entire lengths.
- 3) Non-condensables are removed by first passing them over a few rows of tubes to subcool the air and vapor mixture adequately - then transporting them out of the condenser through pipes located in the water boxes, and thence to the air-removal system.
- 4) Each bundle is individually vented to assure proper removal of non-condensables.

Figure 2-12. Noncondensible Gas Collection in Single-Pass Rectangular Surface Condenser. Source: Westinghouse



Core Air-Offtake

Features

- 1) Non-condensables are removed from the center of tube banks providing –
Short steam flow paths
Low pressure losses
- 2) Core air-offtake pipes have a varying number of orifices in each bay to insure that each bay can capably handle the volume of noncondensables associated with the condensing action, thus balancing the venting properly along their entire lengths.
- 3) Non-condensables are removed by first passing them over a few rows of tubes to subcool the air and vapor mixture adequately – then transporting them out of the condenser through pipes located in the water boxes, and thence to the air-removal system.
- 4) Each bundle is individually vented to assure proper removal of non-condensables.

Figure 2-13. Noncondensible Gas Collection in Two-Pass Rectangular Surface Condenser. Source: Westinghouse

Another method for removal of the noncondensibles is shown in Figure 2-14. In this design, the air removal section is shrouded. The placement of the shrouded air removal section within the tube bundle is shown in Figure 2-15. The mixture of noncondensibles and water vapor collected between tube support plates is cascaded to the cold end of the condenser. The water vapor content is minimized by drawing the mixture over the coldest tubes just prior to its withdrawal by the air removal system. The shroud prevents "washing" of the collected noncondensibles by the condensate from above. Soluble gases such as ammonia are removed from the condenser more effectively as compared to the open air removal section described above.

The design capacity of the air removal (venting) system is given in the Heat Exchange Institute "Standards for Steam Surface Condensers," 6th Edition. The capacity provided is a function of the number of turbine exhaust openings, the steam flow per exhaust opening and the concentration of dissolved oxygen desired in the effluent condensate. Either steam jet ejectors or vacuum pumps are used to evacuate the noncondensable gases from the condenser.

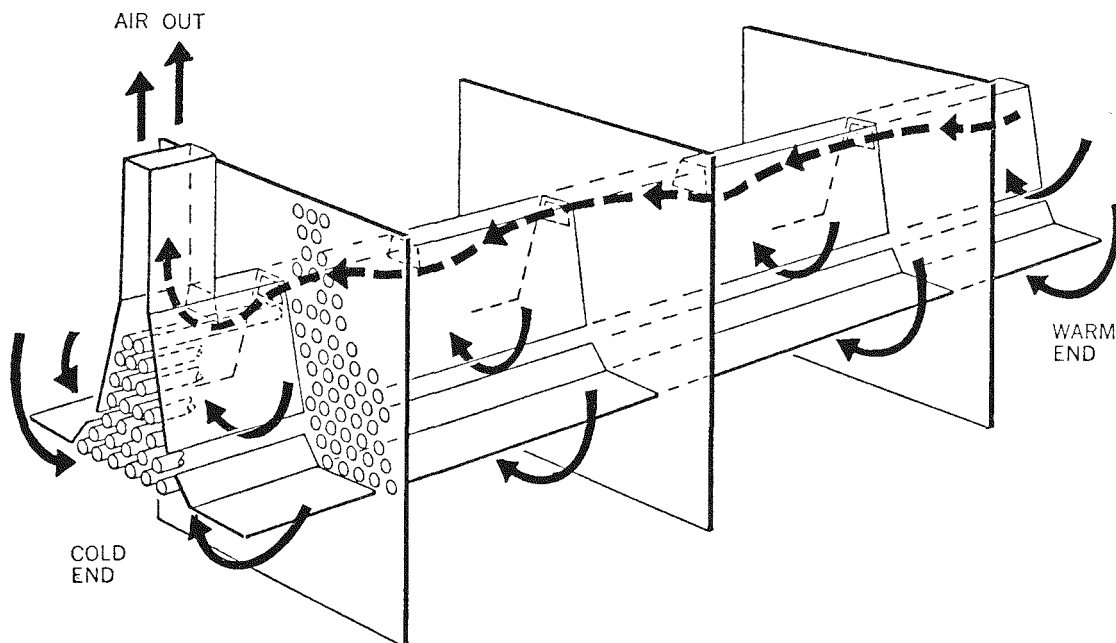


Figure 2-14. Shrouded Air Removal Section for Cascaded Removal of Noncondensibles.
Source: Ingersoll-Rand

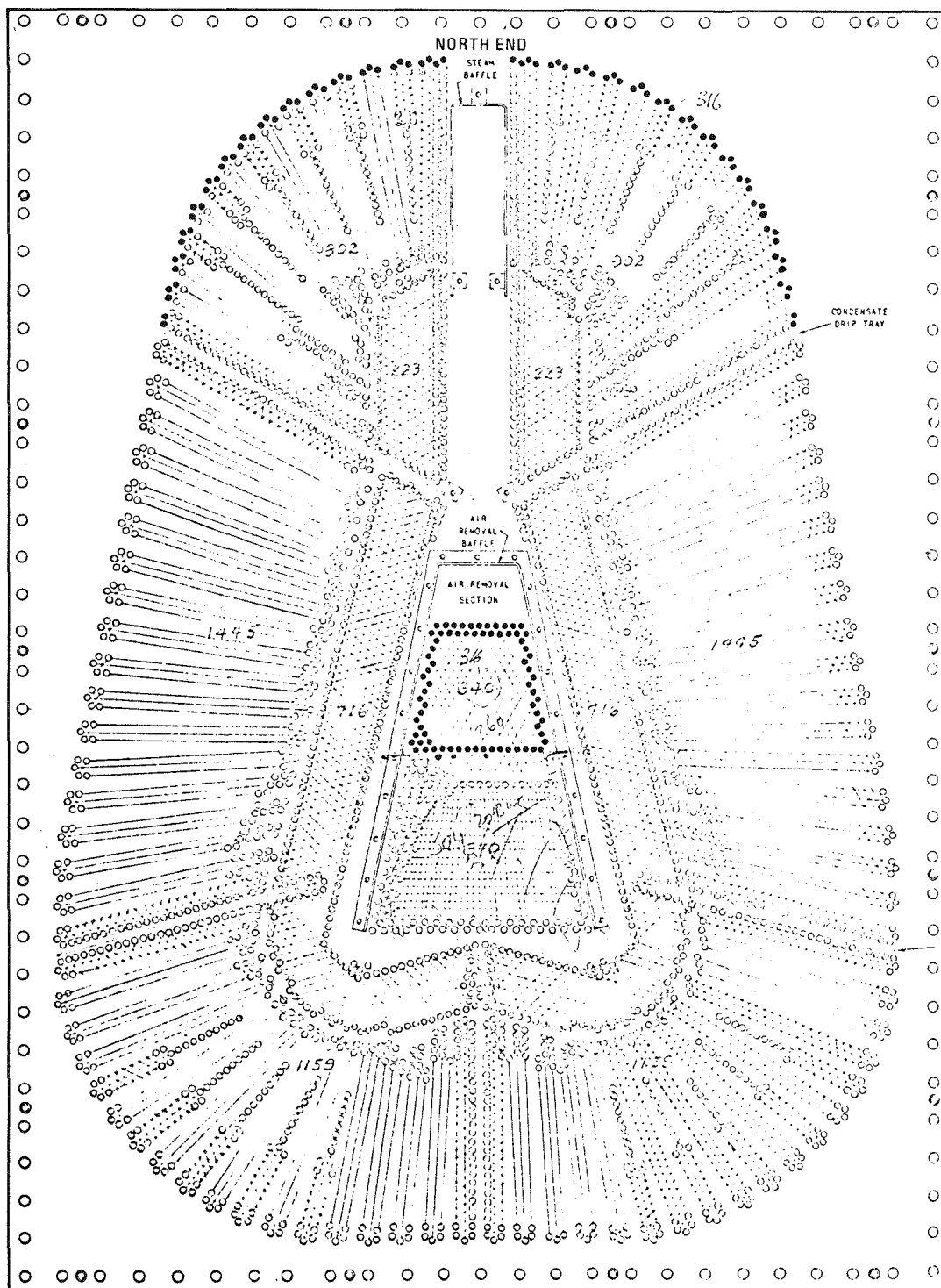


Figure 2-15. Location of Shrouded Air Removal Section in Tube Bundle

Water-Side Considerations

Cooling Mode. Whether the cooling mode is open cycle or closed cycle has a very significant impact on many water-side design considerations. Open cycle is once-through cooling with either fresh or salt water. Closed cycle is any concentrating circulating water system and includes cooling towers, cooling ponds, and spray ponds or canals which recycle the cooling water. The cooling mode directly or indirectly affects the cooling water inlet temperature, the cooling water temperature range, the exposed condensing surface area, the waterbox pressure, the stress on the tube-to-tubesheet joint, related structural and mechanical design requirements, etc. These impacts are discussed in more detail under the individual headings which follow.

In addition to the above impacts on condenser design, the cooling mode can also affect the efficiency of the generating plant. Plants with open cooling systems can take advantage of the generally lower cooling water temperature and the resulting lower absolute pressure in the condenser to justify economically a turbine with a larger back end. This usually results in a lower heat rate for the plant. In plants with closed cooling water systems, the turbine must exhaust against a higher average condenser backpressure. This may result in the choice of a smaller back end and the plant heat rate will be higher.

As brought out in Section 3, a substantial majority of the power plants now in operation in the United States use the open cooling mode. However, under the present regulations for effluents from steam electric power generating stations (40 CFR 423), all power plants which were first placed in service after January 1, 1974 (after January 1, 1970 for plants larger than 500 MWe) in effect must employ a closed cooling water system unless an exception is granted within the provisions of 40 CFR 122 (Thermal Discharges).

Temperature Range. The cooling water temperature range, T_R , is defined as:

$$T_R = T_O - T_I$$

Both the inlet cooling water temperature (T_I) and the temperature range (T_R) influence strongly the condenser's design and performance. As shown earlier in this Section, the required exposed condensing surface area is inversely proportional to the log mean temperature difference which, in turn, is a function of the temperature range. Also, the quantity of circulating water required is directly proportional to T_R .

As a practical matter, both the average inlet temperature and average temperature range are lower for open systems than for closed systems. The temperature of natural surface water bodies is usually well below the wet bulb temperature of the ambient air over a considerable portion of the year. Economic design considerations result in an "approach" for closed evaporative cooling systems in the range of 8 to 15°F. The approach is the difference between the temperature of the cooled water (inlet water to the condenser) and the ambient air wet bulb temperature.

In the existing open cooling systems, the temperature range (T_R) generally is from 15 to 20°F. This range is commonly limited by the impact of the thermal discharges on the receiving water. In closed cooling water systems, the temperature range is usually from 30 to 40°F. The temperature range for closed cooling systems is generally determined by economic conditions.

Tube Velocity. As shown above the heat transfer rate for a given condenser tube is proportional to the square root of the average cooling water velocity. From just this consideration, then, high velocities are desirable in order to reduce the required condensing surface area. On the other hand, higher velocities increase the friction loss and therefore the pumping energy. Also, higher velocities can cause severe erosion of the condenser tube material. The selected velocity must balance these considerations, along with many others, in the optimization of the condenser design. In practice, a velocity of 7 ft/sec is used almost exclusively with copper alloy tubes. With stainless steel tubes, a velocity of 7 to 8 ft/sec is usual. At every one of the 30 stations surveyed in the field the water velocity was a nominal 7 ft/sec despite variations in tube material and circulating water composition.

Waterboxes. The principal function of the waterbox is to evenly distribute the incoming water across the tubesheet. Ideally, the velocity of approach would be constant at all points. In nearly all condensers the waterbox acts as a 90-degree elbow to turn the incoming water into the tubesheet. When waterbox pressure is only slightly above atmospheric (or even below atmospheric in some syphon leg circulating water systems), previously dissolved air is released. The released air must be removed from the waterbox to prevent air binding of the condenser tubes on the water side. Air release, together with improper inlet water distribution, can induce inlet-end erosion of the condenser tubes. In condensers that have experienced inlet-end erosion, open-end plastic or metal tubes have been inserted 6 to 12 inches into the condenser tube to alleviate the problem.

To combat cavitation, erosion, and corrosion, waterboxes usually have a protective coating, a cathodic protection system, or a corrosion-resistant metal lining. Common protective coatings include epoxies and other plastics, fiberglass, and rubber. Cathodic protection systems may consist of either sacrificial anodes affixed to the waterbox or impressed current systems. The cooling water must have a low electrical resistance for cathodic protection to be economical.

In open cooling systems, the cooling water body is almost always at an elevation below that of the condenser waterboxes. Hence, the pressure in the waterboxes and the condenser tubes seldom exceeds a few psig and can be subatmospheric. In a closed cooling system which uses a cooling tower, the bottom of the cooling tower is commonly at a higher elevation than the waterboxes. Also, the cooling water must be lifted an additional 30 feet or more to the top of the cooling tower fill. There results a waterbox pressure of 30 psig or more depending on the relative elevation of the cooling tower to the condenser and the pump characteristics. Due to the higher pressure in a closed system, a given size of opening in a condenser tube will pass more circulating water into the condensate than would an open system. The increase in inleakage flow varies as the square root of the increase in pressure.

Tube-to-Tubesheet Joints. A tight tube-to-tubesheet joint obviously is mandatory to prevent circulating water inleakage. The tube joint also serves an important structural function. The joint must resist the pull-apart forces which exist when the condenser is hydrotested on the steam side with empty waterboxes to detect joint or tube leaks. The joint must also resist the tension or compression forces that can occur under other conditions. Because of the holes in the tubesheet, the net forces on the waterbox can place tensile or compressive forces on the tubes. The nature and magnitude of net force depends primarily upon the waterbox pressure, the steam space pressure, and the fraction of the tubesheet that is drilled out. Severe tensile or pull-apart forces can exist in an unevacuated condenser with high waterbox pressure, e.g., closed cooling tower circulating water system.

Common tube-to-tubesheet joints are the following:

- Plain rolled joint
- Grooved rolled joint (single or double grooved)
- Welded joint (seal weld or strength weld)

- Grooved rolled joint with overlapping internal grooves that interconnect all tubes
- Packed joint which allows tube expansion when the tubesheet-to-condenser shell joint is rigid
- Double tubesheet joints - the tube is rolled into two closely spaced tubesheets at either end.

Most of these joints are illustrated in Figure 2-16. In existing power plants, the first two types of joints are by far the most common. It is beyond the scope of this report to analyze the technical and economic aspects of the several joining systems.

MAINTENANCE OF TUBE CLEANLINESS

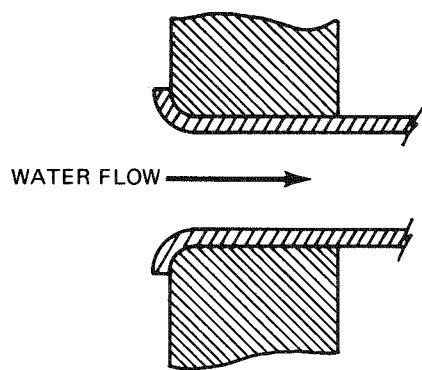
While in service, condenser tubes develop deposits of foulants which reduce the effective heat transfer rate. The foulants may be metallic oxides, mineral scales, or biomasses.

All condenser tube materials, on exposure to circulating water and air, develop an adherent film of oxides of the metals in the alloy. This oxide film protects the base metal against further corrosion and normally does not form to an extent that significantly reduces design heat transfer rate.

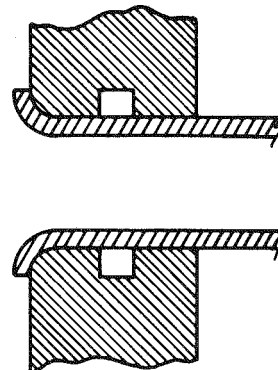
Mineral scales such as calcium carbonate, calcium sulfate, aluminum silicate, etc, are very rare in open cooling systems. In closed cooling systems, such scales can occur when proper circulating water chemistry is not maintained. Mineral scales cause a severe reduction in heat transfer rate and an attendant increase in condenser pressure. When scale does occur, its removal may require mechanical or chemical cleaning.

Biomasses, commonly composed of filamentous algae or slime forming organisms, are the most prevalent foulant, in both open and closed cooling systems.

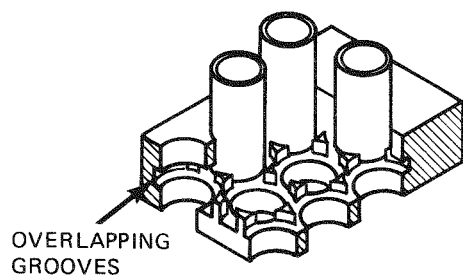
Control of tube fouling is accomplished by application of chemical biocides or by mechanical cleaning. Mechanical cleaning devices are available which can be used with the condenser in service or off-line.



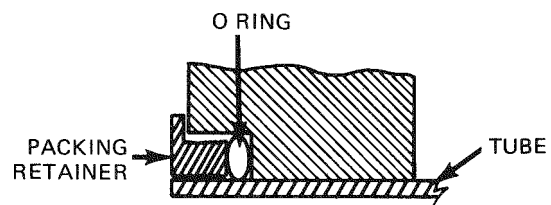
(A) ROLLED JOINT



(B) GROOVED AND ROLLED JOINT



(C) GROOVED AND ROLLED – WITH PRESSURIZED OVERLAPPING GROOVES TO SEAL THE C.W.



(D) PACKED JOINT

Figure 2-16. Typical Tube-to-Tubesheet Joints

Biocides

While a number of suitable biocides are available, chlorine is the unanimous choice at power generating stations. Chlorine is selected because of its biocidal effectiveness, its lower cost, and its availability. Chlorination requirements vary seasonally since bioactivity (especially of photosynthetic algae) is affected by sunlight. Chlorination practices vary within the industry but a typical plant may chlorinate once or twice a day in the winter and three or four times a day in the summer. Chlorine is applied at a rate that will produce a chlorine residual of 0.5 to 1.0 ppm in the water leaving the condenser. Each chlorine application may last 15 to 60 minutes.

Mechanical Cleaning Devices

On-Line. The two available systems for on-line cleaning are the Amertap system and the MAN system.

In the Amertap system, sponge rubber balls are introduced into the inlet water-box. The neutral buoyant density of the balls enables a random distribution of balls over the entire tubesheet. The balls are driven through the tubes by the circulating water. The balls are slightly larger in diameter than the tube ID; hence a cleaning of the tubes results. The balls are retrieved in a catcher device in the outlet circulating water line. After automatic classification to eliminate defective balls, the balls are recycled by a pump to the inlet water-box. Figure 2-17 illustrates the Amertap system.

The MAN system consists of a stiff brush retained in each condenser tube by suitable end-cages. The circulating water piping is arranged to allow periodic reversal of flow. Each flow reversal drives the brush through its respective tube. The MAN system is shown in Figures 2-18 and 2-19.

Off-Line. Over the years, condenser tubes have been cleaned by manual rodding with brushes or plugs. One currently used system for cleaning the tubes consists of inserting a specially designed scraper in the tube and propelling it rapidly through the tube by a hydraulically operated gun.

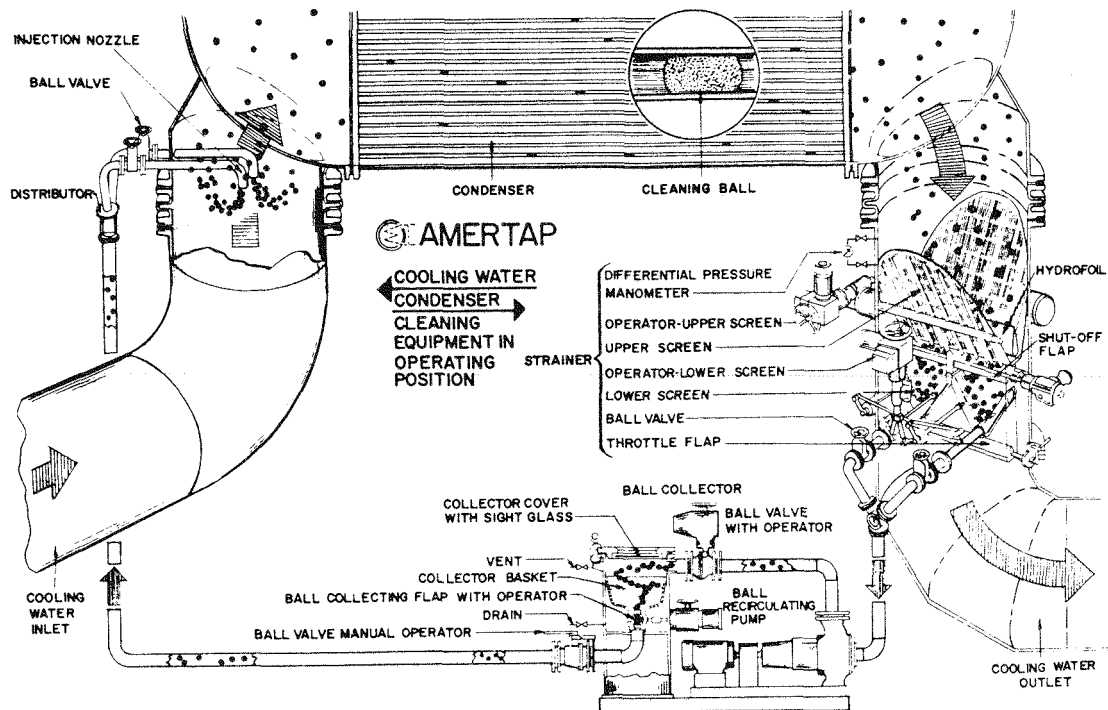


Figure 2-17. Typical Installation, Amertap Condenser Tube Cleaning System

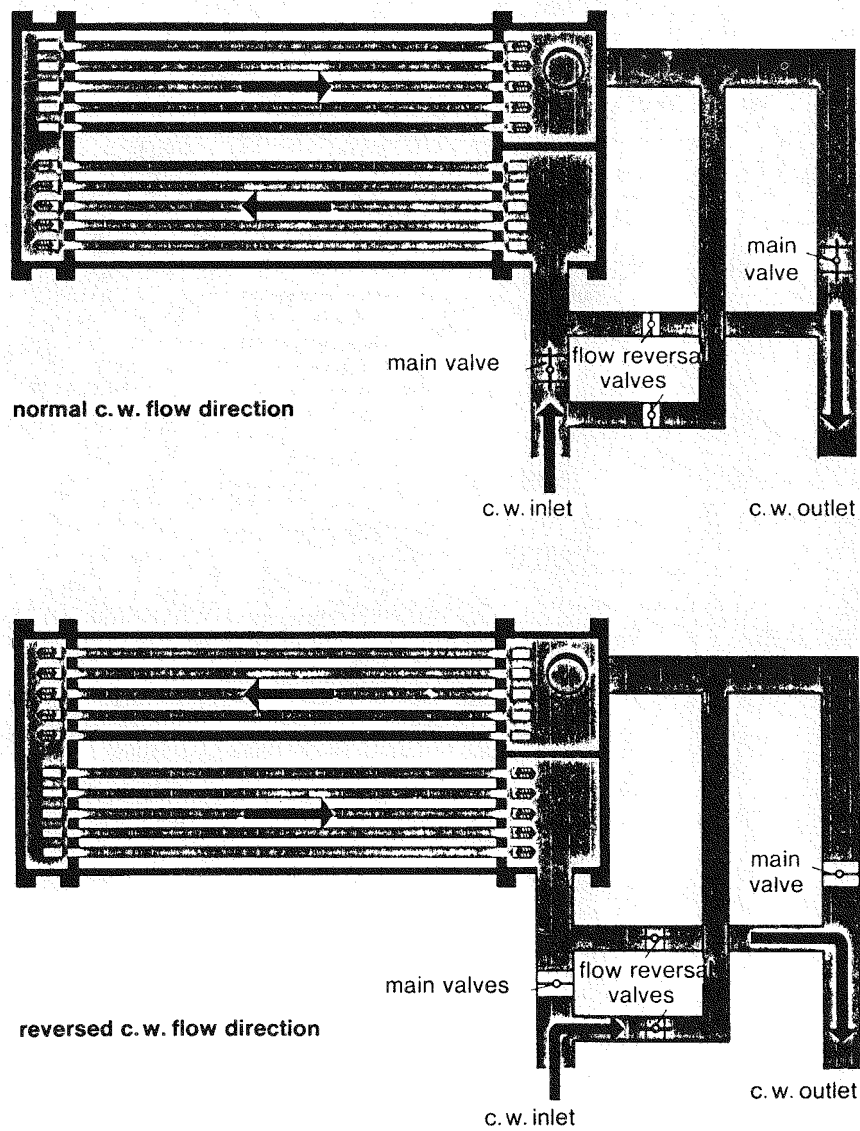


Figure 2-18. MAN System for On-Line Cleaning of Condenser Tubes

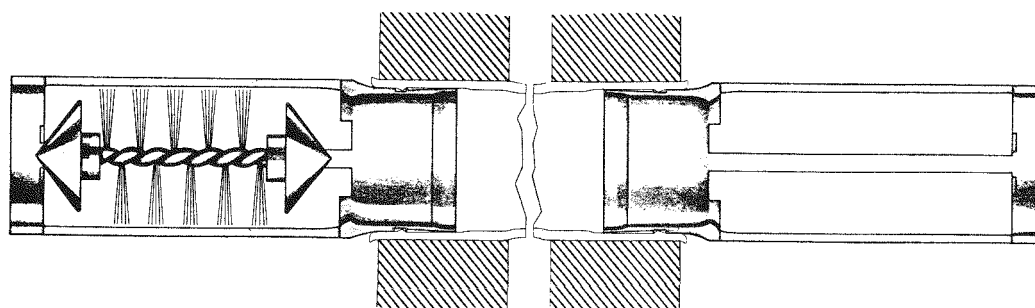
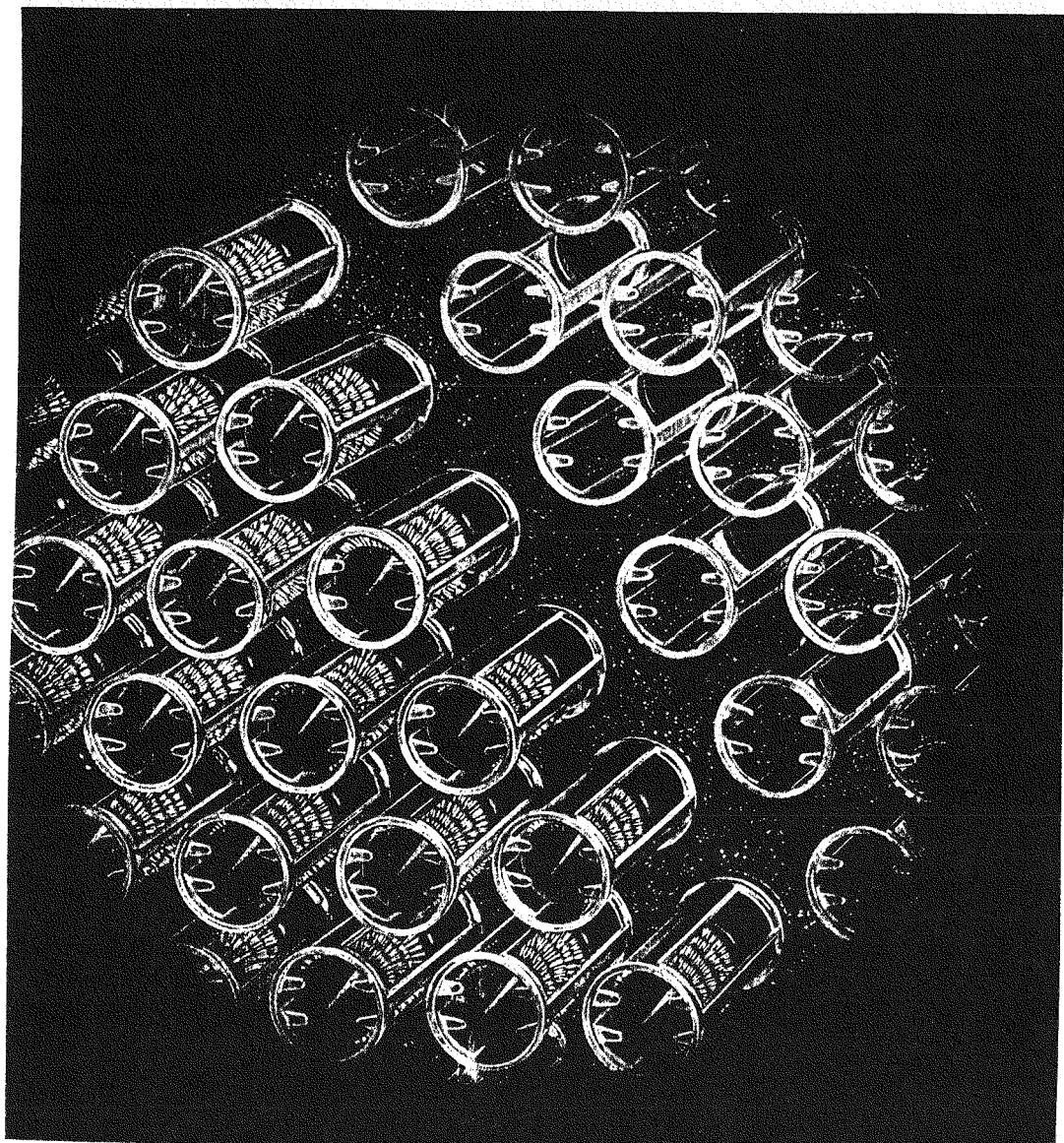


Figure 2-19. MAN On-Line Cleaning System for Condensers and Tubular Heat Exchangers

Section 3

METHODOLOGY OF THE PRESENT STUDY

INTRODUCTION

This section describes the methodology employed to accomplish the major work items, which will be discussed in the following order: 1) Literature Survey; 2) Matrix for Selection of Field Survey Stations and Mail Survey; 3) Field Survey; and 4) Data Management System.

LITERATURE SURVEY

Mechanics

The initial approach to the literature survey was a search conducted by Bechtel central library personnel of the computerized portions of the Engineering Index (Compendex), which contains entries dated from 1970 to the present, and of the National Technical Information Service Index, which dates from 1964. The first step was to determine the number of titles listed under various keywords or descriptors and appropriate sequential combinations of the descriptors. A sample search history is shown in Table 3-1. From these listings, abstracts were requested for approximately 650 references in the Engineering Index and 85 in the NTIS Index.

Simultaneously, a search was made for abstracts of pertinent articles in the computerized reference file of the Data Center of the Copper Development Association. CDA kindly furnished more than 120 abstracts.

After all of these abstracts were reviewed, Bechtel library personnel were asked to obtain copies of some 350 articles that appeared to be relevant to the study but which were not yet in the project files.

Next, a manual search was made of the Engineering Index from 1960 to 1970. This search employed those keyword descriptors found most productive during the computer search. Some 110 additional articles were discovered that were deemed pertinent and copies of those references were sought.

Table 3-1
TYPICAL COMPUTER SEARCH HISTORY

```

*****
*
*
*
*      Lockheed Retrieval Services
*
*
*
*****

```

User 965 Date:01/16/76 Time:10:13:43 File: 8

Search History		Print Summary				
Set	Items Description	No.	File	Accn/Set	Fmt	Item-range
1	9025 COPPER	1	8	34	5	1-409
2	12109 ALUMINUM	2	8	60	5	1-240
3	3554 STAINLESS (W) STEEL					
4	3836 TITANIUM					
5	75 ADMIRALTY					
6	8 MUNTZ					
7	920 BRASS					
8	511 BRONZE					
9	26194 1-8/OR					
10	8368 CORROSION					
11	10372 TUBE?					
12	1324 EROSION					
13	2801 9AND10					
14	763 9AND11					
15	133 9AND12					
16	2261 INSPECTION					
17	4579 VIBRATION					
18	26774 TESTING					
19	2081 CA=616					
20	42370 10OR12OR16OR17OR18OR19					
21	1681 20AND11					
22	1681 20AND11					
23	4905 13OR14OR15OR22					
24	0 WATER BOX					
25	0 WATERBOX					
26	0 WATER BOXES					
27	0 WATERBOXES					
28	119 TUBE (F) SHEET	45	10077	35-44/OR		
29	11 TUBESHEET	46	0	CONDENS		
30	35 TUBE (F) SHEETS	47	62	FREDWATER (F) HEATERS		
31	6 TUBESHEETS	48	803	CONDENSER?		
32	153 28-31/OR	49	304	CONDENSING		
33	271 9AND11AND20	50	1047	48OR49		
34	409 32OR33	51	190	50AND11		
35	2803 CA=613	52	246	45AND50		
36	3759 CA=614	53	40	47AND45		
37	2706 NUCLEAR (F) POWER (F) PLANTS	54	280	52OR53		
38	6522 POWER (F) PLANTS	55	439	51OR54		
39	117 FOSSIL (F) PLANTS	56	802	34OR55		
40	82 FOSSIL (F) PLANT	57	6394	TUBES		
41	1168 POWER (F) STATION	58	301	55NOT57		
42	1032 POWER (F) STATIONS	59	132	57AND50		
43	315 CENTRAL (F) STATION	60	392	54OR59		
44	180 CENTRAL (F) STATIONS	61	36530	STUDY		

Additional articles were obtained during the field surveys and meetings with people in the industry.

As articles were received, each was given an accession number assigned in approximate order of receipt. For each article a catalog card was prepared which included the authors' names, title of the article, its reference citation, an abstract of the article, and a listing of its keyword descriptors. A typical file card is shown in Figure 3-1. The list of keywords used together with their identification numbers is given in Table 3-2. Articles that were not relevant to the study were discarded.

050
Newton, E. H.
"Survey of Condenser Tube Life in Salt Water Service" <u>The International Nickel Power Conference</u> , Wrightsville Beach, N. C. (May 1968)
1.2, 4.1, 5.0, 8.1 A survey of the service life of condenser tube alloys in salt water service was made during 1966 by Arthur D. Little, Inc. for the Office of Saline Water, U.S. Dept. of the Interior. It is part of a continuing study being carried out for OSW of the corrosion behavior of materials used in the construction of large multistage flash distillation type desalination plants. Electric power plants located on or near the sea coasts of the U.S. probably pump more sea water (or brackish water) collectively through their turbine condensers than any other single or group of heat exchanger users. Therefore, most of the effort in this survey was directed toward collecting, assembling and interpreting data generously given us by a significant portion of the electric utility companies who operate plants using sea or brackish water for cooling.

Figure 3-1. Typical Catalog File Card
(original is 5 by 8 inches)

As each article was processed, its list of references was reviewed against the existing catalog file. This produced an additional 100 references.

After nearly all of the known articles had been cataloged, etc. the information, except the abstract, was transferred from the file cards to punched cards to enable more efficient sorting, selection, and listings of the accumulated bibliography.

Table 3-2

LITERATURE SEARCH
KEYWORD LIST

1	CIRCULATING WATER TYPES	5	MATERIALS
	1.1 Freshwater		5.1 Aluminum
	1.2 Seawater		5.2 Admiralty
	1.3 Brackish Water		5.3 Aluminum Brass
	1.4 Polluted Seawater		5.4 Aluminum Bronze
	1.5 Polluted Brackish Water		5.5 Brass
	1.6 Cooling Tower		5.6 Copper and Its Alloys
	1.7 Cooling Pond/Spray Canal		5.7 Copper-Nickel
	1.8 Cooling Water Inlet		5.8 Stainless Steel
			5.9 Titanium
			5.10 Analysis
2	CONDENSER COOLING SIDE TREATMENT	6	FABRICATION METHODS
	2.1 Fouling		6.1 Tube Rolling
	2.2 Chlorine		6.2 Tube Welding/Explosive Welding
	2.3 Corrosion Inhibitors		6.3 Tube Repair
	2.4 On-Line Mechanical Cleaning		6.4 Coatings
	2.5 Off-Line Mechanical Cleaning		
	2.6 Off-Line Chemical Cleaning		
	2.7 Inlet Inserts		
3	CONDENSER DESIGN	7	LEAK DETECTION/LOCATION
	3.1 Heat Transfer		7.1 Foam Method
	3.2 Efficiency		7.2 Eddy Current/Probalog
	3.3 Fouling Factor		7.3 Condensate Conductivity
	3.4 Corrugated Tubes	8	MATERIAL TESTING
	3.5 Thin Wall Tubes		8.1 Generating Stations
	3.6 Auxiliary Equipment		8.2 Test Laboratories
	3.7 Steam Dumping		
4	CONDENSER FAILURE MODES	9	CONDENSER FAILURE IMPACT
	4.1 Corrosion		9.1 Economic (Cost of Retubing)
	4.2 Erosion		9.2 Physical
	4.3 Missiles/Mechanical		9.3 Failure Rate Data
	4.4 Vibration		9.4 Troubleshooting
	4.5 Misoperation		
	4.6 Pressures	10	ENVIRONMENTAL IMPACT
	4.7 Joints		10.1 Bioassays
	4.8 Ammonia Corrosion		10.2 Pollution
	4.9 Failure Analysis		

A second punch card file was established for unpublished literature such as internal memos and reports, which were obtained from the many contacts made with representatives of utility companies, condenser manufacturers, tubing manufacturers, etc.

A third punch card file was established for manufacturers' literature and catalog information related to condensers, condenser tubing, cleaning devices, and other accessory or peripheral equipment.

Results

The final bibliography, which contains 391 references listed numerically by accession number, is given in Appendix A. In this report, literature references are cited by this number.

The same bibliography listed alphabetically by author is given in Appendix B.

A keyword listing is given in Appendix C. In this listing, under each keyword descriptor number (Table 3-2), there is given the accession number of all reference articles to which the keyword is applicable. By successive cross-comparison of the accession number listings under two or more keyword headings, articles of increasingly specific subject content can be isolated.

Copies of all articles in the bibliography (except those with an asterisk following the accession number) have been transferred to EPRI, together with the catalog files and the punch card deck.

While all pertinent articles published since 1960 are not included in the bibliography, the search techniques were sufficiently comprehensive to have discovered a high proportion of the sought articles. In compiling the bibliography, only those articles having practical application to condenser tubing failures, condenser cleaning, and similar subjects related to the immediate scope of the study were included. Articles related to areas such as heat transfer, the more theoretical aspects of the metallurgy of condenser tube alloys, etc, were excluded.

The survey of the open literature revealed no comprehensive report of work comparable to the present study. The closest analog is the interesting and valuable work of Newton and Birkett (Ref 46 and 50) and Newton, Birkett, and Ketteringham (Ref 350). These surveys were sponsored by the Office of Saline Water, U.S. Department of Interior and were directed towards finding suitable tubing materials for seawater desalination plants. Most of the data in the first report (Ref 46) were drawn from the experience of power stations located at coastal sites. Accordingly, the study was limited to saline cooling waters and to alloys in common use in 1967.

MATRIX FOR SELECTION OF FIELD SURVEY STATIONS

Introduction

A crucial concern in making any survey based on a selected sample is that the surveyed sample must be representative of the whole if the results and conclusions derived from the sample are to have broad application.

Even a cursory review of the general parameters related to condenser tube deterioration suggests six or eight of prime significance (e.g., tube material, circulating water composition, etc). Subdivisions and combinations of these pointed to the need for a large survey sample. At the same time, however, limitations on schedule and budget placed a sharp constraint on the number of stations that could be included in the survey. Accordingly, a selection process had to be devised that would produce a representative sample of the significant parameters in sufficient quantity to form an adequate data base for analyses yet would be appropriate to the available time and money. To accomplish this critical task, a station selection matrix was prepared.

Station Selection Matrix

The station selection matrix grid contained 87 information fields of design, operation, and historical condenser performance data for each of 264 generating units at 87 power stations.

Many factors were considered in the preparation of the station selection matrix. Two important goals were: 1) to obtain a broad survey of operating experience with large, modern utility condensers; and 2) to emphasize in the survey new systems and materials that could be expected to be used in future applications.

EPRI in their Request for Proposal restricted the field survey to nuclear units larger than 100 MWe, fossil units larger than 600 MWe, and plants containing a significant number of titanium condenser tubes. However, because most of these plants are less than 5 years old and nearly all are less than 10 years old, it was decided to include a number of smaller fossil units. This was expected to reveal the performance characteristics of units whose ages exceeded 15 years. A detailed list of information items pertinent to the selection of stations was prepared. Originally it was intended that the matrix would be completed solely from data available in the literature, governmental reports, Bechtel files, etc, but it became evident that additional information was required, especially with regard to the availability and quality of station records and the stations' condenser leakage history. To obtain this information, it was decided to conduct a mail survey of a representative number of stations.

MAIL SURVEY

Selection of Sample

In the United States there are about 1000 steam-electric generating stations. However, 95 percent of the electrical output comes from about 600 stations which have some 2000 generating units. It was decided that for the purposes of this study, a representative profile would be obtained if 15 percent (about 90) of these stations were included in the mail survey.

Consistent with the EPRI criteria, a list was made of all stations with nuclear units over 100 MWe (turbine nameplate rating), all fossil stations with one or more units over 600 MWe, and all units with a significant portion of titanium tubes in the main condenser. Only stations in commercial service prior to January 1, 1975 were included. This list was supplemented with older, smaller fossil stations chosen at random. The completed list contained 97 stations with 290 generating units. Fifty-six operating utilities were represented in the list.

The distribution of these stations with regard to parameters important to the study will be described in the summary section below.

Mail Survey Form

To elicit a timely response from the maximum number of stations, a short, two-page mail survey form was developed. This form placed emphasis on those data which would be important in selecting stations for field survey but were not readily obtainable otherwise. The mail survey form is attached as Appendix D.

Mail Survey Response

The response to the mail survey questionnaire was excellent. In keeping with the cooperative nature of the electric utility industry, a great majority of the solicited stations responded promptly. A telephone follow-up campaign produced replies from most of the others. Eighty-seven stations with 254 generating units responded. This response was 89.7 percent of the stations and 91.0 percent of the generating units to which the questionnaire had been mailed.

The data obtained by the mail survey fulfilled the original objective and enabled completion of the detailed Station Selection Matrix.

Summary

A partial Station Selection Matrix is included as Appendix E. All station names, locations, and other identifying data have been deleted. Nonetheless, the raw data base could be valuable to those who may wish to analyze it for results beyond those given in this report. The descriptions of the matrix information fields together with the abbreviations used in encoding are given in Appendix F. The nine information fields marked with an asterisk are not included in Appendix E.

A profile of the 264 generating units in the selection matrix with regard to parameters relevant to the deterioration and failure of condenser tubes is given in Tables 3-3 and 3-4. Table 3-3 shows the distribution by age for each fuel type. Table 3-4 shows the distribution of condenser tube material in the condensing section for each cooling water classification.

Table 3-3

STATION SELECTION MATRIX
AGE DISTRIBUTION BY FUEL TYPE
Numbers of Generating Units

AGE RANGE YEARS	FUEL TYPE				PERCENT IN AGE RANGE
	BWR	PWR	FOSSIL	ALL	
1- 4.9	8	18	50	76	28.8
5.0- 9.9	4	5	37	46	17.4
10.0-14.9	0	2	34	36	13.6
15.0-19.9	1	0	32	33	12.5
20.0-29.9	0	0	56	56	21.3
>30	0	0	17	17	6.4
ALL AGES	13	25	226	264	
PERCENT EACH FUEL	4.9	9.5	85.6		100.0

Additional findings from the mail survey are reported in subsequent sections.

Table 3-4
STATION SELECTION MATRIX
CONDENSER TUBE MATERIAL BY COOLING WATER CATEGORY
Number of Generating Units

CONDENSER TUBE MATERIAL*	COOLING WATER CATEGORY**				PERCENT EACH ALLOY
	FRESH	CLOSED	SALT	ALL WATERS	
Admiralty***	103	16	2	121	45.8
SS Type 304	25	22	0	47	17.8
SS Type 316	0	0	1	1	0.4
90-10 Cu-Ni	5	3	14	22	8.3
70-30 Cu-Ni	0	0	6	6	2.3
Aluminum Brass	0	0	37	37	14.0
Aluminum Bronze	0	0	8	8	3.0
Titanium	0	1	9	10	3.8
Other [†]	11	1	0	12	4.6
ALL MATERIALS	144	43	77	264	
PERCENT EACH WATER	54.5	16.3	29.2		100.0

*Present material in condensing section.

**Fresh includes only once-through cooling mode.

Closed includes all cooling towers, closed ponds, and other recirculating systems.

Salt includes seawater and brackish water.

***All types of admiralty are included.

[†]Includes red brass (5), muntz (2), arsenical copper (4), and brass (1).

FIELD SURVEY

Criteria for Selection of Survey Stations

By an analytical review of the station selection matrix, 30 stations were chosen for field survey. Evaluation of the selected sample showed that 30 stations gave adequate opportunity for collection of data on all parameters of significance to the study within the time and budget constraints.

The following criteria were used in selecting the survey stations and were applied approximately in the order listed.

Fuel Type. Emphasis was placed on nuclear stations since their relative numbers will probably increase in the future. Eleven nuclear stations were chosen. Of these, four were BWRs and seven were PWRs, which is nearly the existing ratio between the two major types of nuclear systems.

Cooling Water Category. Stations having closed cycle cooling systems were preferred for study because such systems can be expected to be predominant in the future. Also, emphasis was given to stations that used brackish water or seawater for cooling because this environment has had a higher incidence of condenser tube failures and because the impact of condenser leakage on plant operations is more severe.

Condenser Tube Material. Special care was taken to assure that all of the principal condenser tube alloys were adequately represented in the survey sample. However, the sample selection was weighted to emphasize stations that had a significant number of titanium tubes as well as stations having stainless steel or copper-nickel tubes in the main condensing section.

Unit Size and Ages. In selecting stations with fossil fuel units larger than 600 MWe, preference was given to those which had older, smaller units on the site in order to broaden the age data base while keeping the number of survey trips to a minimum. Also preferred were stations where two or more condenser tube materials were or had been in service under the same conditions.

Records Quality and Availability. Stations were preferred if their mail survey response indicated that they had acceptable records that would be available to the survey team. The mail survey responses to the records-related questions were rated and reduced to a letter grade. The results are plotted in Figure 3-2.

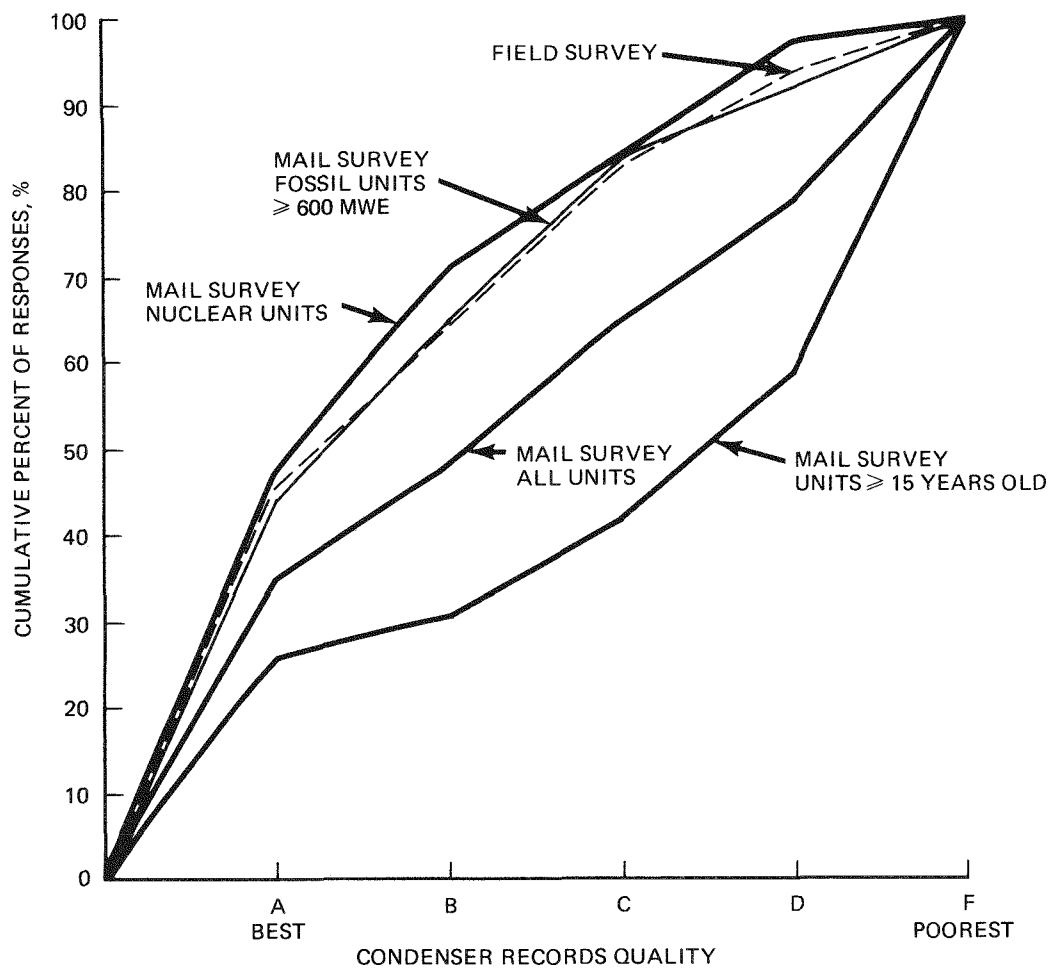


Figure 3-2. Mail Survey Results of Condenser-Related Records

Condenser Manufacturer. The tentative selection list defined by the above criteria was reviewed to ascertain whether the several condenser manufacturers were proportionately represented.

Condenser Failure History. Newer stations that reported few if any condenser tube failures in the mail survey were not included in the field survey.

Station Location. The selection list was reviewed to ensure that excessive time and travel would not be necessary.

As the field survey work progressed, the list of stations and survey schedule was revised as dictated by early results and the availability of stations to suit the survey schedule.

Characteristics and Validity of Survey Sample

The 30 stations surveyed had 76 generating units. The median age of the generating units was 12.1 years, and the median generating capacity was 476 MWe. The 76 unit condensers included 116 condenser shells which contained 294 tubing bundles. In all, these condensers had 2,288,722 tubes with a total surface area of 23,189,000 square feet. There were over 15,000 lineal miles of condenser tubing.

Tables 3-5 and 3-6 give the same correlations for the Field Survey Stations as were given in Tables 3-3 and 3-4 for the stations in the selection matrix. Table 3-5 shows the number of generating units in each age range for each fuel type. Table 3-6 shows the number of generating units using each condenser tube alloy versus the cooling water category. Additionally, Table 3-7 shows the unit age by generator size distribution for the field survey.

Table 3-5

FIELD SURVEY STATIONS
AGE DISTRIBUTION BY FUEL TYPE
Number of Generating Units

AGE RANGE YEARS	FUEL TYPE				PERCENT IN EACH AGE RANGE
	BWR	PWR	FOSSIL	ALL	
1- 4.9	1	6	11	18	23.7
5.0- 9.9	4	3	15	22	29.0
10.0-14.9	0	0	14	14	18.4
15.0-19.9	1	0	14	15	19.7
20.0-29.9	0	0	7	7	9.2
≥ 30	0	0	0	0	0.0
ALL AGES	6	9	61	76	
PERCENT EACH FUEL	7.9	11.8	80.3		100.0

Notes

1. 36.7 percent of stations surveyed were nuclear.
2. 20 of the 61 fossil units surveyed were larger than 600 MWe.
3. 10 of the 15 nuclear units surveyed were larger than 600 MWe.

Table 3-6

FIELD SURVEY STATIONS
CONDENSER TUBE MATERIAL BY COOLING WATER CATEGORY
Numbers of Generating Units

CONDENSER TUBE MATERIAL*	COOLING WATER CATEGORY**				PERCENT EACH ALLOY
	FRESH	CLOSED	SALT	ALL WATERS	
Admiralty***	29	6	0	35	46.1
SS Type 304	7	3	0	10	13.2
SS Type 316	0	0	1	1	1.3
90-10 Cu-Ni	2	0	11	13	17.1
70-30 Cu-Ni	0	1	1	2	2.6
Aluminum Brass	0	0	1	1	1.3
Aluminum Bronze	0	0	5	5	6.6
Titanium	0	0	9	9	11.8
Other	0	0	0	0	0.0
ALL MATERIALS	38	10	28	76	
PERCENT EACH WATER	50.0	13.2	36.8		100.0

*Present material in condensing section.

**Fresh includes only once-through cooling mode.

Closed includes all concentrating cycles with freshwater makeup.

Salt includes all seawater and brackish water cycles.

***All types of admiralty are included.

Table 3-7

FIELD SURVEY STATIONS
AGE DISTRIBUTION BY GENERATOR SIZE
Number of Generating Units

AGE RANGE YEARS	GENERATOR NAMEPLATE RATING, MWe						PERCENT EACH AGE RANGE
	<49.9	50-99	100-299	300-599	600-999	>1000	
1- 4.9	0	0	0	5	11	2	23.7
5.0- 9.9	0	0	1	8	12	1	29.0
10.0-14.9	0	0	5	5	4	0	18.4
15.0-19.9	1	1	11	2	0	0	19.7
20.0-29.9	3	2	2	0	0	0	9.2
>30	0	0	0	0	0	0	0.0
ALL AGES	4	3	19	20	27*	3**	
PERCENT EACH SIZE	5.3	3.95	25.0	26.3	35.5	3.95	100.0

*Includes five BWR and five PWR units.

**All three units are fossil fueled.

The station selection matrix does not present a typical profile of all generating units in the United States. It is, however, representative of large modern power generating units and provides an excellent yardstick by which to assess the validity of the selected field survey sample. Comparisons of the generating units in the station selection matrix with those in the field survey are made in Tables 3-8, 3-9, and 3-10.

Table 3-8 shows the percentage of units in each data base for the correlation between unit age and fuel type. As would be expected from the criteria used for their selection, the field survey stations show a higher ratio of nuclear to fossil units and an emphasis on stations in the 5-to-20-year age range. The comparison of condenser tube material with cooling water category given in Table 3-9 shows the heavier weighting given to 90-10 Cu-Ni and titanium. It also shows that less than the intended weighting was given to stainless steel alloys, especially in closed cooling systems. This was largely because such stations are relatively new and have insufficient meaningful experience.

However, this was compensated in part by the many stainless steel air removal sections that were surveyed. As will be brought out in Section 5, more information was obtained for the aluminum brass/bronze alloys than is indicated on the list of tube materials. At a number of the surveyed stations, data were obtained on original tube sets of these alloys which have been replaced with another material. Admiralty, which is by far the predominant material used in freshwater condensers, was included in the field survey in the same ratio as it exists in the selection matrix. The field survey emphasized seawater cooled systems as intended but contained a lower ratio of closed cooling systems because most such stations have been built more recently.

Table 3-10 tabulates the distribution of condenser manufacturers for the mail survey and the field survey. The distribution in the field survey was representative for the major manufacturers.

Table 3-8

COMPARISON OF STATION SELECTION MATRIX WITH FIELD SURVEY
AGE DISTRIBUTION BY FUEL TYPE
Percent of Generating Units in Each Sample

AGE RANGE YEARS	FUEL TYPE							
	BWR		PWR		FOSSIL		ALL	
	SSM*	FIELD**	SSM	FIELD	SSM	FIELD	SSM	FIELD
1- 4.9	3.0	1.3	6.8	7.9	19.0	14.5	28.8	23.7
5.0- 9.9	1.5	5.3	1.9	3.9	14.0	19.8	17.4	29.0
10.0-14.9	0.0	0.0	0.8	0.0	12.9	18.4	13.6	18.4
15.0-19.9	0.4	1.3	0.0	0.0	12.1	18.4	12.5	19.7
20.0-29.9	0.0	0.0	0.0	0.0	21.2	9.2	21.3	9.2
≥ 30	0.0	0.0	0.0	0.0	6.4	0.0	6.4	0.0
ALL AGES	4.9	7.9	9.5	11.8	85.6	80.3	100.0	100.0

*Station Selection Matrix contains 87 stations with a total of 264 generating units.

**Field survey includes 30 stations with a total of 76 generating units.

Table 3-9

COMPARISON OF STATION SELECTION MATRIX WITH FIELD SURVEY
CONDENSER TUBE MATERIAL BY COOLING WATER CATEGORY
Percent of Generating Units in Each Sample

CONDENSER TUBE MATERIAL	COOLING WATER CATEGORY							
	FRESH		CLOSED		SALT		ALL WATERS	
	SSM**	FIELD***	SSM	FIELD	SSM	FIELD	SSM	FIELD
Admiralty†	39.0	38.2	6.0	7.9	0.8	0	45.8	46.1
SS Type 304	9.5	9.2	8.3	4.0	0	0	17.8	13.2
SS Type 316	0	0	0	0	0.4	1.3	0.4	1.3
90-10 Cu-Ni	1.9	2.6	1.1	0	5.3	14.5	8.3	17.1
70-30 Cu-Ni	0	0	0.4	1.3	1.9	1.3	2.3	2.6
Aluminum Brass	0	0	1.5	0	12.5	1.3	14.0	1.3
Aluminum Bronze	0	0	0	0	3.0	6.6	3.0	6.6
Titanium	0	0	0.4	0	3.4	11.8	3.8	11.8
Other	4.2	0	0.4	0	0	0	4.6	0.0
ALL MATERIALS	54.6	50.0	16.2	13.2	29.2	36.8	100.0	100.0

*Present material in condensing section.

**Station Selection Matrix contains 87 stations with a total of 264 generating units.

***Field survey includes 30 stations with a total of 76 generating units.

†Includes all types of admiralty.

Table 3-10

COMPARISON OF STATION SELECTION MATRIX WITH FIELD SURVEY
DISTRIBUTION BY CONDENSER MANUFACTURER
Percent of Generating Units in Each Sample

CONDENSER MANUFACTURER	STATION SELECTION MATRIX*	FIELD SURVEY**
Allis-Chalmers	0.4	5.3
Baldwin-Lima-Hamilton	3.4	3.9
CH Wheeler	4.9	7.9
Foster-Wheeler	22.3	25.0
Ingersoll-Rand	21.6	22.4
Lummus	0.8	1.3
Maryland Drydock & SB	0.4	0.0
Southwest Engineering	2.7	2.6
Westinghouse	16.7	26.3
Worthington	8.3	5.3
Yuba	1.1	0.0
Not Indicated	17.4	0.0
NUMBER OF UNITS	264	76

*Station Selection Matrix contains 87 stations with a total of 264 generating units.

**Field survey includes 30 stations with a total of 76 generating units.

Field Survey Form

A comprehensive and orderly field survey form was developed for use by the survey teams. The form was designed with the following purposes in mind:

- To serve as a checklist and guideline for the efficient conduct of each survey
- To provide for the collection of all pertinent data and thereby minimize the need for followup work
- To avoid the collection of peripheral or irrelevant data
- To promote standardization of data collection by different survey teams.

The 30-page field survey form was organized in seven sections:

1. General Station Data
2. Document Request List
3. Condenser Design Data
4. Chemistry - Cooling Water and Turbine Cycle
5. Condenser Operation, Maintenance, and Repair
6. Condenser Leakage Impact
7. Additional System and Equipment Data

A form was completed for each generating unit surveyed at the station. The entire form is given in Appendix G.

Procedure for the Field Surveys

The field surveys were conducted by multidisciplined teams of 1 to 3 engineers. Metallurgists, mechanical engineers, and water chemistry specialists were assigned to each team in accordance with the conditions anticipated at each station as determined from the station selection matrix and preliminary telephone contacts. In some instances, one senior staff specialist of the most appropriate discipline conducted the entire survey.

Each selected station was telephoned to arrange the schedule and advised of the information needed. When time allowed, the survey form and other information were sent to the station in advance to assist their preparation for the survey. All of the survey stations were very cooperative. The typical visit consisted of two engineers on site for two days.

After the first several field surveys, it became evident that detailed quantitative data for all of the desired areas could not be obtained in the 3 to 5 days devoted to each field survey. It was found that nearly all stations had quite accurate records of the number (and usually the location) of plugged tubes. Some stations did not log the date on which the tubes were plugged. In other cases, the only time-oriented record consisted of colored symbols on tubesheet drawings where the color indicated the date. Such drawings cannot be readily reproduced and to make a take-off tabulation would require excessive time. It was also found that reliable, detailed records of the cause of the tube failure were not available at many stations.

It was also found that only a few stations had calculated and recorded the inleakage flow rate for individual condenser leaks. At most stations, the data to enable such calculations probably are in the stored records. However, to bring together (from various depositories) the several necessary records, and to time-synchronize them would require approximately one week of effort for each condenser-year studied.

In conjunction with most surveys, a visit was made to the headquarters engineering department of the operating utility. This enabled collection of valuable data not attainable on site with regard to not only the surveyed station but also other stations in the system. A wealth of information was obtained in the form of operating records, company reports, literature references, etc.

To supplement the information gained from the operating utilities, several meetings were held with manufacturers of condensers and condenser tubing. Again, excellent cooperation was accorded to the field survey personnel and an abundance of data, research reports, literature references, and design experience were obtained.

DATA MANAGEMENT SYSTEM

To cope with the literally hundreds of thousands of information items obtained in the course of the study required development of an effective computerized data management system. Such a system had to enable efficient and rapid sorting, arraying, correlating, averaging, tabulating, etc., of the data bank. To do this, a matrix tabulation was devised to contain all of the relevant alphanumeric data from the field survey which were subject to encoding.

The field survey matrix is schematically illustrated in Figure 3-3. The matrix column headings consist of 198 information fields. Each of these is defined and the abbreviations used of encoding are given in the Description of Information Fields in Field Survey Matrix, Appendix H. The information fields were ordered roughly by subject areas. From left to right these are: Station Data; Unit Data; Condenser Design Data; Condenser Tubing Data; Failure Rate Data; Leak Detection, Location, and Repair Data; and Data on other Equipment.

The entered data on each line in the matrix are descriptive of an individual tubeset. As discussed in Section 2, a condenser has three primary service zones or regions, namely: impingement, air removal, and condensing. In many condensers, the tubing material used in the impingement and/or air removal zone is different from that used in the main condensing zone. The tube failure mechanism and the rate of tube failures can also be markedly different in each zone as well as for each material. Furthermore, a number of the condensers surveyed had been retubed in whole or in part one or more times. It follows then that to have rational and comparable tube failure data, the tubes in any given condenser must be broken down into individual tubesets of the same material and in the same service.

For the condensers surveyed in the field, 684 tubesets were identified; hence the final matrix contained 684 lines. The total matrix had space available for 135,432 information items. Many of these were repetitive for all tubesets at a given station or for a given generating unit, and for many others the information was not available.

The raw data from the field survey forms were transferred to punch cards. Twelve punch cards were required to accommodate the 198 information fields. A set of 12 cards was prepared for each of the 684 tubesets. The deck of 8208 punch cards was used to load the matrix into the computer.

The data bank was manipulated for sorts, arrays, and various operations by System 2000* (version 2.8), a broadly applicable data management system developed by MRI Systems Corporation of Austin, Texas. System 2000 was

*System 2000 is a registered service mark.

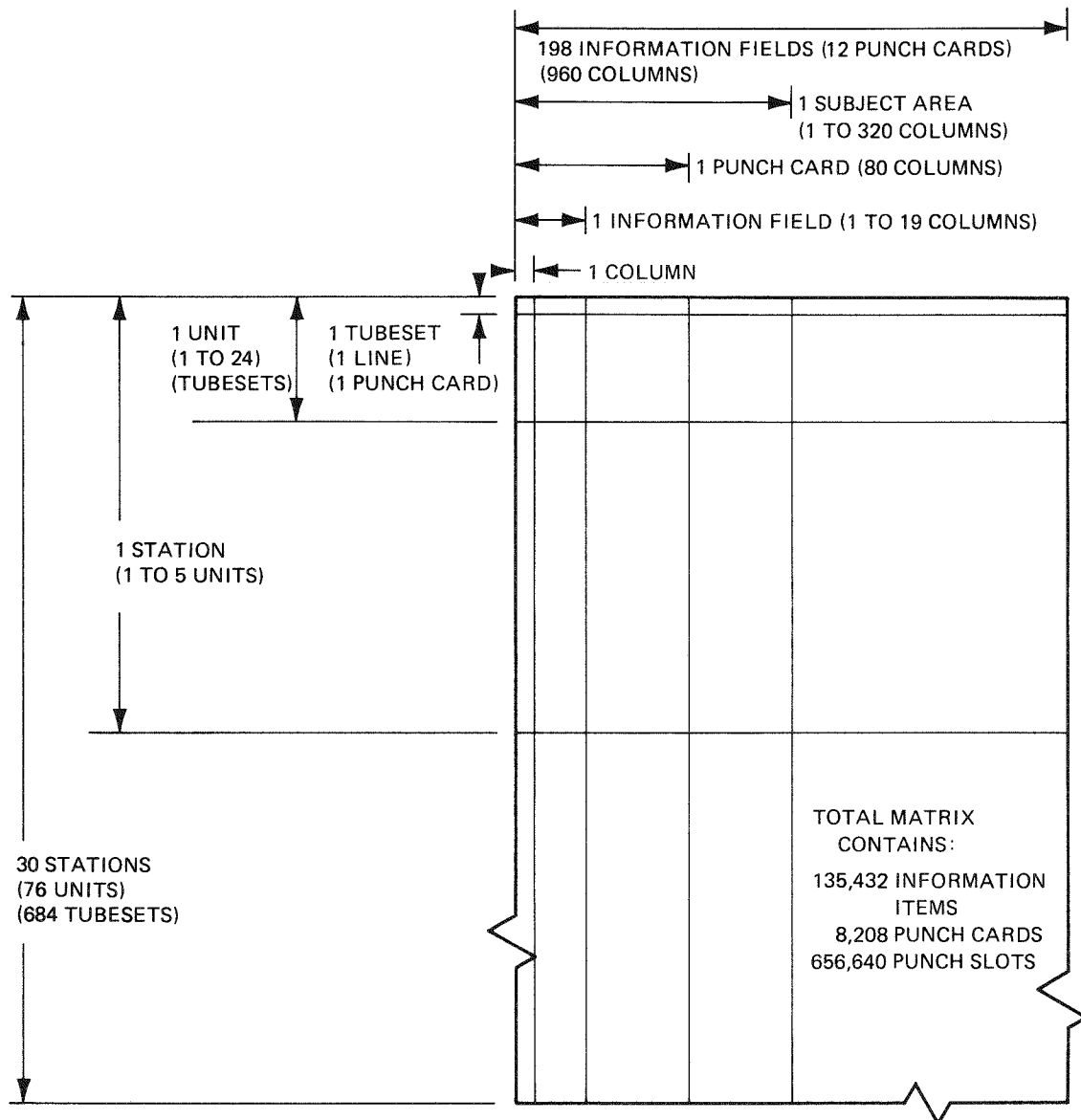


Figure 3-3. Data Management Matrix

chosen because of its suitability for the problems at hand and because it is available through many time-sharing or data management firms. The punch card deck together with a magnetic tape containing the data bank and the adoption routines for System 2000 have been turned over to EPRI.

A partial field survey matrix is given in Appendix I. All station names, locations, unit numbers, and other readily identifiable items have been deleted; thirty-one information fields have been deleted. These are designated by an asterisk preceding the field number in the listing given in Appendix H. To make this matrix more useful to the reader, it has been sorted sequentially by tubing material (field 49), condenser service area (field 170), cooling water category (field 171), and arrayed in ascending numerical order of the terminal, total failure rate (FRT - field 124). The terminology is defined in Appendix H and discussed in Section 5.

The station selection matrix was prepared by essentially the same technique and also adapted for manipulation by System 2000. A punch card deck and magnetic tape similar to that for the field survey matrix also has been delivered to EPRI. This facilitates future use of either data base by EPRI or its designee.

Section 4

CONDENSER OPERATION AND MAINTENANCE FINDINGS

INTRODUCTION

A condenser may affect plant performance as a result of the following deficiencies:

- Reduction of heat transfer capability
- Reduction of deaeration efficiency
- Loss of integrity (inleakage of air or water)

To protect against potential problems, the condenser and its related systems are operated and maintained in accordance with the prevailing conditions. Specific plant parameters such as circulating water composition and condensate water quality specifications affect local operation and maintenance practices. More generally, however, such practices reflect broader needs and considerations which are reviewed below.

The major study findings of interest in condenser operation and maintenance are reviewed in this section of the report. The following topics are addressed:

- Circulating water inleakage and air inleakage from the viewpoint of their impact on the plant; their frequency, size, and duration; the methods used for their detection, location, and repair; and the procedures that seem most effective for their control.
- Various operating and maintenance considerations found to be significant in ensuring condenser integrity and high performance, such as tube cleaning methods used, including their required frequency of application and their effectiveness.
- An evaluation of current plant record-keeping practices.

CIRCULATING WATER INLEAKAGE

Water Leakage Impact

The mail and field surveys confirmed the general background of information collected as part of the literature search to the effect that circulating

water inleakage is detrimental to power plants for the following reasons:

- Circulating water impurities that enter the steam cycle as the result of condenser leakage contaminate the condensate, feedwater, steam generator water, and steam. Above some given leakage rate, which is a function of the impurity content of the circulating water and of the cycle water quality specifications, the faulty condenser or condenser section must be isolated and normal operation cannot be resumed until the leakage is repaired.
- The plant must be operated at part load or even completely shut down for some period of time. The leakage impact is therefore the cost of the repair plus the costs resulting from loss of plant availability and loss of energy generation.
- During plant operation with circulating water inleakage, additional costs are incurred to maintain the steam cycle streams within acceptable impurity limits. Cycle water quality is maintained by increasing the steam generator blowdown, by operating condensate polishers, or by a combination of the two. However, steam generator blowdown wastes valuable energy and requires some form of chemical processing, either for recycle or for replacement makeup water and, in some cases, for treatment prior to off-site discharge. Condensate polishers require either chemical regeneration or replacement of their ion exchange resins. Whatever purification process is used, additional operating costs are incurred until the leak is repaired.
- Finally, a condenser may deteriorate in service to the point that either its maintenance requirements make it uneconomical to operate as is, or its performance falls below acceptable levels in some regards (e.g., its air removal section may have so many plugged tubes that it does not collect and concentrate the noncondensable gases as effectively). At this point, the condenser is usually retubed totally or in part. As illustrated in Figures 4-1 and 4-2, however, retubing is a major operation which is costly in terms of both direct costs and loss of plant output.

In addition to the above impacts, condenser water inleakage may lower the performance and may accelerate the general degradation of other steam cycle components, mostly as the result of fouling and/or corrosion. The field survey findings strongly suggest that, with regard to sensitivity to leakage degradation, power plants should be grouped according to fuel type.

- Fossil fueled plants showed little apparent degradation. Some of the plants surveyed indicated that circulating water inleakage had contributed to some extent to solids deposition in the boiler. A few other plants estimated that part of the turbine deposits could be traced back to the same cause. It is very difficult to correlate water leakage to corrosion or fouling phenomena; yet it appears from the survey results

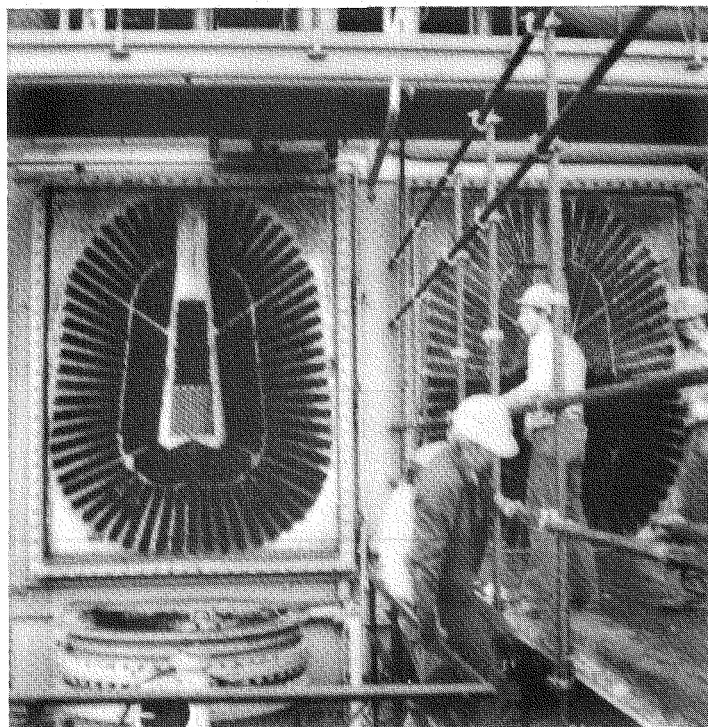


Figure 4-1. Condenser Retubing Work Area

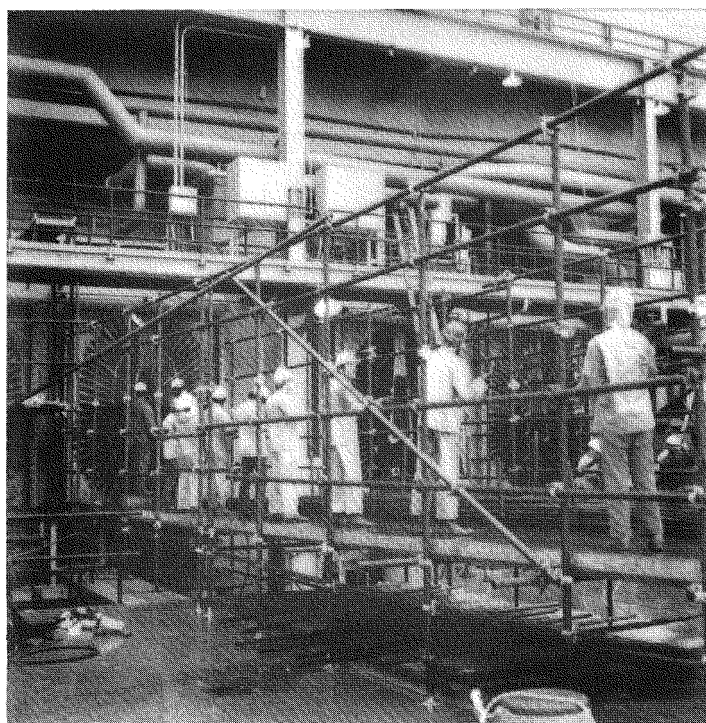


Figure 4-2. Condenser Retubing — Tube Pulling Operation

that fossil fueled plants that have been operated generally within their water quality specifications show no evidence of circulating water inleakage impact.

- The survey findings suggest that the above conclusion is also applicable to Boiling Water Reactor plants (BWRs); however, the data collected and analyzed for BWR plants was not sufficiently broad and detailed to allow a conclusion to be reached. Also, one of the BWR plants surveyed had major corrosion damage after an extended chemistry excursion during a period of leakage.
- The survey found that some Pressurized Water Reactor plants (PWRs) had significant damage in the steam generators, perhaps due in part to continued operation with condenser water inleakage. This observation was not the result of an evaluation by the survey team but was based on statements by plant personnel.

Water Leakage Frequency, Size, and Duration

The frequency of condenser water leakage occurrences is an indication of condenser integrity status, and it varies over a very wide range. Some of the plants surveyed had leakage occurrence frequencies in the range of once a decade; others had frequencies in the range of once a week. However, leakage frequency is not always a significant parameter for the following reasons:

- Many plants can continue to operate at full power, well within water quality specifications, even when the condenser is leaking, if they have relatively clean circulating water and have an efficient and high-capacity cycle purification system (steam generator blowdown and/or condensate polisher).
- Some plants can use sawdust to plug leaks on-line that would otherwise have to be repaired promptly.
- In most plants it is desirable during maintenance operations to plug not only the leaking tubes but also to guard plug the tubes that have a relatively high probability of becoming leakers (based on such considerations as proximity to defective areas or eddy current results).

Thus, leakage occurrence frequency is not a simple and direct indicator of plant outage due to condenser inleakage. It is also a difficult parameter to measure, and it is not generally tracked by operating plants. It could not be evaluated with accuracy from the data collected by the surveys.

The size or flow rate of condenser inleakage that can be tolerated during plant power operation also varies over a very wide range, mostly as a function of the circulating water composition and of the plant cycle purification system's capacity and efficiency. For example, one of the fossil plants

surveyed had been operating for several weeks with a completely sheared tube that was leaking more than 200 gallons a minute; on the other hand, one of the nuclear plants surveyed was ramped down for repair after it had operated for a few hours with a leak of less than 0.01 gallon a minute. Thus, no precise statement can be made with regard to acceptable leak rates unless all the relevant plant parameters are known.

It was observed that plants cooled by seawater or brackish water are generally limited to leakage rates in the range of a few tenths of a gallon a minute or less, but open-cycle freshwater plants can continue full power operation with leakage rates of several tens of gallons a minute. Nuclear plants generally tolerate less leakage than fossil plants.

Condenser water leakage durations are also distributed over a wide range and are a function of the parameters referred to above. The data collected during the surveys showed that the rate of growth of any given leak and therefore its allowable duration was a highly variable parameter even within a given plant. In addition, the data collected suggest that leaks grow very erratically and that with circulating water of high suspended solid content, temporary spontaneous leak plugging is not uncommon. Despite the large variability referred to above, seawater- or brackish water-cooled plants generally tolerate leakages lasting between a few hours and a couple of days, but open-cycle freshwater plants can usually continue unrestricted but prudent operation with water leakages lasting from several weeks to a few months.

Water Leakage Detection

Condensers are usually monitored for possible water inleakage by a combination of methods which fall into two categories. In the first category are those methods used during power operation. They are based on monitoring selected cycle streams for chemical changes. In the second category are those methods used during plant shutdown. They are generally highly sensitive in terms of detectable leak flowrate and are particularly valuable because they allow the locations of the leaks to be identified. Accordingly, they are described in the subsection, "Water Leakage Location," (see page 4-11) and the following paragraphs address only the on-line detection methods.

On-line methods are based on detecting the changes in cycle water chemistry that are induced by condenser leakage. When expressed in terms of leak flow rates, the sensitivity of any given method is directly related to the

circulating water composition, the inherent sensitivity of the equipment used, and to normal cycle chemistry fluctuations. From a practical viewpoint, the dominant consideration in monitoring water leakage is the ability to detect any leakage well before it has a significant effect on the plant chemistry. In particular, the size of the leak is not significant except as an indication of whether or not the leak can be readily located when the condenser is opened. There is little merit in developing and implementing a leak detection technique that has a sensitivity much greater than that required to identify the smallest leak which can be located and repaired. It is necessary to provide for the detection of the smallest leaks which can be located and repaired. Thus, most plants use detection and location techniques that have approximately the same sensitivities (see Figure 4-3).

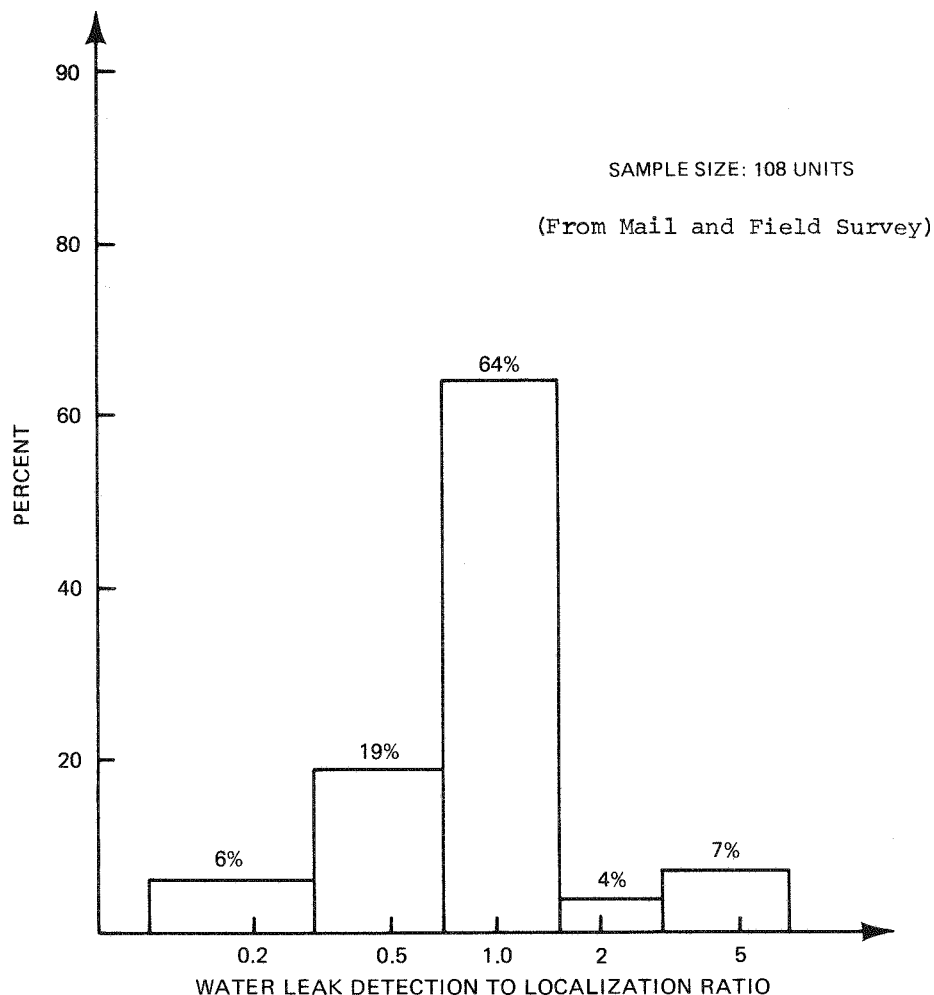


Figure 4-3. Plants Surveyed that Achieve a Given Condenser Water Leakage Detection-to-Localization Rate

In the following discussion, leakage detection sensitivities are defined as the changes in readings of monitored parameters that the plants considered to be meaningful indicators of condenser leakage. The discussion is presented in two parts; the first considers BWR plant cycles which use neutral water, and the second considers fossil and PWR plants which maintain a high pH throughout their cycle.

BWR Stations. All BWR plants use condensate straight conductivity monitors as the major indicators of potential condenser water leakage. These instruments have a low purchase and maintenance cost and are very sensitive and dependable. They are always installed at the condensate pump discharge and, in most cases, a number of cells are inserted in the hotwells. During plant steady power operation, this method is capable of producing the following sensitivities:

- A conductivity increase of 0.02 to 0.04 $\mu\text{mho/cm}$ is generally considered to be a reliable indication of abnormal condensate impurity levels and to justify an on-line investigation of possible contamination (including instrumentation checks, comparison of instrument readings, check of makeup water quality, and analyses of selected samples).
- An increase of 0.05 to 0.10 $\mu\text{mho/cm}$ is generally considered to be a reliable indication of condenser water inleakage and to justify a plant load reduction for location and repair at the earliest convenient time.

In addition, BWR plants always monitor reactor water very closely, particularly for chlorides. This gives an independent measurement of condenser water inleakage.

Fossil Fueled and PWR Plants. These plants use a variety of leakage detection techniques which are briefly described below. The frequency of utilization is also included.

Condensate Cation Conductivity. This is used as the primary condenser leakage indicator at 55 percent of the plants surveyed and as a secondary indicator at most of the other plants. It is based upon measuring the conductivity of the effluent from a hydrogen form cation exchange resin. (See Figure 4-4.)

Because it includes such a resin column, it has a slightly higher purchase cost and requires somewhat more attention and maintenance than the straight conductivity method. However, cation conductivity is also more sensitive than straight conductivity and is reported as dependable. As a result, it is a very efficient monitoring technique in modern fossil fueled and PWR plants

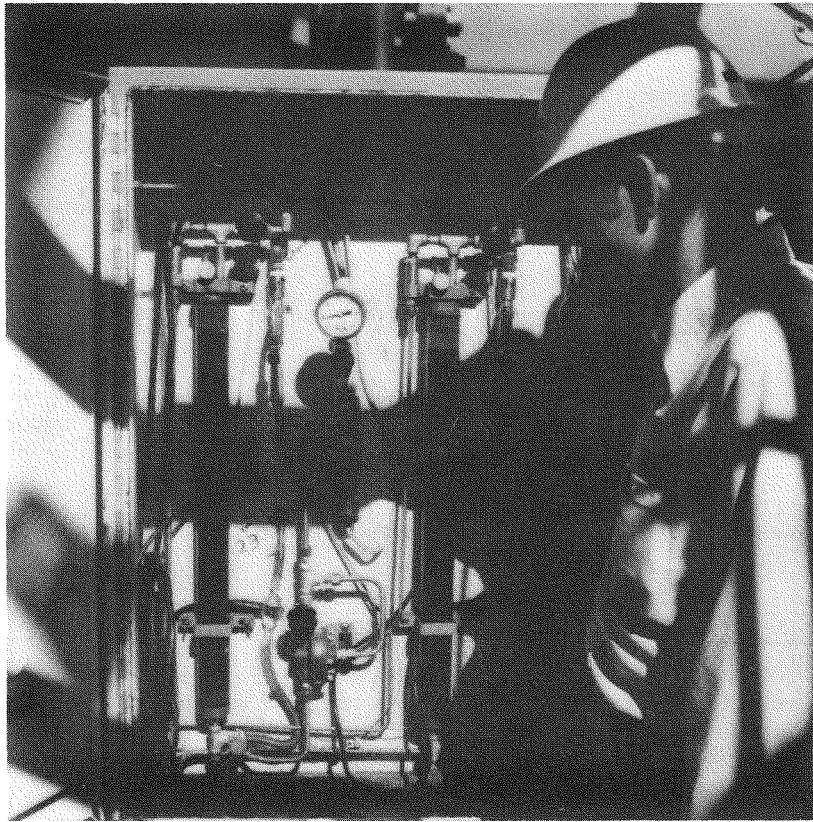


Figure 4-4. Cation Conductivity Instrument Resin Columns

which maintain a fairly high pH in their cycle and cannot use straight conductivity monitors. Consistent with BWR plant monitoring schemes, it is applied at least at the condensate pump discharge and, in difficult cases, at a number of sample lines taking samples directly out of the condenser. The survey indicates that, during plant steady power operation, the sensitivities are as follows:

- A cation conductivity increase of 0.05 to 0.10 $\mu\text{mho}/\text{cm}$ is generally considered to justify some on-line investigation of possible contamination.
- An increase of 0.10 to 0.20 $\mu\text{mho}/\text{cm}$ is generally considered to be a reliable indication of condenser leakage.

At each of the above levels, actions similar to those described for BWR plants are usually implemented in fossil and PWR plants.

In addition to condensate monitoring, fossil and PWR plants which use drum-type steam generators usually also monitor drum water and thus obtain a second set of measurements that can be used as indicators of condenser water leakage. The condensate impurity level at which condenser leaks are identified is shown in Figures 4-5 and 4-6.

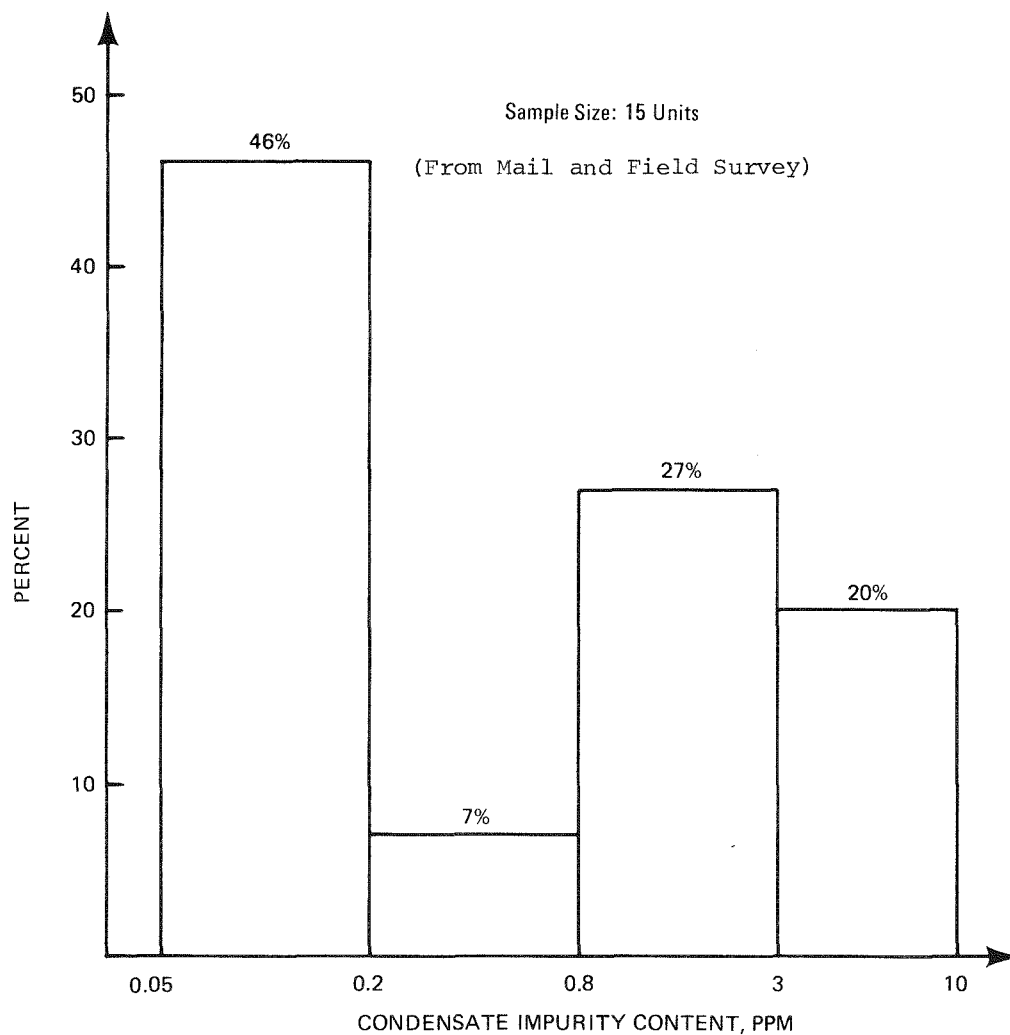


Figure 4-5. PWR Plants Surveyed That Detect Condenser Water Leakage at a Given Bulk Condensate Impurity Content

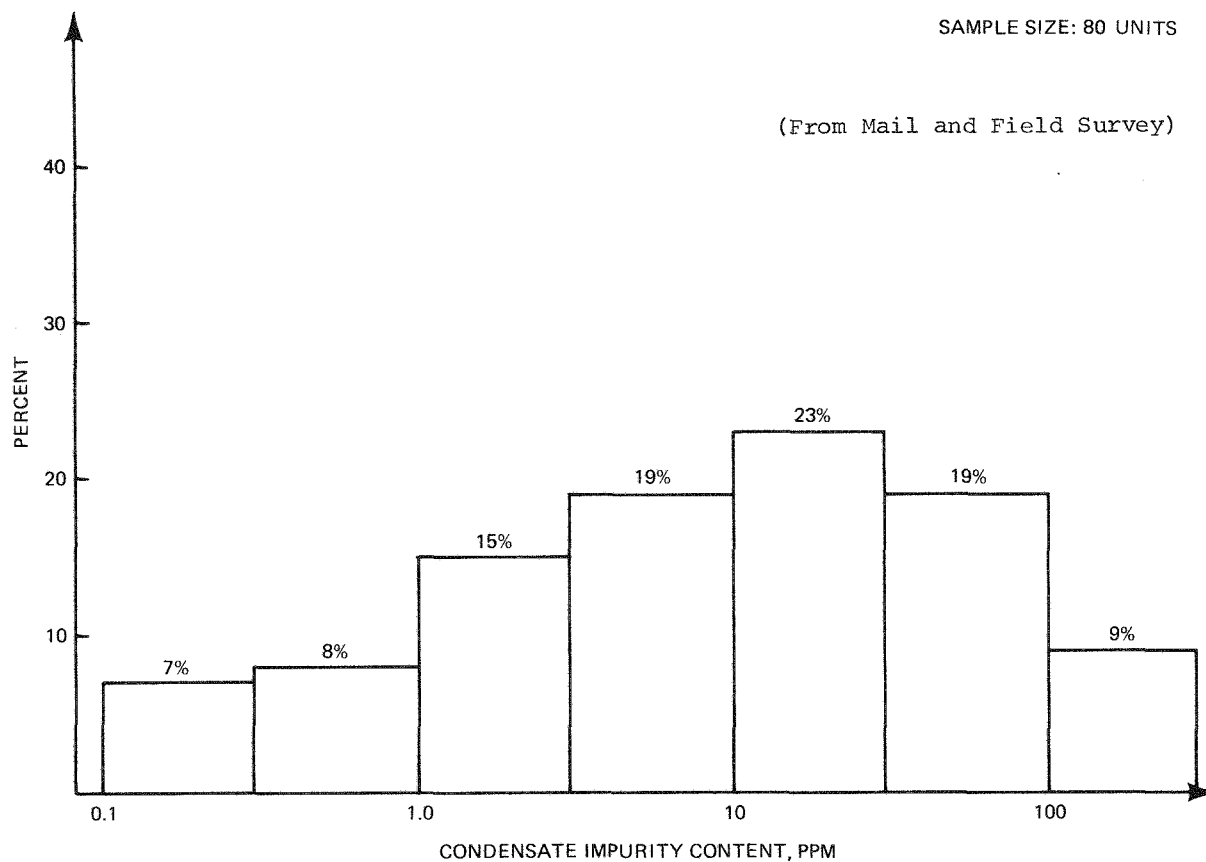


Figure 4-6. Fossil Plants Surveyed (>150MWe) That Detect Condenser Water Leakage at a Given Bulk Condensate Impurity Content

Straight Conductivity. This is used at 17 percent of the plants surveyed. Older and smaller fossil plants which maintain their condensate at a pH only slightly above neutral rely upon this method. In this application, the straight conductivity method is used as described for BWR plants.

Other Methods. The remaining fossil and PWR plants surveyed (28 percent of the total) use the following primary indicators for condenser water leakage monitoring: silica (11 percent); sodium (6 percent); steam generator drum general chemistry parameters (5 percent); steam generator drum chloride (3 percent); hardness (2 percent); some combinations of the cycle chemistry parameters (3 percent). These methods were selected for the most part because of rather unusual conditions prevailing at the plants where they are used. As a rule they are not of general interest and are not further discussed in this report.

The sodium method is not subject to the same limitation and is further evaluated. Its sensitivity during steady power operation was reported to be in the range of 1 ppb for a reliable indication of abnormal condensate impurity level and 2 to 3 ppb for a reliable indication of condenser leakage. At many plants, the circulating water composition is such that the sodium method would be capable of detecting and tracking leakages smaller than those which could be monitored by cation conductivity measurements.

Until now the sodium method has not been applied to a large extent because it has relied on equipment that has required extensive operating and/or maintenance care (early sodium selective electrode instruments and atomic absorption analyzers). Reportedly, both types of sodium instrumentation have recently been substantially improved. In the future, condenser water leakage may be monitored more frequently by measurements of selective cations, particularly sodium.

Water Leakage Location

Two categories of methods are available for locating condenser water leaks. *Prelocation methods* are applicable chiefly to large, modern condensers. They are aimed at defining the general area of the leakage. *Localization methods* are applicable to all condensers. They are aimed at defining the leak location to the full extent required for leak repair. Some of these methods are also used for detecting small leaks. All of them are normally implemented just before the leak repair work is performed and as part of the same maintenance operation.

Prelocation and localization methods are based upon creating some pressure differential between the steam side and the circulating water side and detecting the resultant flow of water, air, or some other gas. The resultant flow is directly related to the operating circulating water leakage, but it is not equal to it. Many location methods rely on detecting the air inleakage induced by the condenser vacuum. Figure 4-7 shows this air inleakage rate as a function of postulated leak hole size; it also shows, as a function of hole size, the operating water leak rates for three typical water-box pressures. The figure illustrates that the sensitivity of vacuum-based location techniques is a function of operating water-box pressure when expressed in terms of detectable operating water leak rate.

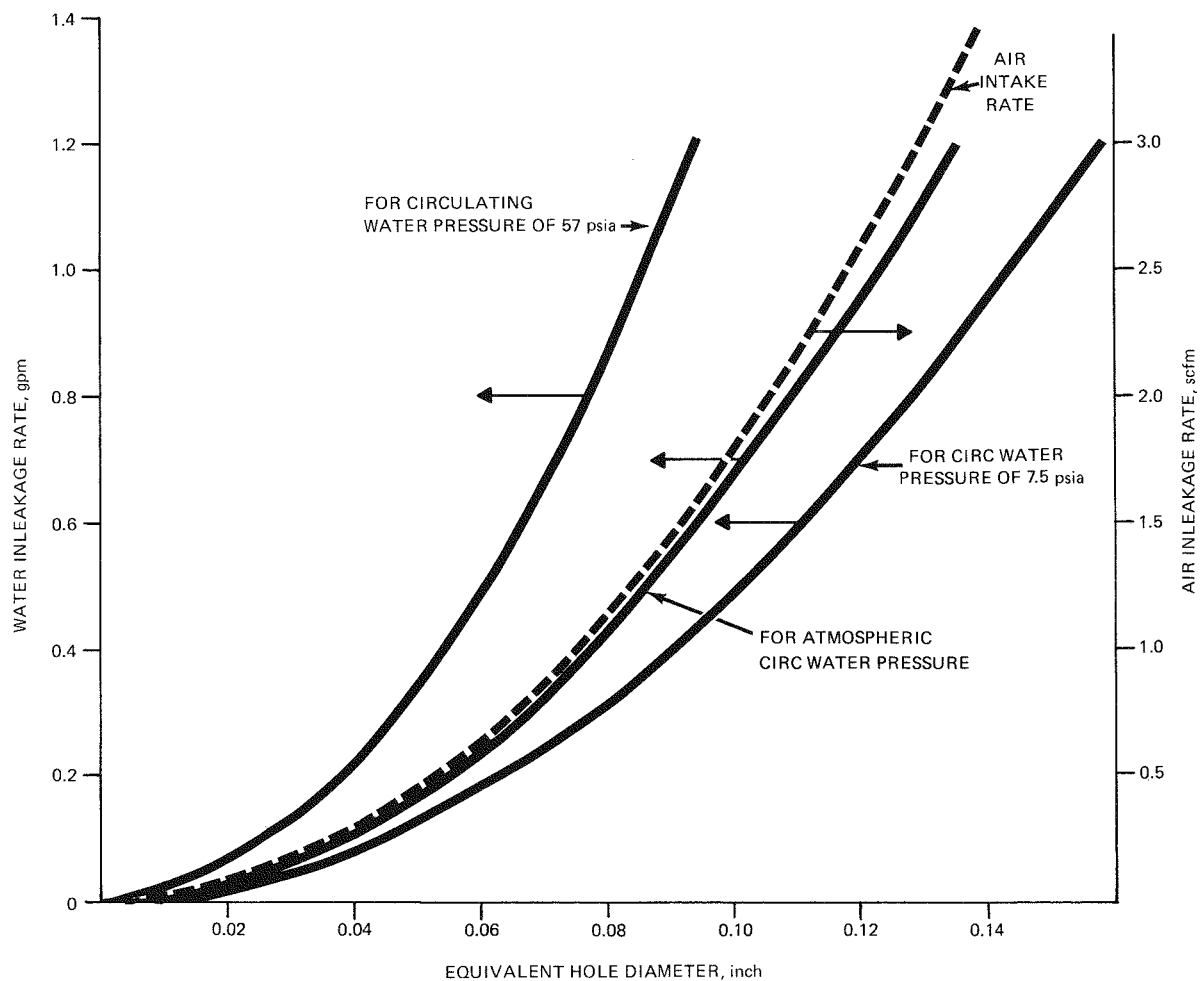


Figure 4-7. Air and Water Inleakage Rates for a Condenser with 1.7 inch Hg Backpressure

Data collected during the surveys indicate that the following prelocation techniques are most commonly used:

- In condensers that have several parallel circulating water streams, the first prelocation step is to identify the stream from which the leakage takes place. The plant load is reduced to permit operation with one stream shut down and each stream is temporarily isolated and drained. If the purpose is to prelocate gross leakage, it is sufficient to follow the leakage detection instrumentation response. When the leak or leaks are uncovered, circulating water impurities can no longer enter the cycle but air is allowed to enter the condenser. The off-gas flowmeter, if available, responds almost immediately to the change; however, it is not a very sensitive instrument and can detect only very large leaks. Water chemistry instrumentation is more sensitive, but its response may be distorted for a time by a temporary buildup of impurities in the condenser hotwell. The buildup takes place between the time the circulating water flow is interrupted and the time the leak is uncovered.
- As an alternative to the above, the faulty circulating water stream may be identified by injecting freon into the desired circulating water lines and setting a freon detector at the condenser off-gas outlet. This method was reported by several plants as being both dependable and sensitive enough for their needs.
- In a refinement of the above two methods, plants that can adjust and measure water box levels have used these measurements to estimate the approximate height of the leaks. Neither method is very effective for small or multiple leaks.
- Finally, some condensers are internally partitioned and fitted with sample lines. Normal sample monitoring allows the detection of leaking impurities before they are diluted by the bulk of the condensate flow and allows identification of the faulty condenser section. This identification must be confirmed before undertaking any corrective action since experience indicates that cross-contamination is not unusual when a leak develops at or near a condenser section interface.

The surveys also show that most plants determine the exact location of condenser water leaks by one or more of the following well-known localization techniques, all of which require direct access to the condenser tubesheets:

- Vacuum-related methods are used with the condenser steam side under normal operating vacuum. The most commonly used methods consist of applying, on corresponding areas of opposite tubesheets, a material such as plastic film, detergent foam, wet paper, or light paste which can seal tightly on the tubesheet and be drawn in by the vacuum resulting from a leak. The most successful are the use of plastic films or heavy foams. Heavy foam is capable of locating water leaks as low as 0.01 gpm in condensers operating with low circulating water pressure.

- Other vacuum-related techniques of interest rely on pressure gauges, air bubbles, flame indicators, or ultrasonic detectors. The ultrasonic detectors are particularly effective in locating large leaks when they are at or close to the tubesheet being surveyed. The method consists of scanning the suspected tubesheet area with an ultrasonic sensing atmospheric probe which has a peak sensitivity between 35 and 45 kHz. The probe detects the ultrasonic waves generated by the leaking gas turbulence. Its operating frequency range is that which experience has shown to result in the highest signal-to-background ratio around most industrial facilities. The sensitivity could not be accurately defined from the survey data. It appears to be in the gpm range for leaks located in the tube central sections and to be better than one tenth of a gpm for leaks located at or near the tubesheet (again considering condensers operated with low circulating water pressure).
- Hydrotest methods are used during complete plant shutdown by filling the condenser steam side with water. This is sometimes done with dyed water which allows for a precise identification of all significant leaks. This is often used as part of the normal condenser preventive maintenance program. The condenser must be capable of accepting the relatively large weight of water that is required.

Water Leakage Repair

Condenser water leaks almost always develop in or around the condenser tubes. On rare occasions, leakage can occur through the tubesheet to shell joint.

Tube leaks are usually repaired by inserting a plug in the opposite ends of the defective tube. Typical plugs are shown at the lower right in Figure 4-8. The plugging operation is straightforward and usually presents no problems.

However, condensers operated on highly corrosive waters should be repaired using only a plug material that has proved capable of withstanding the circulating water environment.

Another well-known tube leak repair method is the addition of sawdust or a cellulose-asbestos mixture. Its benefits are temporary and somewhat unpredictable. It was extensively used until environmental protection regulations banned its use for open-cycle circulating water systems. It is still in use in at least one cooling tower plant. Its possible effect on the towers could not be evaluated adequately, but appeared to be negligible.

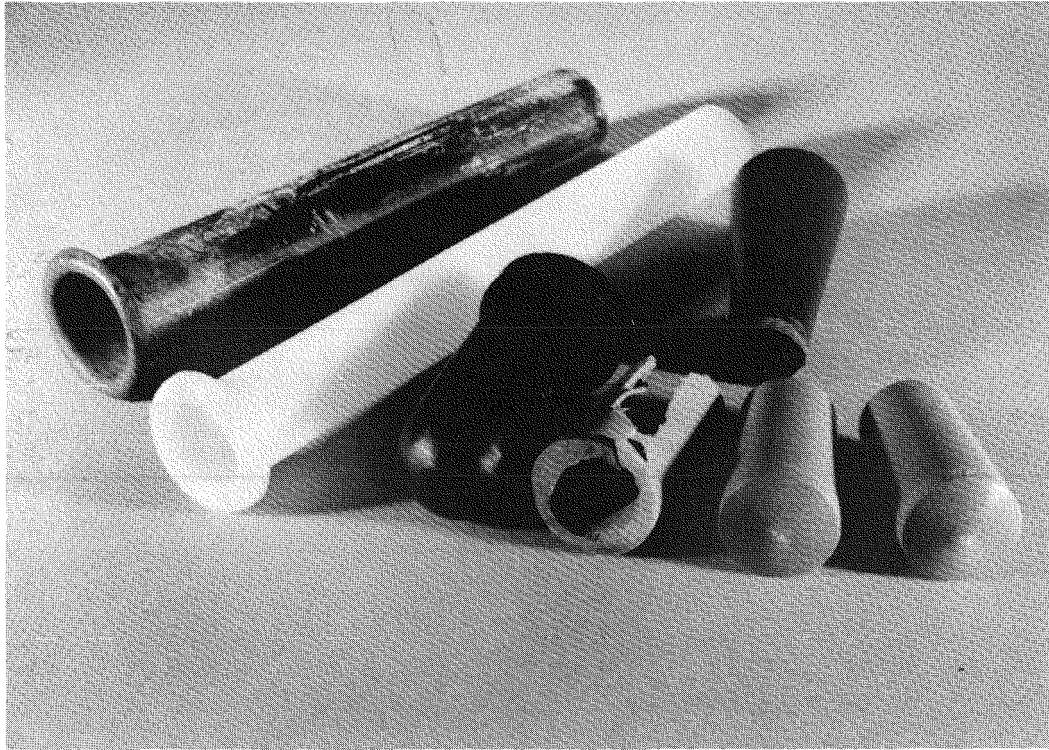


Figure 4-8. Typical Tube Inserts (Upper Left) and Plugs (Lower Right)

A third tube leak repair method is used to protect the tubes against localized inlet end erosion and/or corrosion. It consists of covering the tube 8 to 12 inches inward from the end with a coating such as coal tar epoxy or with a metal or plastic tube insert. (See Figure 4-8 and 4-9.) It can be used only to protect the tubes or to both protect and seal leaking tubes. It provides effective protection and can substantially increase tube service life.

In a few special cases, condensers may develop leaks through the tube-to-tube-sheet joint. Field surveys included two plants using rolled tube joints where this type of leak was found. In one plant, the joint leakage was traced back to poor workmanship during tube installation. In the other plant, the leakage developed after circulating water hammer had severely overloaded the tube joints and "pulled out" some of the tubes. In the first case, the leaks were repaired for the most part by rerolling. In the second case, they were repaired mostly by tube plugging.

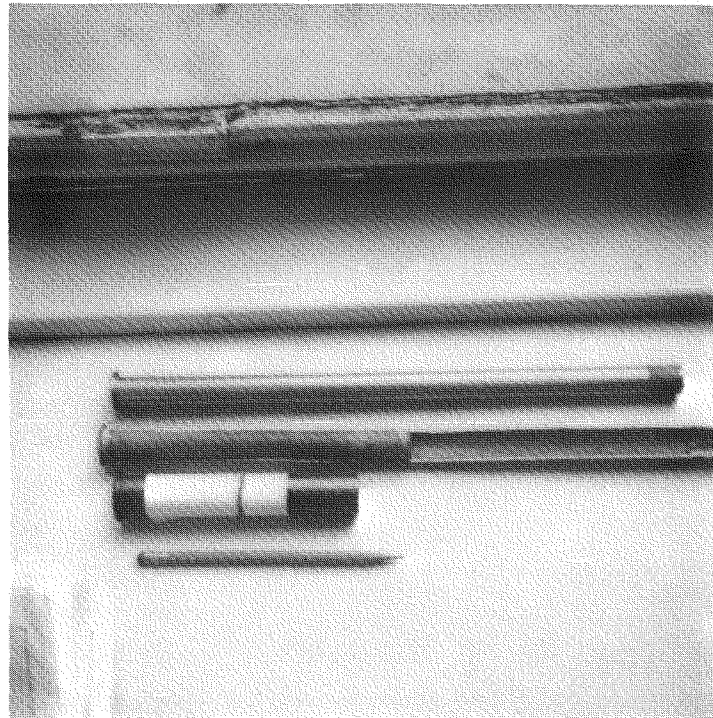
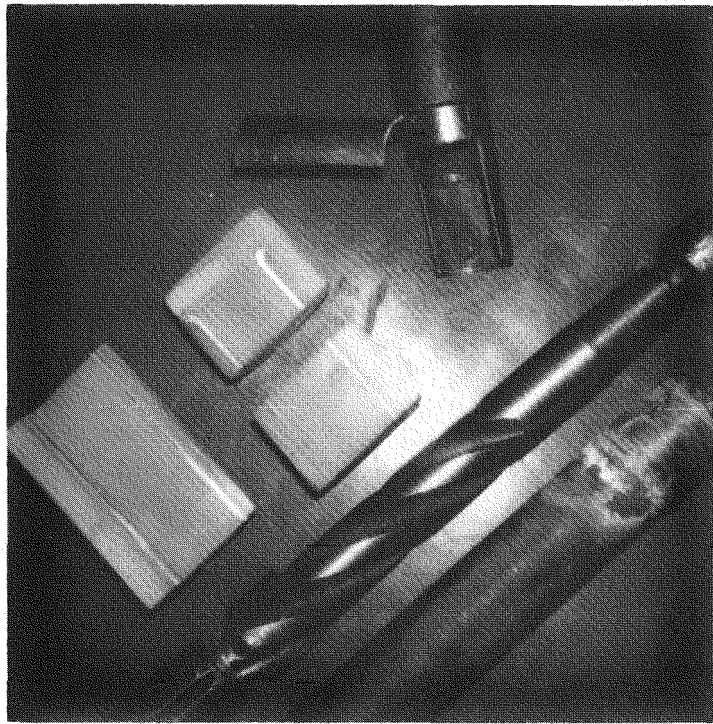


Figure 4-9. Typical Tube Insert Setup

When numerous tube failures have occurred over some part or the whole of a condenser's tube bundle, partial or complete tube replacement may be desirable.

A maintenance operation that is being used increasingly consists of testing the tubes nondestructively from the water side. The eddy current method has been used at several of the plants surveyed. This method can identify tubes that have experienced major degradation and should be plugged as early as practical. Also, the method may assist in defining the cause of the failures. Eddy current findings may be of great value in pointing out potential problems, in allowing for efficient preventive tube plugging, and in supplying data needed to forecast retubing requirements.

AIR INLEAKAGE

Modern power plants rely mainly on the condenser to collect noncondensable gases and to provide a source point for their continuous removal. In fossil and PWR plants, the noncondensable gases are mostly due to the leakage of air into components that are below atmospheric pressure. The cycle components are built and operated in such a way that they require very low oxygen levels on the steam side (usually in the 5 to 15 ppb range). Some plants rely entirely on the condenser for deaeration. Others include a feedwater deaerator that enables operation with relatively higher condensate oxygen.

In BWR plants, most of the noncondensable gases are caused by the radiolytic decomposition of water that takes place inside the nuclear reactor. Air inleakage is experienced just as in any other plant, but its relative effect on the cycle is normally quite small. BWR plants are also unique in the following respects: the noncondensable gases are radioactive and can be released to the atmosphere only after processing. Also, BWR cycle water chemistry specifications require oxygen concentrations to be kept fairly high (preferably between 50 and 100 ppb), and feedwater deaerators are never used.

In the following paragraphs the study findings of interest to air inleakage in fossil and PWR plants are reported first. In many cases these findings are also applicable to BWR plants. When required, additional information that applies specifically to BWRs follows.

Air Leakage Impact

The field survey findings suggest that the impact of air inleakage on fossil and PWR plants is sometimes underestimated. It was found that more than half of the plants surveyed pay little attention to air inleakage as long as the feedwater and condensate oxygen contents can be maintained within specifications during steady power operation. The findings also show that less than half of the plants monitor the inleakage flow rate systematically and with high accuracy.

A review of plant chemistry records shows that during startup and low load operation, many units had relatively high oxygen and corrosion product levels that could possibly contribute to steam generator fouling. This was informally evaluated by two large utilities that attempted to correlate the pressure drop buildup in fossil plant once-through boilers to the number of cold restarts. The evaluation showed that for the units evaluated, boiler fouling was mostly due to startups rather than long-term, relatively clean power operation.

The field survey also confirmed that copper alloy corrosion products are potentially detrimental to all types of steam generators (fossil fueled, PWRs, and BWRs). They may induce the following effects: 1) the alloy corrosion products themselves may adversely affect the boiler; 2) they may trap other water impurities, such as iron corrosion products, and combine with them to impact on the steam generator (heat transfer, pressure drop, and corrosion); and 3) they may hamper the steam generator cleaning operation. It is well known that copper alloy corrosion product release is strongly dependent upon cycle steam and water oxygen concentration. Also, it is dependent on the concentration of ammonia which is used for pH control in fossil-fueled and PWR plants. Air inleakage has therefore a special effect on plants that use large amounts of copper alloy heat transfer surfaces in their condenser and/or low pressure feedwater heaters. This impact is further evaluated in Section 5, Performance of Condenser Tube Alloys.

In BWR plants, the surveys show that air inleakage is relatively well monitored because of its impact on the off-gas processing system. During normal operation, the direct effect of air inleakage on the cycle is essentially negligible. This may be illustrated by considering that in a large BWR plant (rated at about 1100- to 1200-MWe), the condenser noncondensable radiolytic gas flow rate is in the range of 250 scfm. In the same plant, only 5 to 10 scfm is due to air inleakage.

Air Leakage Frequency, Size, and Duration

Air leakage occurs in a very different manner than does circulating water leakage. A plant can be made essentially watertight, but it cannot be fully protected against air inleakage. This is because of the many potential leak paths around the active components maintained under vacuum (mostly valve stems and pump shafts). As a result, plants always have some air inleakage which may be classified as normal. In well-built and operated plants, the normal leak rate is typically quite small. For example, the normal leak rate at a recently completed 1100-MWe nuclear plant was about 3 scfm. The surveys also show that many plants are continuously operated with air inleakage flow rates that are relatively much greater. For example, most of the 600- to 900-MWe fossil fueled units surveyed reported normal leak rates in the range of 15 to 30 scfm.

In addition, the following air leakage problems have been reported:

- During startup and low load operation, normal leak rates are increased, sometimes by as much as a factor of 2 to 3 because a greater part of the steam cycle is under vacuum.
- During periods between maintenance, the normal leak rates also increase gradually, as valve stems and pump shaft packings deteriorate because of wear or aging.
- Occasionally a component failure is experienced and a step increase in leak rate results. The surveys indicate that such failures are relatively rare. They occur no more than once a year at any one plant on the average. These failures sometimes result in a severe loss of condenser vacuum and thus force an immediate plant shutdown.

Air Leakage Detection

The most straightforward air inleakage monitoring method is the direct measurement of the flow rate of noncondensibles being removed from the condenser. In fossil fueled and PWR plants, this measurement can be performed directly at the outlet of the steam jet air ejector or vacuum pump. The measurement can be used directly for trend monitoring. It can also be readily converted into an absolute value by a temperature correction. In BWR plants, it is usually performed at the off-gas system outlet point and is a reliable monitoring parameter during steady power operation. However, the measurement is difficult to interpret during transients, such as startups, because the off-gas system front-end equipment is then operating at very low yet fast-changing flow rates.

The direct measurement monitoring method is not always relied upon in fossil and PWR plants. In those cases, the following two parameters may be monitored for detection of potential gross air inleakage.

- Condenser backpressure is measured and correlated to plant load and circulating water temperature. Abnormally high readings are corrected to account for the estimated tube fouling and interpreted in terms of potential condenser air binding. Wherever needed, a pressure-to-flow-rate correlation is made using the air removal system characteristics. The method is obviously rather complicated and relatively inaccurate, particularly because it relies in part on a tube fouling estimate. Also, the correlation is based on generally poorly shaped characteristics. It is used because it is based on the backpressure monitoring that any plant must perform to ensure good operating efficiency.
- The condensate oxygen concentration is also used as an air inleakage indicator, again mainly because it must be monitored to ensure satisfactory plant operation (in this case, corrosion protection). It is evaluated after correlation with plant load, circulating water temperature, and estimated tube fouling. Its interpretation, however, is probably even more uncertain than that of backpressure, mostly because it reflects only condenser air binding and thus is very sensitive to local gas absorption and desorption phenomena that take place below the air removal section. As it leaves this section, the condensate is first subcooled and thus reabsorbs noncondensibles (particularly during startup and low load operation). Further down, however, the condensate is reheated by rising steam that enters the tube bundle from below. Figure 4-10 shows that moderate condensate temperature changes (subcooling) can result in relatively large changes in oxygen concentration. As a result, it is generally very difficult to use the average condensate oxygen content as an indicator of air inleakage. However, the method is effective for detecting gross air inleakage through the condensate pump shaft packing.

Air Leakage Location and Repair

Air leaks may be located during plant shutdown by filling the condenser steam side with water--possibly dyed--and watching for potential outleakage around suspected trouble areas such as valve stems and pipe joints. The field surveys showed, however, that most air leaks are located with the condenser under vacuum by the use of one or more of the following methods:

- Large leak detection by listening
- Ultrasonic monitoring for medium to small leaks. Ultrasonic detectors are very sensitive in low background noise areas, and they were generally judged quite effective by all the plants surveyed that had some experience with them.

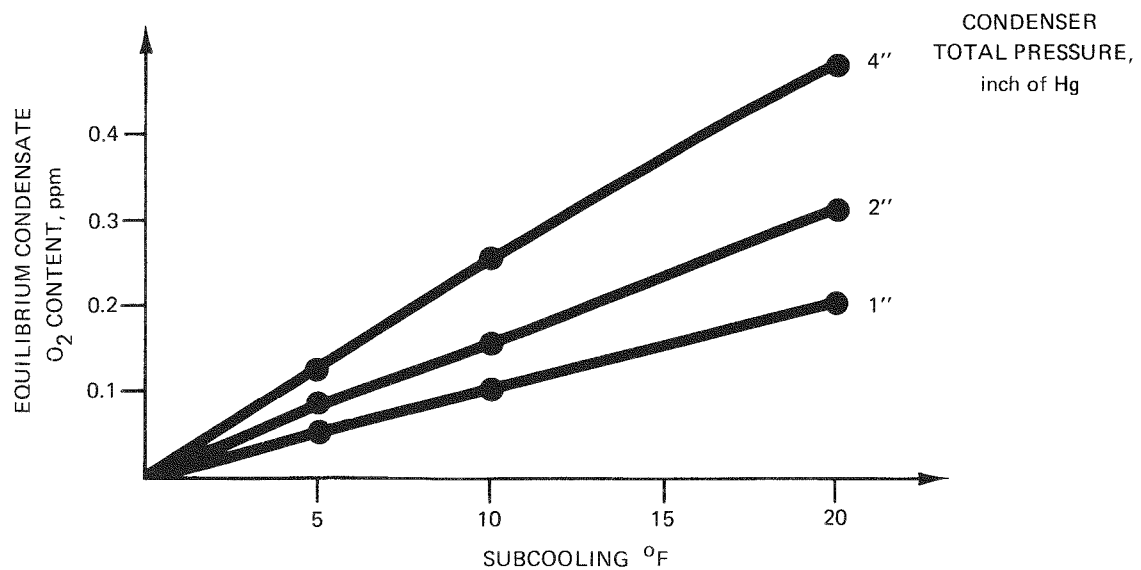
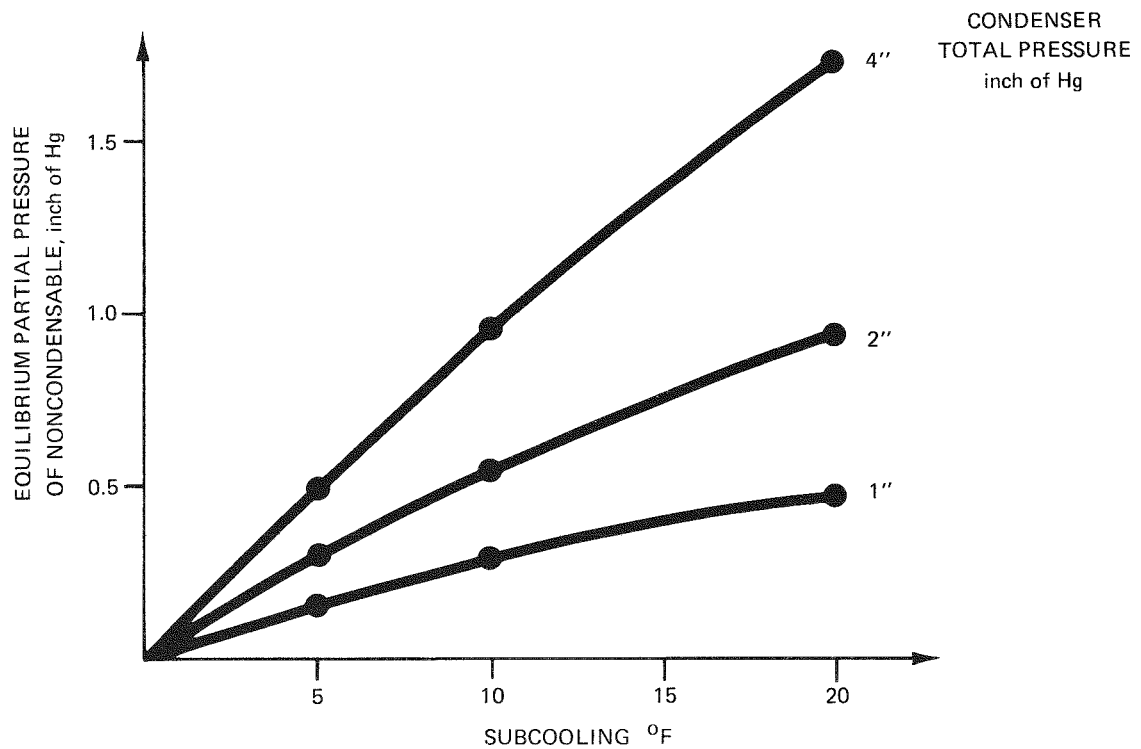


Figure 4-10. Equilibrium Noncondensable Partial Pressure and Equilibrium Condensate O₂ Content from Air Inleakage vs Condenser Total Pressure and Subcooling

- Freon inleakage detection by monitoring the plant off-gas with a halogen detector while dispersing freon in the vicinity of the suspected leak points. The freon method is not as simple as ultrasonic monitoring. However, some of the plants surveyed found it to be the only one that could locate small leaks in areas with high background noise.

Generally, the plants surveyed had only moderate success in permanently repairing air leaks with the condenser under vacuum. Most plants reported using such procedures as retightening packings or applying shellac around leaking valve stems. These procedures usually result at least in a temporary reduction of the leak. Permanent leak repair was reportedly performed mostly during plant shutdown.

OTHER OPERATION AND MAINTENANCE CONSIDERATIONS

Satisfactory condenser performance requires consideration of several important needs, limitations, and constraints not yet discussed. These additional considerations are of a more general nature than the specifications reviewed up to this point. For the most part, these considerations are function oriented and are, therefore, presented under the functional headings listed below:

- Startup
- On-line operation and maintenance
- Off-line maintenance.

Startup

The startup of a condenser and its related systems raises two major concerns:

- Circulating water flow startup without excessive load transients on the condenser and pump
- Prompt turbine cycle cleanup to bring the condensate and feed-water within operating water quality specifications

The following discussion considers the startup of plants using low-head circulating water systems and the startup of cooling tower plants. For both kinds of plants, the startup of the circulating water systems is reviewed first, followed by a review of the turbine cycle cleanup.

Low-Head Circulating Water System Plants. Plants that discharge waste heat to a lake, sea, or river generally use low head, mixed flow, high specific speed circulating water pumps of the wet pit vertical type. The condenser is generally located well above the heat sink water level and a syphon effect is used to reduce the pump head requirement. A typical circulating water system is illustrated in Figure 4-11 which shows a twin shell, four water box condenser. Pump characteristics are of the type illustrated in Figure 4-12. The circulating water system is sometimes started with valves wide open, with no special restriction or concern. Plants that require a long water supply line between pumps and condensers must limit the initial circulating water flow rate to protect against excessive water velocities and possible water hammer. Great care must be applied to ensure that the pump flow rate is not throttled down too far, as this could result in pump motor and thrust bearing loadings greater than twice normal levels and also far greater than design levels. The water boxes must be fully primed before the full flow can be established.

In some of the older, smaller units, these requirements are met in part by connecting the condenser outlet water box to its discharging pipe at a point higher than the tube bundle top tubes. The volume of air to be evacuated for the syphon to be established is then quite small. In newer--and larger--plants, a higher capacity water box air evacuation system is installed to allow for direct priming well within the startup period. Essentially all units surveyed as part of the present study fall in the second category and use a steam jet air eductor for priming purposes.

During plant startup, the condenser contributes to the steam cycle cleanup in the following ways: 1) it collects most of the cycle water and thus can be used as a point source for the cycle treatment used to reduce dissolved and suspended solid contents; and 2) it collects most of the cycle noncondensibles and allows for their removal by the off-gas system. The first function is straightforward and is performed readily, but the second one is difficult, particularly where the circulating water source is at very low temperature. Several of the plants surveyed have been unable to maintain condensate oxygen concentration within specifications during restarts. As indicated in the preceding Air Leakage Impact section, the study of the affected plant records suggests that the problem may be more significant than is commonly recognized. Excessive oxygen content appears to increase the amount of corrosion products that are carried into the steam generators during startup to the point that startups become the dominant source of external corrosion product input.

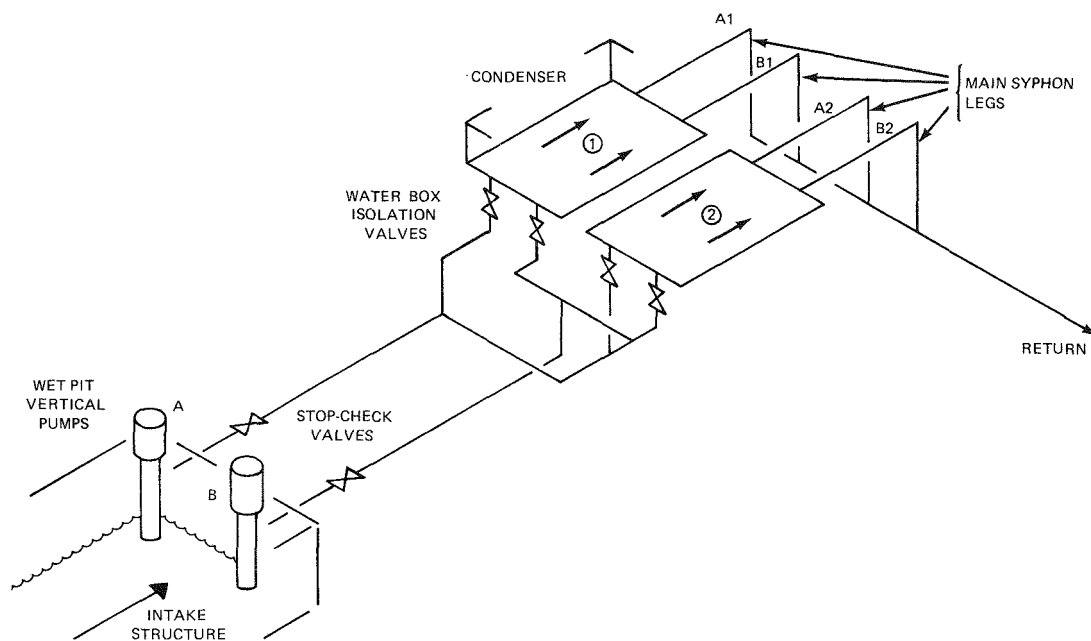


Figure 4-11. Typical Circulating Water System for Twin Shell Condenser with Open Cycle or Cooling Lake

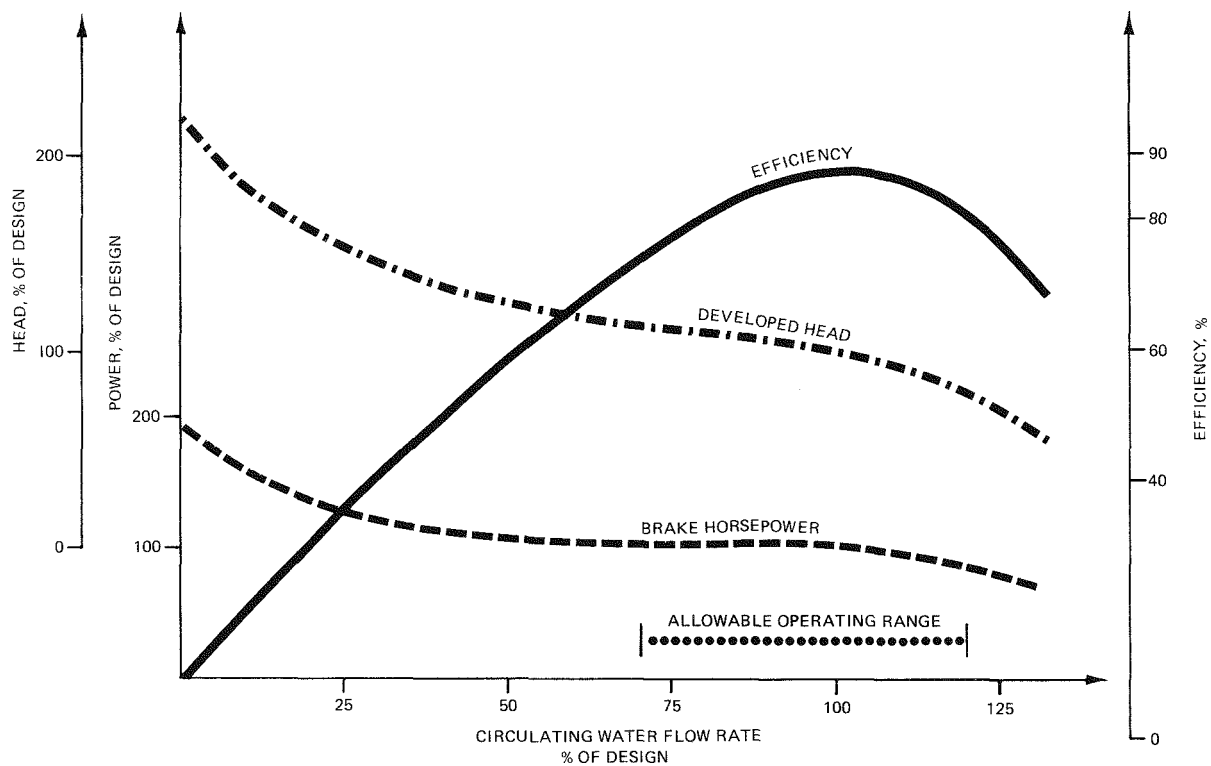


Figure 4-12. Typical Characteristics of Low Head Circulating Water Pumps

High-Head Circulating Water System Plants. Cooling tower plants generally use mixed flow, medium head, moderate specific speed circulating water pumps of the wet pit vertical type. The circulating water system is similar to that shown in Figure 4-11 except that it includes a vertical upward leg to the tower on the downstream side instead of a downward syphon leg. Also, cooling tower systems generally have a tower bypass line (at least part flow). They also include condenser downstream water box isolation valves to protect against downstream end positive pressure. The pump characteristics are of the type illustrated in Figure 4-13. Water boxes are maintained at a positive pressure during operation, and they are vented directly to the atmosphere.

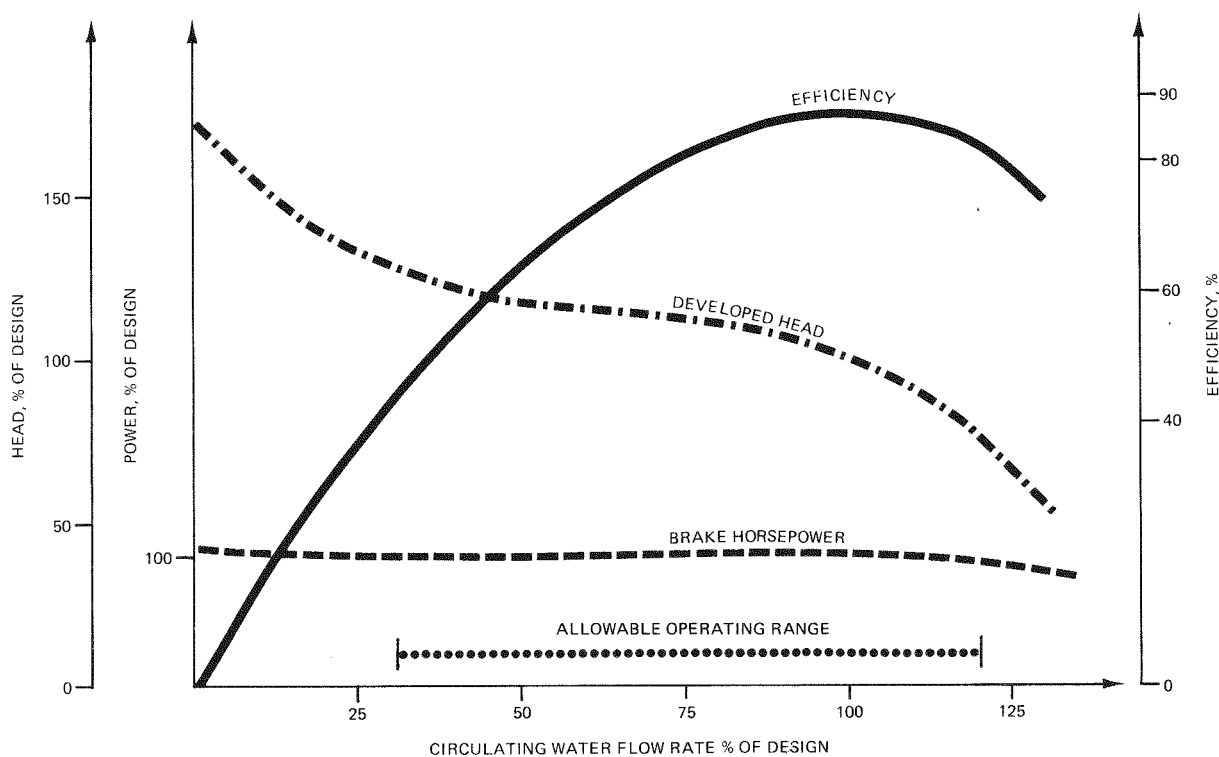


Figure 4-13. Typical Characteristics of Medium Head Circulating Water Pumps

The systems are normally started with the pump discharge valve throttled to about 30 to 50 percent capacity, with the condenser isolation valves wide open and with the tower bypass open. Bypass recirculation is maintained until the circulating water temperature is increased to the point where effective condensate deaeration is achieved.

Theoretically, the cooling tower plant circulating water system should be fairly easy to start. The survey confirms however, that a number of such systems have had the following startup problems:

- Water hammer, usually created by excessively fast or premature opening of the pump discharge valve
- Water box overpressurization caused by excessively fast closing of the condenser outlet valves

Both of these examples resulted in severe condenser damage.

On-Line Operation and Maintenance

The surveys show that condenser on-line operation and maintenance requirements vary over a very broad range, mostly as a function of circulating water composition. Most plants, however, perform on-line the functions listed below:

- Monitoring for
 - Water inleakage
 - Air inleakage
 - Heat transfer surface fouling
- Maintenance
 - Tube cleaning (either on-line or during part-load operation)
 - Water leak location and repair (during part-load operation)
 - Air leak location and repair

These functions have been reviewed in the preceding sections. The following paragraphs provide some additional information on tube cleaning.

On-line tube cleaning operations can be separated according to their objectives into the following two categories:

- Removal of the small deposits--or fouling--that gradually build up on the tube inner walls. Fouling may result in reduction of heat transfer coefficients and/or accelerated corrosion. The deposits may be caused by thermohydraulic and chemical phenomena or biological growth.
- Removal of the relatively large-sized foreign matter that is mechanically entrained in the condenser. This matter may result in complete or partial tube plugging and thus induce tube erosion, corrosion, and fouling.

Biological Growth Control by Chemical Addition. This is the primary tube cleaning method used at most of the plants surveyed (63 percent). It consists of adding sodium hypochlorite or chlorine gas to the inlet circulating water in such amounts that the outlet circulating water contains between 0.5 and 1 ppm of equivalent residual free chlorine (now limited to 0.2 ppm average--0.5 ppm maximum by 40 CFR 423). A few of the plants surveyed use or have used biodegradable biocides instead of chlorine.

Frequency, duration, and input dosage used vary greatly from plant to plant and from one season of the year to the other. For the most part, the chemical addition requirements are a function of the circulating water composition and temperature, of the condenser tube inherent toxicity, and of the effectiveness of the other tube-cleaning methods used.

Biological Growth Control by Thermal Treatment. This method is used at a number of seawater and brackish water-cooled plants. It consists of recirculating the outlet circulating water back to the intake as required to raise the circulating water system temperature to a level that is lethal for dominant marine organisms (usually about 120°F). It has been found to be effective even against large organisms such as clams and mussels which have a high tolerance for chemicals. This method has also been found to be generally more acceptable from an environmental viewpoint. The major drawback is the relatively high initial cost of the recirculating line or channel that is required.

Circulating Water Chemical Treatment. This method is used at a number of closed cycle freshwater-cooled plants that are operated on cooling towers or dedicated cooling lakes. It generally includes the addition of sulfuric acid

to prevent the precipitation of calcium carbonate. At plants that operate with a high calcium sulfate concentration product, a dispersing agent is employed. Two of the plants included in the field survey use such an agent and have reported it to be very beneficial in reducing deposit buildup.

On-line Mechanical Cleaning. This method is available at 12 percent of the plants surveyed. Two such cleaning systems have been developed, MAN and Amertap. No MAN system was installed in the plants surveyed. The surveys show that the Amertap system is very effective in removing all deposits, with the possible exception of the relatively hard calcium sulfate scale for which system effectiveness could not be adequately confirmed. The Amertap plants surveyed used relatively old system designs and were not equipped with the now frequently recommended debris filter. Many plants reported excessive ball losses apparently due to the buildup of debris in the outlet ball catcher and the spurious ball catcher flap opening caused by the resulting high pressure drop. Because of this, a number of plants have discontinued system operation. The problem could not be fully evaluated; however, it appeared that most ball losses would be eliminated by the upstream debris filter. A second problem reported with some of the systems is ball hide-out. For example, one of the plants surveyed reported short term hide-outs of up to several thousand balls. This second phenomenon is unusual, and a cure has apparently not yet been firmly established. It probably results, at least in part, from a combination of characteristics of the circulating water system (dead pockets - low velocity regions) with a mismatch of the ball weight to actual buoyancy. It appears that correction of the mismatch could reduce the problem to acceptable levels. Further data are needed, however, to confirm this hypothesis.

Reversing the Direction of Flow. Another on-line mechanical cleaning method consists of reversing the direction of flow across the condenser. It is used by approximately 3 percent of the plants included in the survey. It is aimed at backwashing the miscellaneous debris, grass, and leaves that accumulate on the inlet tubesheet. It is very effective at doing this, but its potential is limited and its initial cost is fairly high.

Off-line Maintenance

Condenser off-line maintenance requirements also vary over a broad range, mostly as a function of condenser status, tube material, and circulating water composition. Most plants systematically perform some of the following maintenance tasks:

- Inspect the condenser steam side once a year, paying particular attention to 1) indications of tube vibration and/or steam impingement, 2) the condition of insulation lagging, 3) the condition of drain or dump line inlet baffles, and 4) the presence of loose parts. At the same time, check the condenser and attachments for possible small air and water leaks; update the tube plugging records; confirm the suitability of the guard plugging schemes used, if any; inspect a sample of tubes on the water side for possible fouling, corrosion, and/or erosion; and check the condition of installed tube plugs and generally inspect the condenser and its related systems
- Supplement the above by performing eddy current examination of tubes, as described in the Water Leakage Repair section (see page 4-17)
- Protect the tube inlet end with coatings and/or inserts
- Maintain, as required, the tubesheet and water box wall coating and the cathodic protection electrodes and equipment (see Figure 4-14)
- Periodically perform manual tube cleaning to supplement, as required, the on-line cleaning method(s) and restore efficient heat transfer

Sixteen percent of the plants surveyed reported manual mechanical cleaning as their primary cleaning method. In most cases, cleaning is performed by inserting and shooting through each tube some kind of tight-fitted element such as an Amertap ball, a MAN-type of cylindrical brush, or a plastic, rubber, or sheet metal scraper (see Figure 4-15). Some plants reported using high pressure traveling water jets that are run along the whole length of the tubes, other plants perform a high velocity water flush, and a few plants used tube rodding.

Overall, manual mechanical-type cleaning methods were reported to be quite effective in restoring tube cleanliness. However, they are very time consuming and can be relied upon only when the tube fouling rate is fairly low. Generally, these methods are implemented during cold shutdowns, but some plants reported using them during off-peak hours, after partial load reduction and drainage of one condenser section.

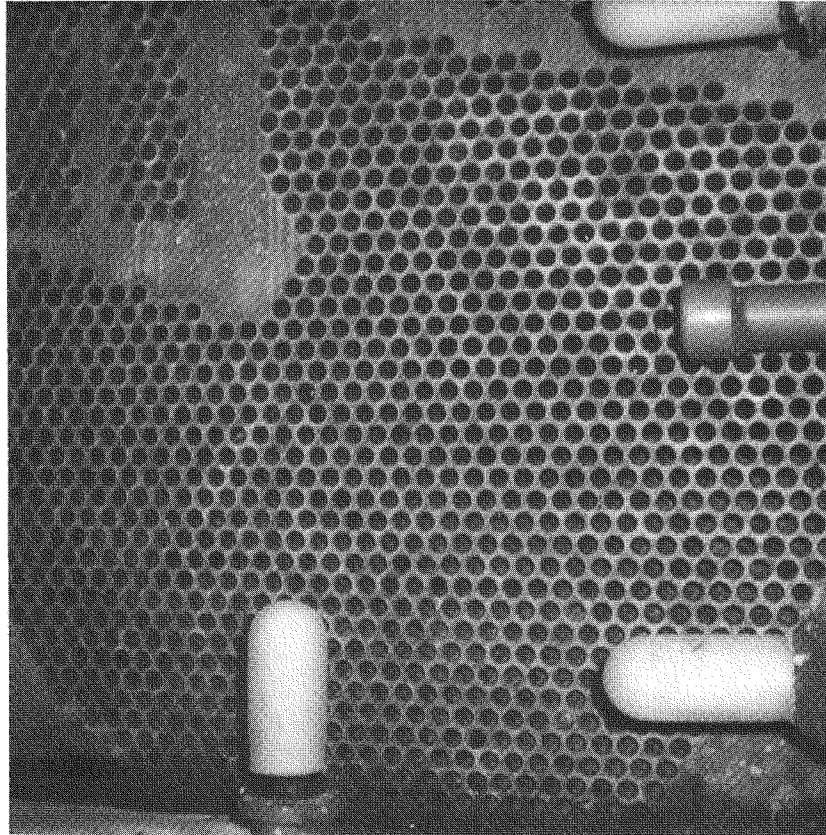


Figure 4-14. Typical Cathodic Protection Electrodes

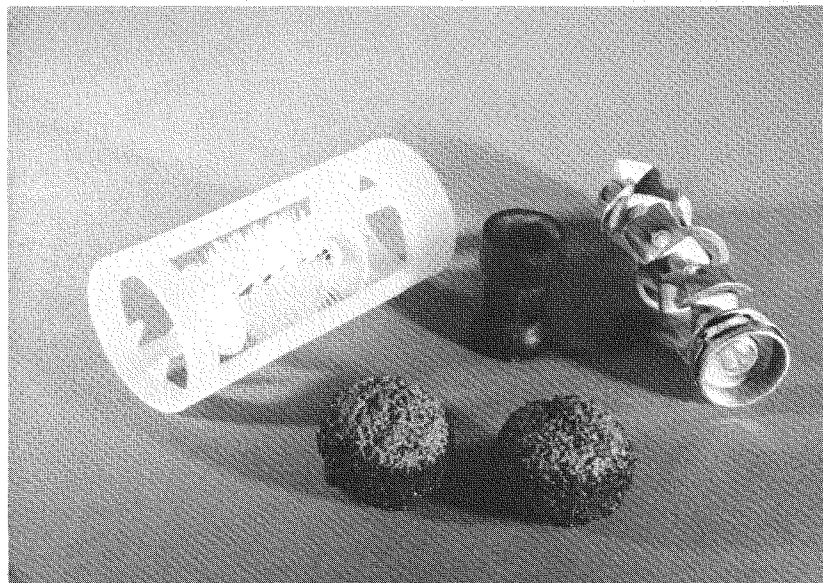


Figure 4-15. Typical Tube Cleaning Devices

Section 5

PERFORMANCE OF CONDENSER TUBE ALLOYS

INTRODUCTION

This Section contains the study results that are related to the performance of different condenser tube materials in various service environments. The classifications used to define the exposure conditions and the concepts used for presentation of the results are discussed. The survey findings are presented by tube alloy groups. A comparative summary of the performance of the commonly used alloys concludes the section.

Service Environment Classifications

Condenser tubes fail as the result of many different mechanisms. To evaluate their performance requires an orderly classification of the several service parameters so that comparisons can be made with equivalent data. A logical consideration of the various failure mechanisms leads to the following broad, categorical parameters which define the service environment.

- Tube material, dimensions, and physical properties
- Service sector within the condenser
- Steam-side environment
- Water-side environment
- Failure mode

These categories were used for the organization and evaluation of the survey data. Each is discussed in more detail below.

Tube Material, Dimensions, and Physical Properties. The material composition of the condenser tube is one of the major variables that affects its service performance. Accordingly, survey results are segregated by individual alloy. It was, however, necessary to lump all admiralty brasses into a single category because the admiralty alloy used was not known at several stations.

Tube diameter was found to have no discernible effect on performance, probably because of the narrow range of diameters in use. For a given alloy, the tube wall thickness is usually the same; e.g., all admiralty tubes surveyed were 18 BWG. For other alloys, wall thickness variations were not more than one gauge. While condenser tube lengths vary considerably, a preliminary analysis of the survey data indicated no correlation between tube length and failure incidence. Hence, tube dimensions are not of prime concern in the assessment of condenser tube failures.

The physical properties of the tubing material are important with regard to susceptibility to erosion and, to a degree, vibration. But because physical properties are specific for a given alloy and gauge, they need not be classified separately.

Service Sector in the Condenser. It is apparent that tubes in the three main service sectors of the condenser are subject to different failure mechanisms and failure rates. Tubes in the outer few rows (impingement section) are more susceptible to failure due to erosion by impinging steam and to severance or puncture by missiles or broken baffles than are the tubes in the main condensing section. Likewise, if the tubes in or immediately adjacent to the air removal section are of an ammonia-sensitive alloy, they can be expected to suffer a higher incidence of ammonia induced failures. This is because localized concentrations of ammonia can be orders of magnitude greater than the ammonia concentration in the bulk condensate stream.

In most condensers with admiralty tubes in the condensing section, tubes of a harder material such as stainless steel or copper-nickel are used in the impingement area. The incidence of ammonia attack may also be reduced by the use of stainless steel or copper-nickel in the air removal section.

Obviously, in a condenser containing tubes of more than one material, all tubes cannot be lumped together for failure-rate evaluation. It is also desirable to segregate the three service areas of the condenser if valid comparisons are to be made. Therefore, all condensers surveyed were subdivided into several "tubesets." A tubeset was defined as a group of tubes

of the same material, service sector, and age, for which failure rate information was available. The following tubeset designations were used:

A = air removal section

I = impingement section

C = main condensing section

O = all tubes in shell (must be of same material) equivalent to A + I + C for shell and used only when individual data were not available

B = complete bundle within shell (same qualifications as in O)

X = C + I when of same material and individual data not available

Y = I + A when of same material and individual data not available

Z = C + A when of same material and individual data not available

S = complete shell, combination of subsections for which individual data were available, may contain more than one material (these are repeat data and were excluded from most calculations)

In order to simplify the manipulation of the data and to give the largest possible data base, the categories that represent primarily condensing section tubes were combined:

M (main body) = C + O + B + X + Z

Both the individual and combined designations are tabulated in the Field Survey Matrix.

The tubeset concept was applied both to the existing and the replaced sets of tubes.

For example, a single condenser with two shells, each containing two bundles and having a separate air removal section in each bundle, would be divided into twelve tubesets. The tubesets would consist of the air removal, impingement, and condensing sections for each of the four bundles. On the other hand, if tabular data were available which listed only the total number of plugs in each bundle and no plug location drawing was available, then the condenser could be subdivided only into four-bundle tubesets -- provided all the tubes were of the same material. If the condenser had been retubed, then whenever possible, data were obtained for the replaced tubesets.

Steam-Side Environment. The steam-side environment can be responsible for tube failures from several mechanisms. Mechanical failures due to missiles, broken baffles, etc, occur on the steam side only. Other failures are caused by steam or water droplet impingement/erosion. To some degree, failures due to tube vibration relate to steam-side operating conditions. Most steam-side failures from electrochemical corrosion are induced by localized high concentrations of ammonia. Accordingly, the field survey sought all available information relevant to the steam-side environment. This included data on turbine cycle chemistry procedures such as chemicals fed, dosage, control methods and criteria, as well as analytical results both present and over the lifetime of the tubeset.

Water-Side Environment. The water-side environment is the most important parameter relative to tube failure frequency. While the chemistry and biology of the circulating water apparently are responsible for most water-side failures, other factors are also significant. Cavitation/erosion due to air release causes many tube failures as does erosion caused by high velocities in regions of partial tube blockage. Accordingly, data were sought not only on the chemical, physical, and biological properties of the circulating water, but also on water box configuration and the hydraulics of the circulating water system.

The cooling water at each station was classified into one of the following nine categories:

- R = River
- L = Lake
- M = Polluted freshwater
- T = Cooling tower
- S = Recycled spray pond or canal with concentrating mechanism
- B = Brackish -- variable from fresh to salty
- K = Polluted brackish
- C = Clean seawater
- P = Polluted seawater

These classifications are given in column 14 of the Field Survey Matrix. Because the various polluted categories were based primarily on the subjective opinion of station personnel rather than analytical data, and to facilitate

data manipulation with the largest possible arrays, the above categories were subsumed as follows:

<u>Water Type</u>	<u>Designation</u>	<u>Original Categories Included</u>
Fresh	F	R, L, M
Ocean	O	B, K, C, P
Concentrated	J	T, S

The combined water categories are tabulated in column 171 of the Field Survey Matrix.

The distribution of tubesets by tube alloy and cooling water category is shown in Table 5-1.

Table 5-1

DISTRIBUTION OF TUBESETS BY
MATERIAL AND WATER TYPE

ALLOY	TUBESETS IN FRESHWATER		TUBESETS IN TOWER WATER		TUBESETS IN OCEAN WATER		TOTAL	
	NO.	%	NO.	%	NO.	%	NO.	%
Admiralty Brass	134	45	18	31	1	<1	153	26
90-10 Cu-Ni	20	7	6	11	58	26	84	15
70-30 Cu-Ni	6	2	12	21	57	25	75	13
Cu-Ni (specific type unknown)	4	1	0	0	0	0	4	<1
Aluminum Brass	0	0	0	0	52	23	52	9
Aluminum Bronze	0	0	0	0	12	5	12	2
Type 304 Stainless Steel	117	39	21	37	0	0	138	24
Type 316 Stainless Steel	8	3	0	0	23	10	31	5
Titanium	8	3	0	0	23	10	31	5
Total	297	100	57	100	226	100	580	100

Failure Mode. From the onset of the study it was evident that identification of the causative failure mechanism would be possible only in rare instances. Often such determination cannot be made until after the failed tube is removed and submitted to comprehensive analysis and, on occasion, not even then. Nonetheless it was desirable to classify failure causes in the most practical manner

based on the data that could be gathered during the relatively brief field surveys. Helpful information would be gained if the reason for plugging the tubes could be placed in the following categories:

1. Mechanical failures including missiles, vibration, severance, etc.
2. Failures originating on the steam side for any reason other than mechanical.
3. Failures originating on the water side for any reason whatsoever.
4. Failures around the tube-to-tubesheet joints.
5. Tubes plugged to guard against anticipated early failure. At many plants tubes adjacent to failed tubes will be plugged because their imminent failure is anticipated.
6. Total failures for all reasons where any tube plugged was considered to have "failed."

Accurate information on *Total Failures* was obtained at all surveyed stations. In most cases the location of the plugs was accurately known as was the date when the plugs were installed. Information that allowed distribution of the plugs into the other five failure mode categories was available far less often than expected.

Failures classified into categories 1, 4, and 5 are virtually independent of the tube material. Failures classified into categories 2 and 3 are usually a function of the specific tube alloy. The 6th category -- total tubes plugged -- is obviously a mixed grouping which does not allow ready interpretation of failure mode or the location of the failure within the tube or the tube within the tubeset. However, it is the only category for which data were always available at the surveyed stations and, of necessity, most of the results presented in this section are based on the *Total Plugged* category. Actually, performance results calculated from the *Total Plugged* category are a practical measure of condenser tube serviceability because condenser performance and maintenance costs are affected by the number of tubes plugged, not by the reason for the plugging.

Performance Rating Factor

Quantitative analysis of the performance of condenser tubes of different alloys in various environments requires the development of a suitable mathematical expression for the rate of failure. Yet, because of the many different failure modes, a single expression that precisely describes the total failures versus time curve is not possible. The number of tubes failed as a function of time

can be expected to increase exponentially for certain classic corrosion modes of failure. But failures due to missiles, broken baffles, etc, are independent of time. Over the years, the power industry has developed a number of methods for analyzing and interpreting failure rates.

After a review of the problem it was decided that the survey results would be quantified by the use of the Newton and Birkett (46) formula:

$$FR = \frac{F/N \times 100}{\text{Service Hours} \times 10^{-4}}$$

where FR = Failure rate, percent of tubes plugged per 10,000 hours of operation

F = Number of tubes failed

N = Number of tubes in tubeset.

This expression yields the linear or average failure rate during the time interval from the first service of the tubeset to the time of calculation. The value calculated for any single time, in most instances, does not describe the true shape of the F vs t curve over the selected time interval. The failure rate $\Delta F / \Delta t$ is numerically equal to dF / dt only when the F vs t curve is linear. If sufficient tubeset data are available to enable calculation of FR at frequent intervals through the service life of the tubeset, an accurate and adequate description of the failure curve results. Unfortunately, ample data were not always available for the surveyed tubesets.

The calculation sheet used to tabulate the several failure rates is shown in Table 5-2. To the extent the collected data allowed, the failure rates were calculated for each failure mode (FRM, FRS, FRW, FRJ, FRG, and FR) at accumulated service hour periods of 10,000, 20,000, 40,000, 60,000, 90,000, 120,000, and 180,000, as appropriate, up to the survey date or for the end of service of the replaced tubesets. For relatively new tubesets (less than 20,000 hours in service), the time periods used were 1/10 of those indicated. The distribution of tubesets for which the total failure rate (FR) could be calculated is shown in Table 5-3 by tube material, condenser service sector, and cooling water type. The distribution of the total number of condenser tubes and the condensing service area is shown by tube alloy and cooling water category in Table 5-4.

Table 5-2

EPRI CONDENSER LEAKAGE STUDY - JOB 11540-001
TUBE SET FAILURE RATE CALCULATION SHEET

STATION _____ UNIT _____ SHELL _____ BUNDLE _____ SET _____
 TUBE SET NO. _____ TUBE SET DESCRIPTION _____
 TUBE MATERIAL _____ O.D. _____ " GAGE _____ BWG LENGTH _____
 TUBE MANUFACTURER _____ NO. OF TUBES IN TUBESET _____
 INITIAL SERVICE DATE ____ / ____ / ____ TOTAL TUBE SET LIFE _____
 PRESENT TUBE SET? _____

ACTUAL OPERATING HOURS								
DATE	/ /	/ /	/ /	/ /	/ /	/ /	/ /	/ /
CAUSE OF FAILURES	STANDARD OPERATING INTERVALS (X10 ⁻³ HRS)							TO DATE OR END OF LIFE
	10	20	40	60	90	120	180	
MECHANICAL (FRM)								
PLUGS								
FR								
STEAMSIDE (FRS)								
PLUGS								
FR								
WATERSIDE (FRW)								
PLUGS								
FR								
JOINT (FRJ)								
PLUGS								
FR								
GUARD (FRG)								
PLUGS								
FR								
TOTAL (FR)								
PLUGS								
FR								

NOTES:

$$FR = \frac{\text{PLUGS}}{\text{NO. OF TUBES} \times 10^6} \times \text{OPERATING HOURS}$$

Table 5-3

DISTRIBUTION OF TUBESETS WITH KNOWN FAILURE RATES
BY MATERIAL, CONDENSER SERVICE, AND WATER TYPE

MATERIAL	TUBESETS IN FRESH WATER				TUBESETS IN TOWER WATER				TUBESETS IN OCEAN WATER					TOTAL				
	M	A	I	TOTAL NO. %	M	A	I	TOTAL NO. %	M	A	I	Y	TOTAL NO. %	M	A	I	Y	ALL %
Admiralty	66	34	2	102 44	16	0	0	16 36	1	0	0	0	1 <1	83	34	2	0	119 25
90-10 CuNi	16	1	0	17 7	0	4	0	4 9	55	1	0	0	56 29	71	6	0	0	77 16
70-30 CuNi	0	0	0	0 0	2	10	0	12 27	6	45	0	2	53 28	8	55	0	2	65 14
Specific CuNi, Type Unknown	0	0	4	4 2	0	0	0	0 0	0	0	0	0	0 0	0	0	4	0	4 21
Aluminum Brass	0	0	0	0 0	0	0	0	0 0	35	2	0	0	37 19	35	2	0	0	37 8
Aluminum Bronze	0	0	0	0 0	0	0	0	0 0	12	0	0	0	12 6	12	0	0	0	12 3
Type 304 Stainless Steel	26	42	27	95 41	9	2	2	13 29	0	0	0	0	0 0	35	44	29	0	108 23
Type 316 Stainless Steel	0	4	4	8 3	0	0	0	0 0	2	3	4	0	9 5	2	7	8	0	17 4
Titanium Total	0	4	4	8 3	0	0	0	0 0	21	2	0	0	23 12	21	6	4	0	31 7
TOTAL	108	85	41	234	27	16	2	45	132	53	4	2	191	267	154	47	2	470

M - Main Body
A - Air Removal Section
I - Impingement
Y - I + A

Table 5-4

DISTRIBUTION OF NUMBER OF TUBES
AND CONDENSING SURFACE AREA
BY MATERIAL AND WATER TYPE

ALLOY	FRESH WATER		TOWER WATER		OCEAN WATER		PERCENT OF TOTAL	
	NO. TUBES	SURFACE AREA $\times 10^3$ FT ²	NO. TUBES	SURFACE AREA $\times 10^3$ FT ²	NO. TUBES	SURFACE AREA $\times 10^3$ FT ²	NUMBER TUBES	SURFACE AREA
Admiralty	499,534	4,779	144,632	1,399	5,340	43	29	26
90-10 Cu-Ni	74,540	864	2,008	20	422,635	4,601	22	24
70-30 Cu-Ni	1,208	10	23,404	238	79,484	882	3	5
Cu-Ni (Specific type unknown)	512	4	0	0	0	0	<1	<1
Aluminum Brass	0	0	0	0	333,203	3,345	15	14
Aluminum Bronze	0	0	0	0	88,550	814	4	4
Type 304 Stainless Steel	230,160	2,151	174,968	1,781	0	0	18	17
Type 316 Stainless Steel	1,720	16	0	0	37,605	469	2	3
Titanium	1,284	14	0	0	163,400	1,690	7	7
Misc	7,212	69	0	0	0	0	<1	<1
Total	816,170	7,907	345,012	3,438	1,130,217	11,844	100	100

Probability Calculation

A practical and useful comparison of failure rates for different materials and service conditions can be obtained by calculating the probability that a given failure rate will be attained. This was done whenever the field survey yielded sufficient data. The probability was calculated after Newton and Birkett (46) as shown in the following example:

The data bank for admiralty tubes in main body service in fresh water consisted of 66 tubesets for which the total terminal failure rate could be calculated. The calculated failure rates (FR) were arrayed in numerical order and ranged from 0.000 to 2.565. The median FR was 0.031, the arithmetic average of the

thirty-third and thirty-fourth value in the array. Fifty percent of the tube-sets had a failure rate less than 0.031; hence there is a 50-percent probability that the FR will not exceed 0.031. In 6 of the 66 cases, the failure rate exceeded 0.333; hence the probability of an FR of 0.333 or less was 91 percent. Likewise, 58 of the 66 tubesets had an FR of 0.222 or less; hence, the probability is 88 percent that an FR less than 0.222 will be attained.

The validity of the calculated probability values is clearly dependent on the number of tubesets included in the data bank and how representative they are.

The calculated probabilities can be used for approximate estimates of the anticipated service life of a tubeset. If a tubeset served 7,500 hours a year for 40 years and at that time had 10 percent of the tubes plugged, the failure rate would be 0.333. Based on the data collected in this survey (given in the example above) for admiralty tubes in main-body service with fresh cooling water, there is a 91 percent probability that the failure rate will be 0.333 or less. This corresponds to 40 years of service with not more than 10 percent of the tubes plugged. Also, the probability is 88 percent that admiralty tubes in main body service in fresh water will have a failure rate less than 0.222, which corresponds to 30 years of service with not more than 5 percent of the tubes plugged.

Obviously, caution must be exercised in the application of this estimated service life especially for data arrays that contain relatively few, or relatively young, tubesets. Inherent in this calculation procedure is the assumption that the attained failure rate is independent of the age of the tubeset. This assumption is verified for the data collected in this survey which show no correlation between the total failure rate and the age of the tubeset. Whether this assumption will be valid over 40 years for titanium, for example, where the oldest tubeset has been in service only 6 years cannot be affirmed from the data now available.

Presentation of Results

Most of the study results are presented in plots of Failure Rate versus Probability calculated as described above. Most of the graphs are in two sections. The upper section is a graphic nomograph that enables rapid determination of the failure rate that corresponds to a given service life in hours (or years at 7,500 hours per year), and a given percentage of plugged

tubes. The curve plotted in the lower section shows the probability (as calculated from the particular data base) that the corresponding failure rate will not be exceeded. Within the limitations described, these plots are believed to be valid and useful presentations of the historical data on condenser tube performance as collected by this survey. While individual exceptions to the trends shown must be expected, in view of the breadth and depth of the survey sample as described in Section 3, the trends should be typical of industry-wide experience.

COPPER-BASE ALLOYS

Copper-base alloys have historically been used for condenser tubing materials because of their good heat transfer coefficients, anti-biofouling characteristics, and relatively good corrosion resistance. Table 5-1 shows that of the total 580 tubesets surveyed, 380 or 66 percent were copper-base alloys. Table 5-4 shows that 73 percent of the tubes and 73 percent of the total condensing surface area in the surveyed plants were fabricated from copper-base alloys. Table 5-5 lists the copper-base alloys found in the surveyed condensers, the copper alloy number (CA), the designation used in this study, and the chemical composition of each alloy. Note that no distinction is made between copper alloys 443, 444, and 445, the admiralty brasses. The plants surveyed often did not know which of these alloys was in service. Furthermore, the performance of each is similar.

Historically, admiralty brass condenser tubing has been used for freshwater service while the copper-nickels, aluminum brass, and aluminum bronze are used predominantly in seawater cooled plants. This trend can be seen in Table 5-4. In the past decade, the copper-nickels, and especially 90-10 Cu-Ni, have been specified more often as tube material for seawater cooled plants. The copper-nickels, i.e., 70-30 Cu-Ni and 90-10 Cu-Ni, have lower corrosion rates in seawater and are more resistant to ammonia attack than the other copper-base alloys. All of the copper alloys are highly susceptible to erosion-corrosion. Erosion-corrosion includes degradation caused by air release and locally turbulent, high velocity water.

A chromium bearing copper-nickel alloy, IN838 (CA722), has been developed which reportedly has significantly increased resistance to erosion-corrosion in seawater. However, no condensers have yet been tubed with CA722 and thus no operating data are available.

Table 5-5
COPPER-BASE ALLOYS
CHEMICAL COMPOSITION AND DESIGNATION

MATERIAL (COMMON NAME)	STUDY DESIG- NATION	COPPER ALLOY NUMBER	COPPER	TIN	ALU- MINUM	NICKEL	LEAD, MAX.	IRON	ZINC	MANGA- NESE	ARSENIC	ANTI- MONY	PHOS- PHORUS
Admiralty Brass	AD	443	70-73	0.9- 1.2	-	-	0.07	0.6 max	R*	-	0.02- 0.10	-	-
Admiralty Brass	AD	444	70-73	0.9- 1.2	-	-	0.07	0.6 max	R*	-	-	0.02- 0.10	-
Admiralty Brass	AD	445	70-73	0.9- 1.2	-	-	0.07	0.6 max	R*	-	-	-	0.02- 0.10
90-10 Copper-Nickel	CL	706	86.5 min	-	-	9.0 11.0	0.05	1.0- 1.8	1.0 max	1.0 max	-	-	-
70-30 Copper-Nickel	CN	715	65.0 min	-	-	29.0- 33.0	0.05	0.40- 0.70	1.0 max	1.0 max	-	-	-
Aluminum Brass	BA	687	76.0 79.0	-	1.8- 2.5	-	0.07	0.06 max	R*	-	0.02- 0.10	-	-
Aluminum Bronze	AB	608	93.0 min	-	5.0- 6.5	-	0.10	0.10 max	-	-	0.02- 0.35	-	-

*R = Remainder

Admiralty Brass, AD; CA 443, 444, 445

Freshwater Service. Admiralty brass was the most common tube alloy for freshwater service in the surveyed condensers. It accounted for 44 percent or 134 of the tubesets, 62 percent of the tubes, and 61 percent of total condensing area. Figure 5-1 indicates that the 66 admiralty brass tubesets in main-body service have an excellent performance record in fresh cooling waters. There appears to be a greater than 90-percent probability that admiralty tubes in main-body service will last 40 years with less than 10 percent of the tubes plugged. There also appears to be at least 90-percent probability that admiralty brass will provide 40 years service with only 5 percent of the tubes plugged. The median failure rate was 0.031. Only two of the 66 admiralty tubesets in this service had been replaced.

Contributing failure mechanisms were given for many of the tubesets. Some tubesets had more than one failure mechanism given; others had none. In order to gain some insight on the impact of a particular mechanism, the number of times each failure mechanism was cited was tabulated. Table 5-6 indicates that waterside corrosion accounts for most of the failure mechanisms attributed to admiralty brass in freshwater. Most of these failures are in the "general corrosion -- specific type unknown" or "stress corrosion cracking" categories.

Table 5-6

CONTRIBUTING FAILURE MECHANISMS
FOR ADMIRALTY BRASS IN FRESH WATER

Cause	AIR REMOVAL TUBESETS		ALL TUBESETS	
	No. Of Times Cited	Percent	No. of Times Cited	Percent
General corrosion or specific type unknown	26	74	36	38
Stress corrosion cracking	8	23	14	15
Pitting				
Erosion-corrosion	1	3	11	11
			5	5
Falling objects			2	2
Tube joints			4	4
Steam erosion			10	10
Vibration			7	7
Mechanical			7	7
TOTAL	35	100	96	99

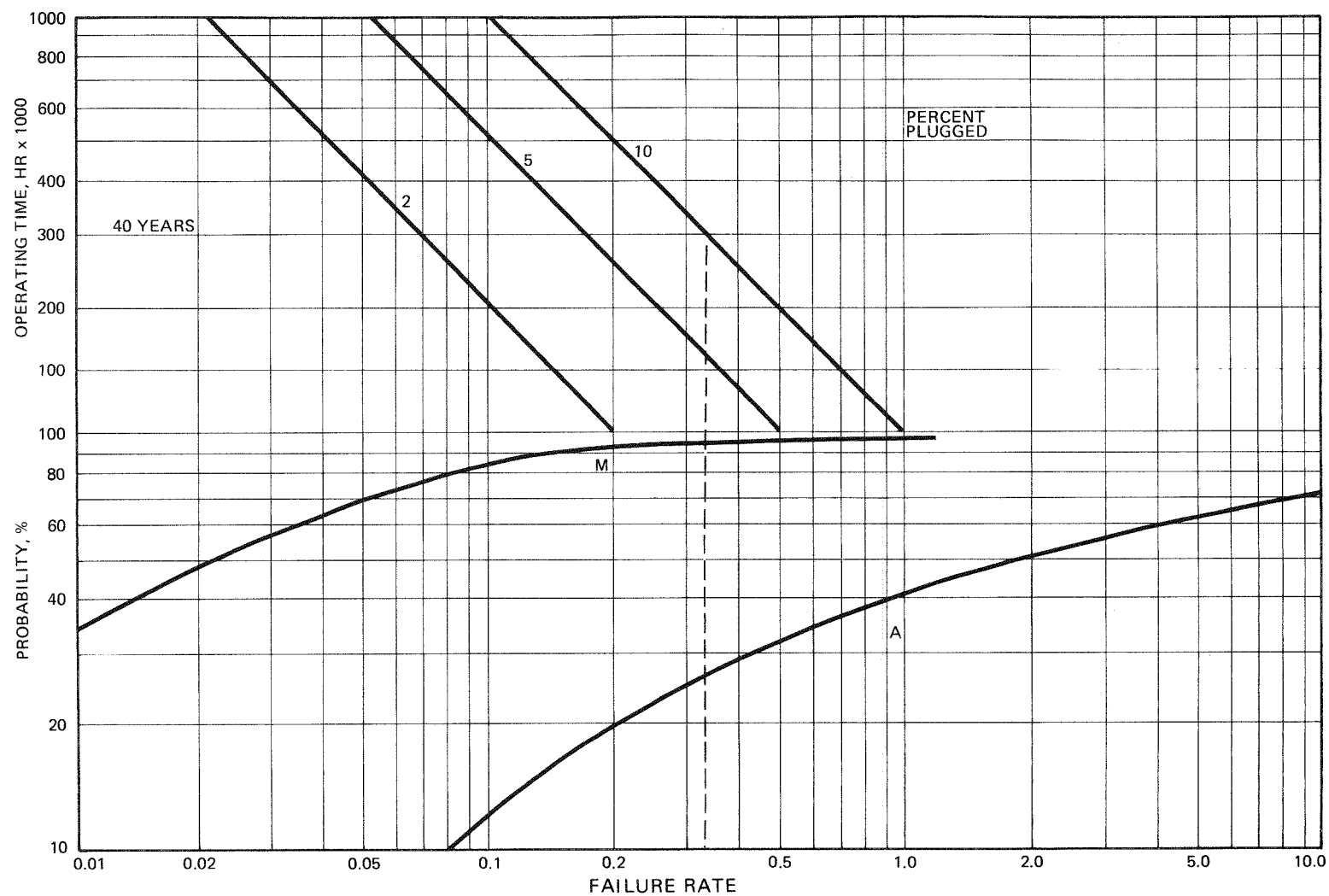


Figure 5-1. Failure Rate vs Probability Curves for Admiralty Brass in Freshwater Service. Curves for Main-Body Service (M) (66 Tubesets) and the Air Removal Section (A) (34 Tubesets) are Shown.

Cooling Tower Service. Failure rate data were available for only sixteen tube-sets in cooling tower service and one tubeset in ocean water service. Since the data base was so small, only limited performance evaluations were attempted. The observed median failure rate was 0.135, over 4 times greater than for tube-sets in freshwater service.

Effect of Ammonia. Admiralty brass is highly susceptible to ammonia attack, and also to ammonia-induced stress corrosion cracking. High concentrations of ammonia can exist in the air removal sections of surface condensers. Wilson (32), for example, has estimated the ammonia level in the air removal section of a condenser to be as high as 125 ppm even when there is only 0.2 ppm in the hotwell. Andres noted concentrations of approximately 400 ppm in condensate sampled adjacent to the tubesheet in the air removal zone with ammonia feed-water treatment controlled at 0.2 ppm.* He stated that adding morpholine to the feedwater will increase the ammonia concentration to 1000 ppm (due to decomposition) at the same location. Coit, et al. gave an example where a utility collected condensate from tubes in the air removal section and found it to contain as high as 500 ppm ammonia (189). Fink and Boyd reported the same value.** Aoyama et al. (185) observed 45 to 2700 ppm ammonia in the steam and 4 to 258 ppm ammonia in the condensate. In view of the above, admiralty brass in the air removal zone would be expected to perform poorly. This was found to be the case in the surveyed condensers and is best shown in Figure 5-1. Using the 10-percent of tubes plugged criterion, it can be seen that there is less than 30-percent probability that admiralty brass in the air removal section will attain a 40-year life.

Effect of Hotwell Ammonia Concentration and Shrouding. Shrouded air removal sections may contain higher concentrations of ammonia than unshrouded ones. Therefore, an attempt was made to correlate failure rate and hotwell ammonia concentration for shrouded and unshrouded sections. The correlation attempt was performed for all admiralty tube-sets and for those used only in air removal service. There appeared to be no correlation between hotwell ammonia concentration and failure rate.

*Andres, R.F., Proceedings of the 18th Water Conference, 1957, Discussion p. 102.

**Fink, F.W. and Boyd, W.K., Topical Report on "Corrosion Problems in Power Plant Steam Condensers," to the Copper Development Association, May 1971, Battelle Columbus Laboratories.

In order to determine the effect of shrouding, the ratio of shrouded to unshrouded tubesets (Rs) was calculated for several failure rate increments. For all the tubesets studies this ratio was 1.32. Except for the very low failures rates and very high failure rates, i.e., those less than 0.01 and greater than 10.0, respectively, Rs increased as the failure rate increased as shown in Table 5-7.

Table 5-7

RELATIONSHIP BETWEEN THE SHROUDED-
UNSHROUDED RATIO, Rs, AND FAILURE RATE

	FAILURE RATE INCREMENTS				
	<0.01	0.01 to 0.1	0.1 to 1.0	1.0 to 10.0	>10.0
RS	3.33	0.50	2.29	3.25	1.17
Number of Tubesets	13	34	21	17	13

It was also noted that Rs equaled 1.00 for failure rates less than 0.33 (that failure rate which is equivalent to 10-percent plugged condenser tube, after 300,000 hours or 40 years service) and 2.08 for failure rates greater than 0.33. There appears then to be some correlation between high failure rates and shrouded air removal sections. This correlation may have been greater if sufficient data were available for determining failure rates caused only by ammonia concentrations, rather than the total failure rates which were used.

Effect of Condenser Size. An attempt was also made to correlate the failure rate of admiralty tubes and condenser size. Failure rate versus total condensing area was plotted and the condenser manufacturer was noted for each data point. However, no correlation was evident and no attempt was made to do this correlation for other condenser tube materials.

Effect of Operating Hours. An attempt was also made to correlate the total failure rate (all causes) and the total operating hours for admiralty brass in freshwater service. The raw data were plotted (i.e., failure rate vs the time increments given in the Rating Factor subsection) for each of fourteen stations using admiralty brass in freshwater. Separate curves were plotted for air removal tubesets which have been retubed, air removal tubesets now

in use, main-body tubesets that have been retubed, and main-body tubesets now in use. In most cases, the failure rate decreased with time (i.e., the time increments) after an initial increase from zero. In one-third of the remaining cases, the rate of failure rate increase (i.e., the slope of the failure rate vs time curve) decreased with time. The curves for the air removal tubesets (which, in the case of admiralty brass, can be associated with steam-side corrosion failures) and the main-body tubesets were qualitatively identical.

In general, there appeared to be no correlation between failure rate and the time increments and no attempt at this correlation was made for other tube materials. This does not necessarily mean that there is no correlation between failure rate and time. It is obvious that failure rate will decrease with time when only mechanical failures (e.g., falling objects) are considered. Typically, a large number of tubes will be plugged immediately following a mechanical failure and very few will be plugged later (as a result of this failure). On the other hand, an increase of failure rate with time for some corrosion-related failures can be postulated and was indeed observed at some plants.

90-10 Copper-Nickel, CL, CA706

Freshwater Service. Although 90-10 Cu-Ni is primarily considered for seawater applications, 7 percent of the 297 surveyed tubesets used in fresh water were 90-10 copper-nickel. All of the 16 tubesets were at one station. Figure 5-2 shows that 90-10 Cu-Ni has a greater than 90-percent probability of attaining a 40-year life with 10 percent of the tubes plugged.

Seawater Service. Twenty-six percent of the 226 surveyed tubesets used in seawater cooled plants were 90-10 Cu-Ni. There were 58 tubesets. However, the performance of 90-10 Cu-Ni in seawater was relatively poor. Using the 10-percent of tubes plugged criterion, Figure 5-2 shows that there is only a 40 percent probability of attaining a 40-year life in seawater. Since most of the 90-10 Cu-Ni problems occur in seawater, the following discussion will be related primarily to 90-10 Cu-Ni in seawater service.

Erosion-Corrosion Problems. The suggested maximum water velocities for 90-10 Cu-Ni in once-through main condensers are 7.5 feet per second for continuous service and 8.0 feet per second for peak condition excursions.*

*INCO Bulletin, "The Design and Installation of 90-10 Copper-Nickel Sea Water Piping Systems," The International Nickel Company, Inc., New York, N.Y.

The average cooling water velocity in most surface condensers is 7 feet per second. Some tubes may experience somewhat higher velocities while others experience lower velocities as determined by the fluid dynamics in a particular condenser design.

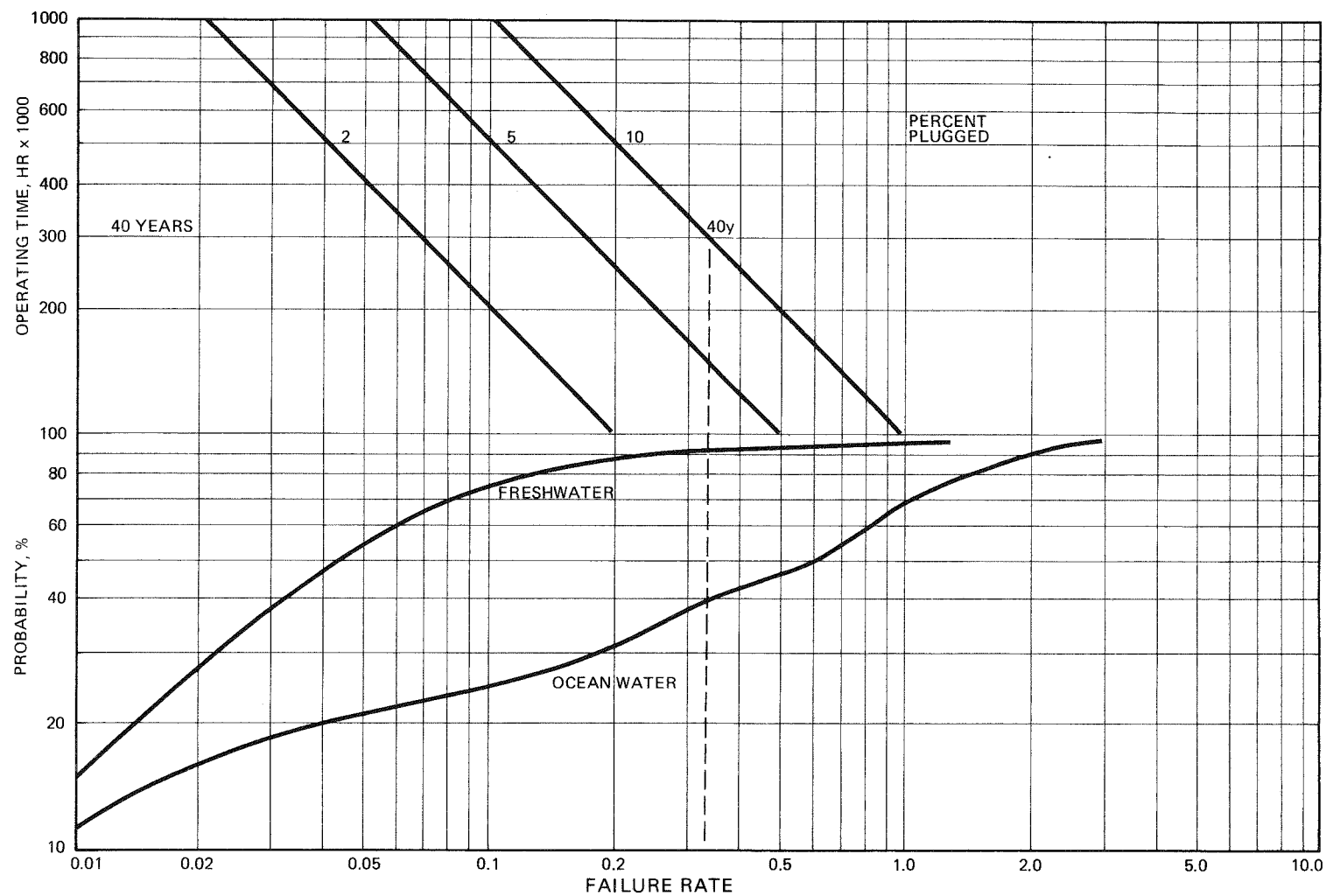
The greatest source of velocity-related problems is partial tube blockage. This is the result of lodged cleaning tools such as brushes and Amertap balls, or of lodged marine life such as mussels. Screens did not seem to deter marine life as small nuclei can pass through the screens, attach themselves to a surface not subject to chlorination, grow, break loose, and finally become lodged in the tubes. Lodged obstructions can reportedly cause localized velocities from two to three times the mean value (142). The effect arises when the presence of an obstruction reduces the flow through a tube to a fraction of the normal amount, so that tube friction becomes small and nearly the entire pressure drop is available to drive water past the obstruction (142).

Other erosion-corrosion problems that occur with 90-10 Cu-Ni and other copper alloys are related to the release of air bubbles from the cooling water or to intermittent cavitation. The impingement of rapidly moving water, particularly where air bubbles are present or where intermittent cavitation occurs, may result in breakdown of protective films and subsequent severe localized or generalized attack of the tube surface.* This action commonly occurs near tube inlet ends where turbulence is highest, but may extend along the entire length. * ** Severe impingement attack on or near the tube outlet can also occur when there is excessive downstream vacuum (66).

Sufficient data were not available at the surveyed plants to determine the percentage of tubes that failed from erosion-corrosion. However, plant personnel did indicate the contributing cause of failure of most tubesets. An erosion-corrosion mechanism was cited as a contributing mechanism in 28 percent of the corrosion-related citations for 90-10 Cu-Ni in seawater.

*Uhlig, H.H., The Corrosion Handbook, John Wiley & Sons, Inc., New York, 1948, p. 545.

**Fontana, M.B., and N.D. Greene, Corrosion Engineering, McGraw Hill Book Co., San Francisco, 1967, P. 78.



G1001892-18

Figure 5-2. Failure Rate vs Probability Curves for 90-10 Cu-Ni in Fresh Water (17 Tubesets) and Seawater Service (55 Tubesets)

Effect of Pollution. A primary weakness of 90-10 Cu-Ni and most other copper alloys is their low resistance to sulfide containing waters. Sulfides generally result from pollution by organic wastes. Decomposition of these wastes lowers the dissolved oxygen content of the water and allows anaerobic sulfate reducing bacteria to convert dissolved sulfate to hydrogen sulfide. Sato (160) has shown that 0.05 ppm sulfide can markedly increase corrosion on aluminum brass tubes. Similar effects will occur in 90-10 Cu-Ni, although the pattern of attack may be more uniform than the other copper-base alloys such as admiralty brass, aluminum brass, or aluminum bronze (92). Experience (* **) has demonstrated that copper-nickel alloys are superior to other copper alloys in tolerating polluted water. INCO has shown, in short-term tests, that 2 to 4 ppm H_2S in seawater will increase the corrosion rate of 90-10 Cu-Ni from 3.0 mils per year (in clean seawater) to 34 mils per year. These corrosion rates were apparently based on weight loss; therefore, the pitting rate may have been significantly higher.

Sulfide films form on copper alloys in polluted waters. These films are considerably more noble than the bare metal. Therefore, breaks in the film can cause severe localized corrosion. This suggests that abrasive cleaning techniques should not be employed in this case.

Only one of the surveyed plants monitored hydrogen sulfide in the cooling water and, in this case, the sensitivity of the instrumentation was only 1 ppm. Therefore, no correlation could be made with degree of pollution or with hydrogen sulfide content. However, the above discussion indicates very low amounts of dissolved hydrogen sulfide (i.e., less than 1 ppm) can cause significant corrosion. It is therefore possible that many of the pitting failures are due to sulfide corrosion.

Contributing failure mechanisms were given for many of the tubesets. Some tubesets had more than one failure mechanism given; others had none. In order to gain some insight on the extent of a particular mechanism, the number of times each failure mechanism was cited was tabulated. As shown in Table 5-8, pitting corrosion was cited 50 percent of the time as a contributing failure mechanism of 90-10 Cu-Ni in seawater.

*Gilbert, P.T., Chem.Ind., July 1959, p. 888.

**Kenworthy, L., Trans. Inst. Mech. Eng., 77, 149, June 1965.

Table 5-8

CONTRIBUTING FAILURE MECHANISMS FOR 90-10 Cu-Ni IN SEAWATER

CAUSE	NUMBER OF TIMES CITED	PERCENT
General corrosion or specific type unknown	15	22
Erosion-corrosion	19	28
Pitting	<u>33</u>	<u>50</u>
TOTAL	67	100

Effect of Iron Additions. The presence of ferrous ions in the cooling water reportedly increases the corrosion resistance of copper-base alloys. The ferrous ions, which result from corrosion of upstream components, e.g., inlet water boxes, or from the deliberate addition of ferrous compounds, e.g., ferrous sulfate, cause the formation of an adherent hydrated ferric oxide (hematite) scale (48). Tests have shown that tubes which are initially covered with a film of ferric hydroxide are even resistant to polluted seawater (clean seawater injected with 0.1 ppm sulfide ion) for at least four to five months. However, the ferric hydroxide deposition is dependent on the initial film already present; e.g., it will not deposit on tubes already covered with a sulfide film (80).

An attempt was made to correlate the performance of 90-10 Cu-Ni in seawater with and without ferrous sulfate additions. Twenty-nine tubesets had been exposed to water containing ferrous sulfate and 29 tubesets had not. As shown in Figure 5-3, neither system has greater than 50-percent probability of attaining a 40-year life with 10 percent of the tubes plugged. However, the tubesets exposed to ferrous sulfate do exhibit a better performance.

Insufficient data were available for evaluating ferrous sulfate injection methods. However, continuous injection is reportedly far superior to intermittent injections of the same gross amount (85). A minimum of 0.03 ppm continuous injection is needed apparently for protection (160).

70-30 Copper-Nickel, CN, CA715

Freshwater Service. Only six of the 297 surveyed tubesets used in freshwater service were 70-30 Cu-Ni. Failure rate data were not available for these tubesets, therefore no performance evaluations were possible for freshwater service.

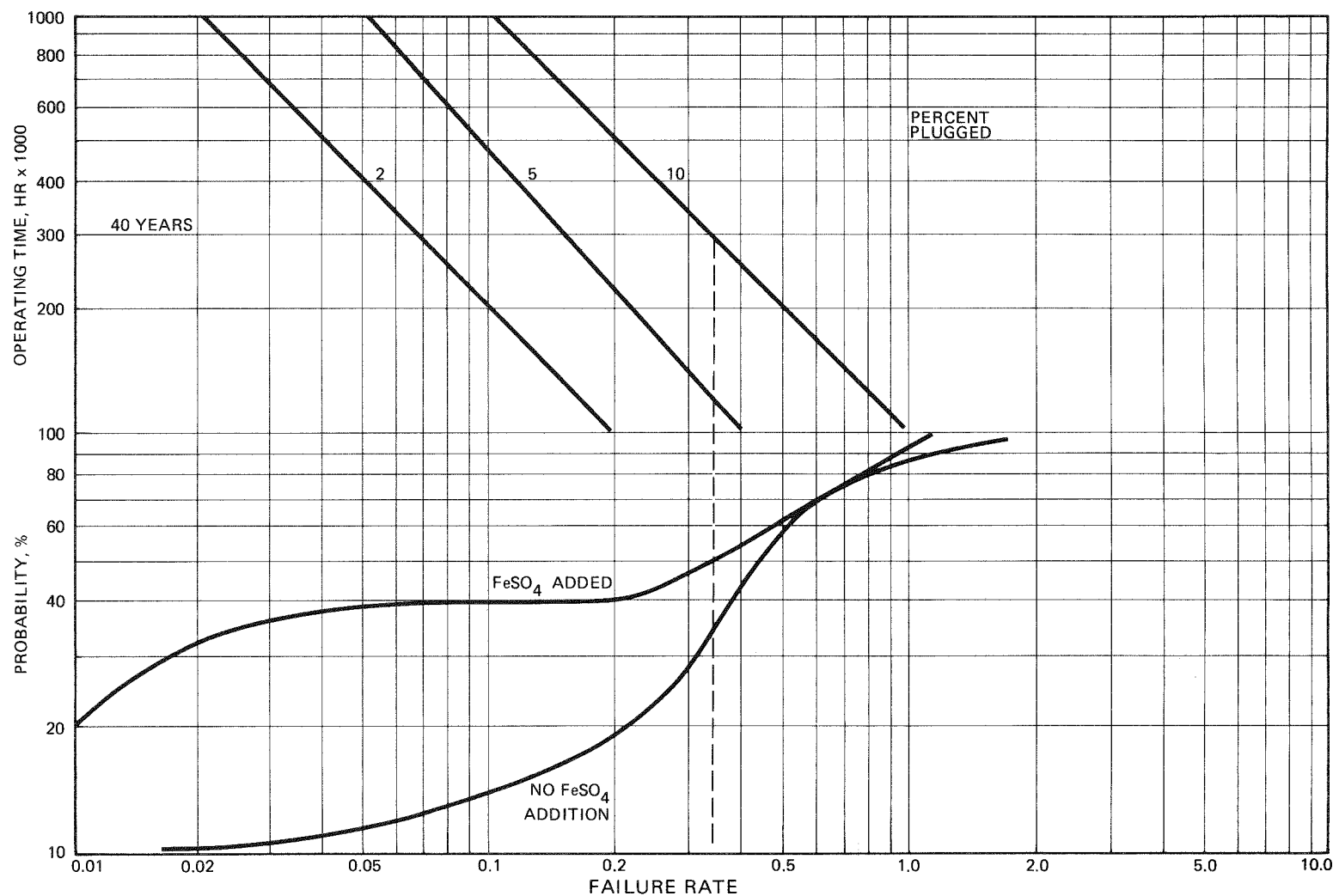


Figure 5-3. Failure Rate vs Probability Curves for 90-10 Cu-Ni in Seawater Service, With (29 Tubesets), and Without (29 Tubesets) FeSO₄ Additions.

Cooling Tower Service. Twelve of the surveyed tubesets used in cooling tower service were 70-30 Cu-Ni. All but one exhibited a zero failure rate.

Seawater Service. Twenty-five percent of the 226 tubesets surveyed at seawater-cooled plants were 70-30 Cu-Ni. Of the 51 tubesets for which failure rate data were available, 45 tubesets or 88 percent were in air removal sections. This indicates that 70-30 Cu-Ni is used primarily for the air removal sections of seawater-cooled condensers. Figure 5-4 shows that 70-30 Cu-Ni is not well suited for seawater service if high reliability and long service life are required. The 6 main-body tubesets had a median FR of 0.102, whereas the 45 air removal tubesets had a median FR of 0.060. Using the 10-percent tubes plugged criterion, 70-30 Cu-Ni is shown to have less than 70 percent probability of providing a 40-year service life. This is a better performance rating than the 40-percent probability for 90-10 Cu-Ni under the same conditions.

Erosion-Corrosion Problems. The recommended maximum design water velocity of 70-30 Cu-Ni tubes in seawater-cooled condensers is 12 feet per second. This is higher than that for 90-10 Cu-Ni.* However, as discussed in the 90-10 Cu-Ni subsection, much higher velocities can result from partial tube blockages. Referring to Table 5-9, 44 percent of the citations for corrosion-related failures showed erosion-corrosion to be a contributing cause.

Table 5-9
CONTRIBUTING CORROSION FAILURE MECHANISMS FOR
70-30 Cu-Ni IN SEAWATER

CAUSE	NUMBER OF TIMES CITED	PERCENT
General corrosion or specific type unknown	15	22
Erosion-corrosion	32	44
Pitting	<u>26</u>	<u>36</u>
TOTAL	73	100

*La Que, F.L., Marine Corrosion, John Wiley & Sons, New York, 1975.

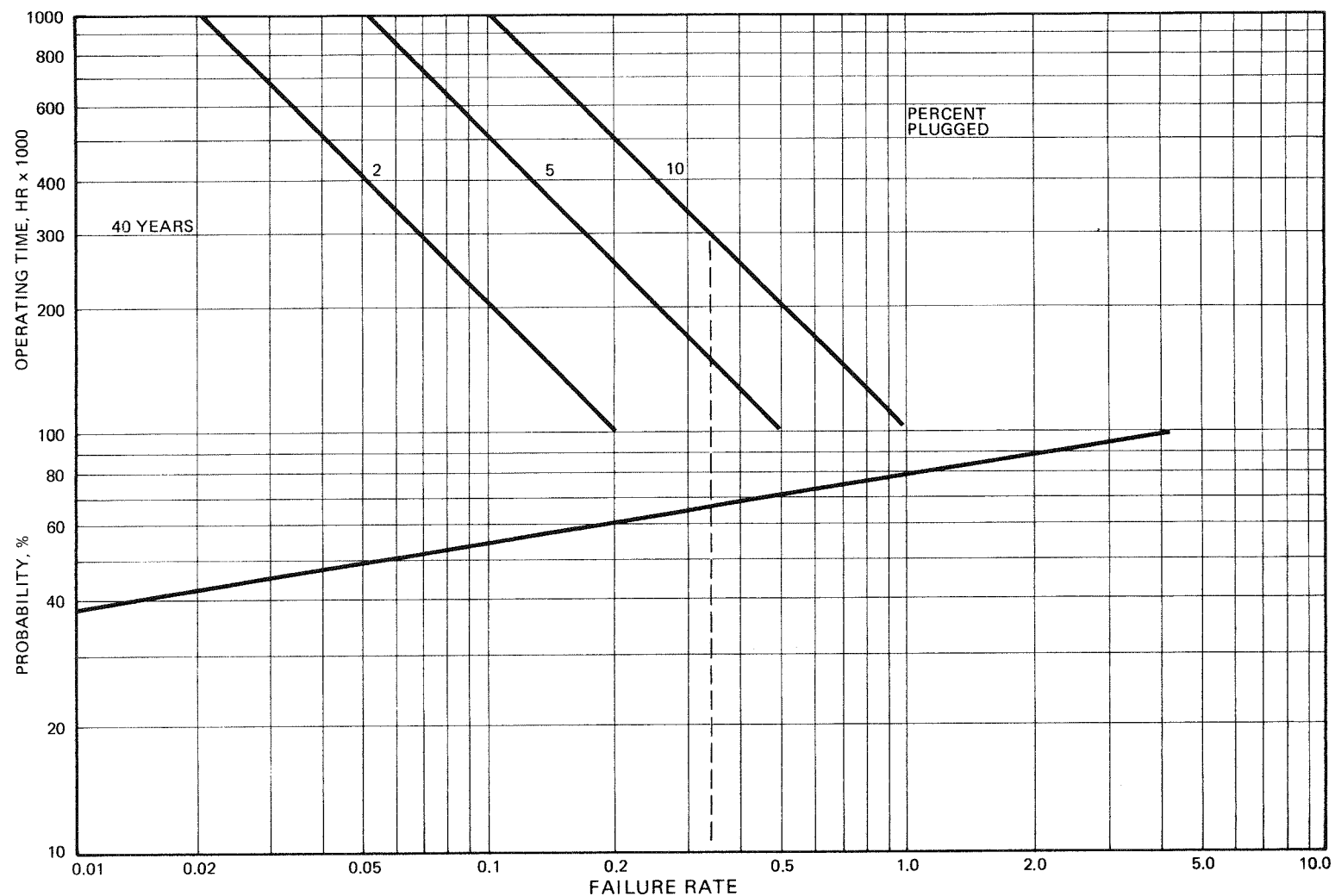


Figure 5-4. Failure Rate vs Probability Curve for 70-30 Cu-Ni in Seawater (51 Tubesets, of Which 6 are Main Body and 45 are Air Removal).

Effect of Pollution. In waters containing sulfide ions, 70-30 Cu-Ni is highly susceptible to corrosion. Since only one plant monitored hydrogen sulfide concentration, no correlations were possible. The cooling water at one plant which had just retubed with 70-30 Cu-Ni became contaminated with an unknown concentration of hydrogen sulfide. These tubesets lasted less than one year. Another station, which had enjoyed relatively good service with 70-30 Cu-Ni for several years, began to experience numerous failures when the intake canal was stirred up during construction of the intake system for a new unit. Hydrogen sulfide was suspected of causing the failures although H_2S was not detected by the monitoring system. However, the sensitivity of the instrumentation was only 1.0 ppm H_2S . As stated in the 90-10 Cu-Ni subsection, sulfide concentrations of 0.05 ppm have been shown to significantly increase corrosion.

Effect of Iron Additions. Twenty-four 70-30 Cu-Ni tubesets had been exposed to water containing ferrous sulfate and 33 had not. Figure 5-5 indicates that a significant increase in performance was achieved when ferrous sulfate was added to the water. Greater than 90 percent probability of achieving a 40-year life with only 2 percent of the tubes plugged is indicated when ferrous sulfate was added. However, these data should be considered cautiously. The tubesets in the two stations which were known to have sulfide-contaminated water did not use ferrous sulfate additions.

Aluminum Brass, BA, CA687

Freshwater and Cooling Tower Service. None of the stations surveyed used aluminum brass in fresh water or cooling tower waters.

Seawater Service. Excessive impingement-attack failures of admiralty brass tubes in turbine condensers used in the British navy prompted the research programs that lead to the development of aluminum brass, as well as the copper-nickel alloys. The goal was to provide greater reliability in turbine condenser applications on ships, seashore power plants, and other heat exchangers using seawater for cooling.* Twenty-three percent of the 226 surveyed tubesets used in seawater-cooled plants were aluminum brass. Figure 5-6 shows that there is less than 50 percent probability that aluminum brass tubes will provide a 40-year life in seawater with not more than 10 percent tubes plugged. Therefore, this alloy appears to be unsatisfactory for service that requires high reliability and a long service life.

*La Que, F.L., op cit.

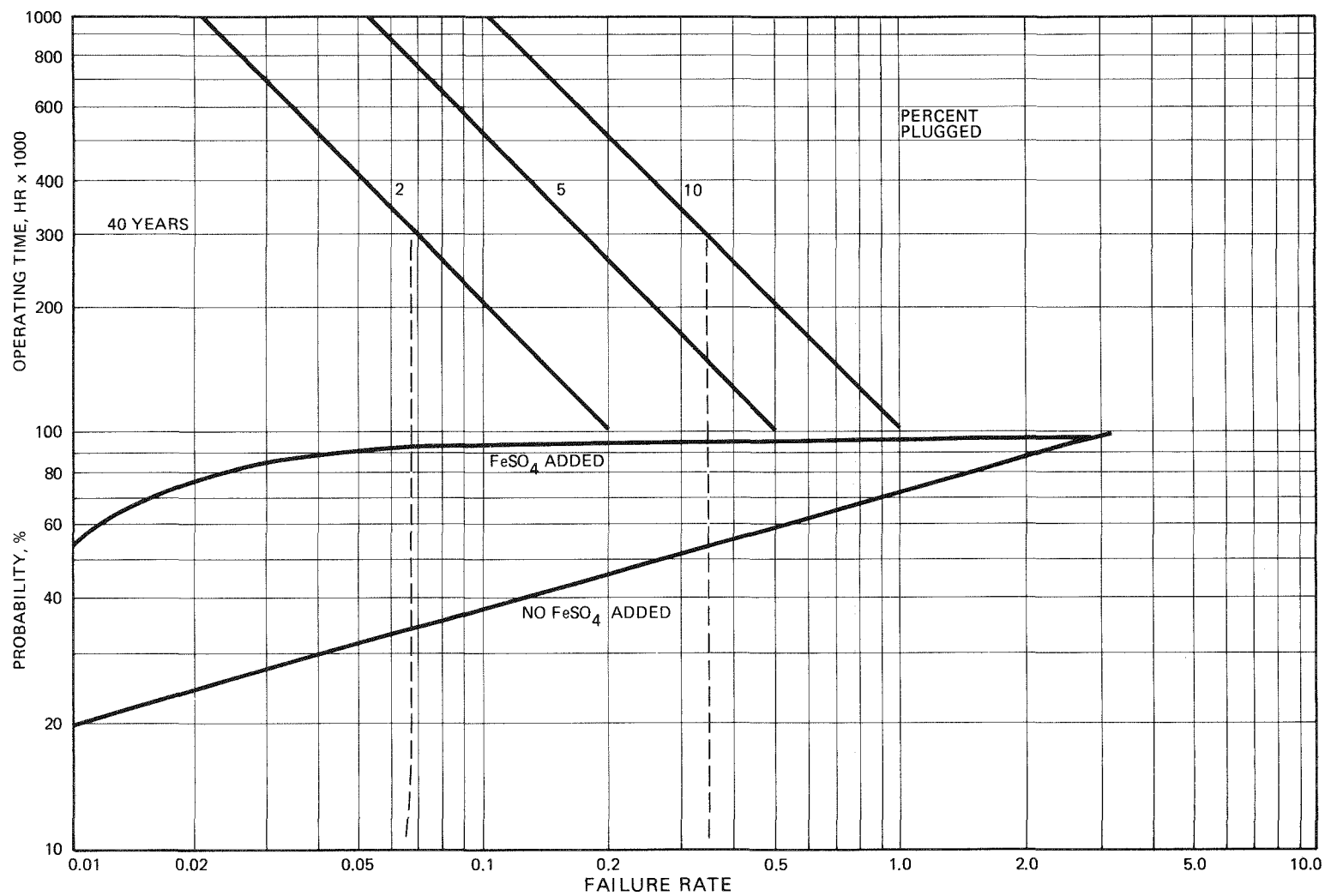


Figure 5-5. Failure Rate vs Probability Curves for 70-30 Cu-Ni in Seawater With (24 Tubesets) and Without (33 Tubesets) FeSO₄ Additions.

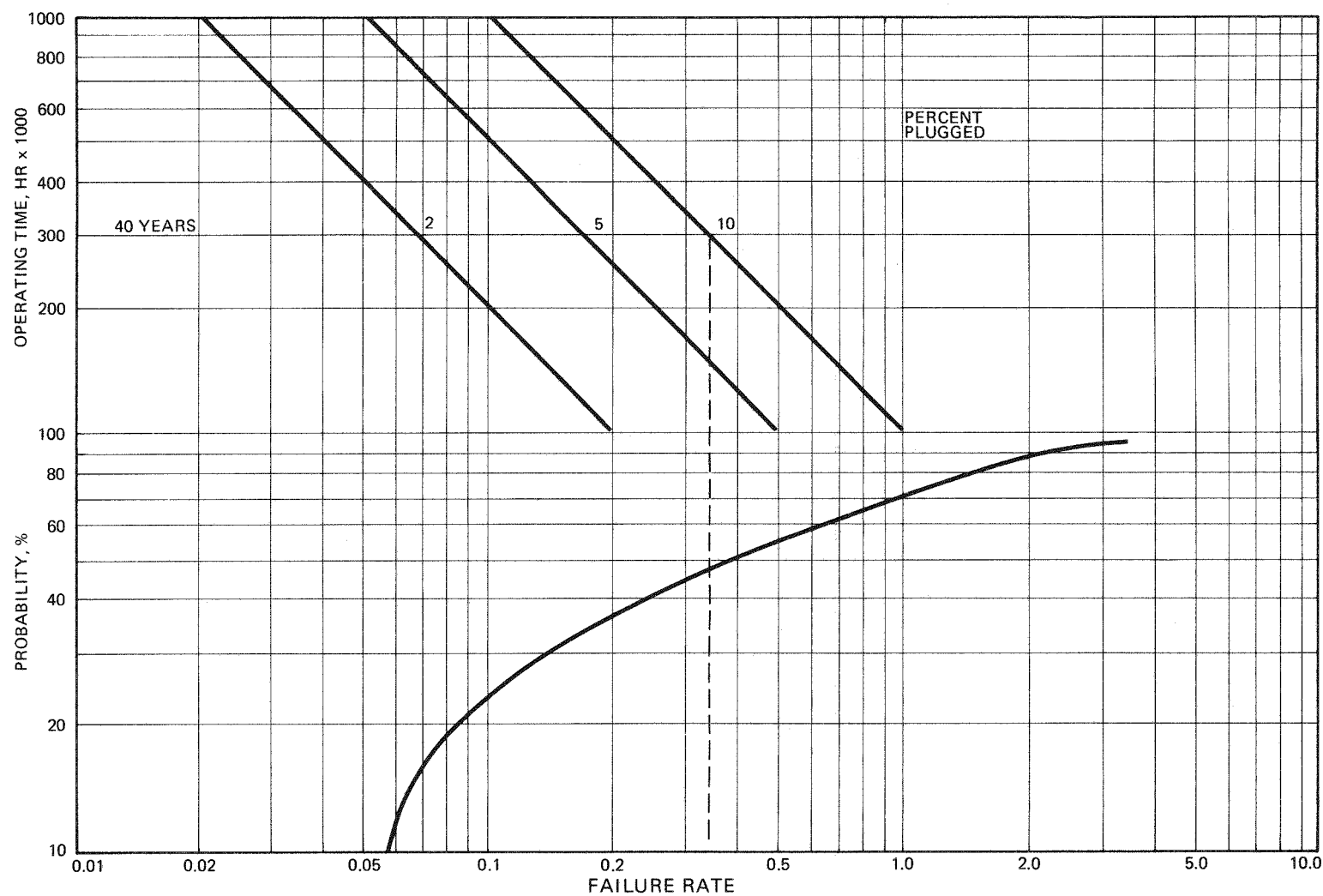


Figure 5-6. Failure Rate vs Probability Curve for Aluminum Brass in Seawater (37 Tubesets).

Erosion-Corrosion Problem. The recommended maximum-design water velocity for aluminum brass tubes in seawater-cooled condensers is 8 feet per second.* Therefore, small deviations from the normal condenser design velocity, i.e., 7 feet per second, will cause problems in aluminum brass tubing, even if partial tube blockages and localized turbulence can be eliminated. This is reinforced by the data in Table 5-10 which show that erosion-corrosion was cited 65 percent of the time as contributing to corrosion related failures of aluminum brass in seawater.

Table 5-10

CONTRIBUTING CORROSION FAILURE MECHANISMS FOR
ALUMINUM BRASS IN SEAWATER

CAUSE	NUMBER OF TIMES CITED	PERCENT
General corrosion or specific type unknown	6	22
Erosion-corrosion	26	65
Pitting	<u>8</u>	<u>20</u>
TOTAL	40	100

Effect of Pollution. Aluminum brass is highly susceptible to waters containing sulfide ions. INCO test data indicate that aluminum brass has a susceptibility similar to that of the copper-nickels to polluted seawater.**

Effect of Iron Additions. Thirty-two aluminum brass tubesets had been exposed to water with no ferrous sulfate additions while only four tubesets had been exposed to water with ferrous sulfate. These four tubesets were located at one station and were exposed to one of the most polluted bodies of water in the country. Figure 5-7 indicates that in this case, poorer performance was attained with the ferrous sulfate additions than with tubesets not exposed to ferrous sulfate. However, as discussed earlier, the ferric hydroxide deposition is dependent on the initial film already present and it will not deposit on tubes already covered with a sulfide film. Therefore, ferrous sulfate offers no protection for tubes already covered with a sulfide film. The operating history of the particular condenser was such that sulfide-free surfaces were probably never available. Therefore, the curves in Figure 5-7 may be misleading.

*La Que, F.L., op cit.

**Correspondence from Development and Research Department, International Nickel Company, Inc.

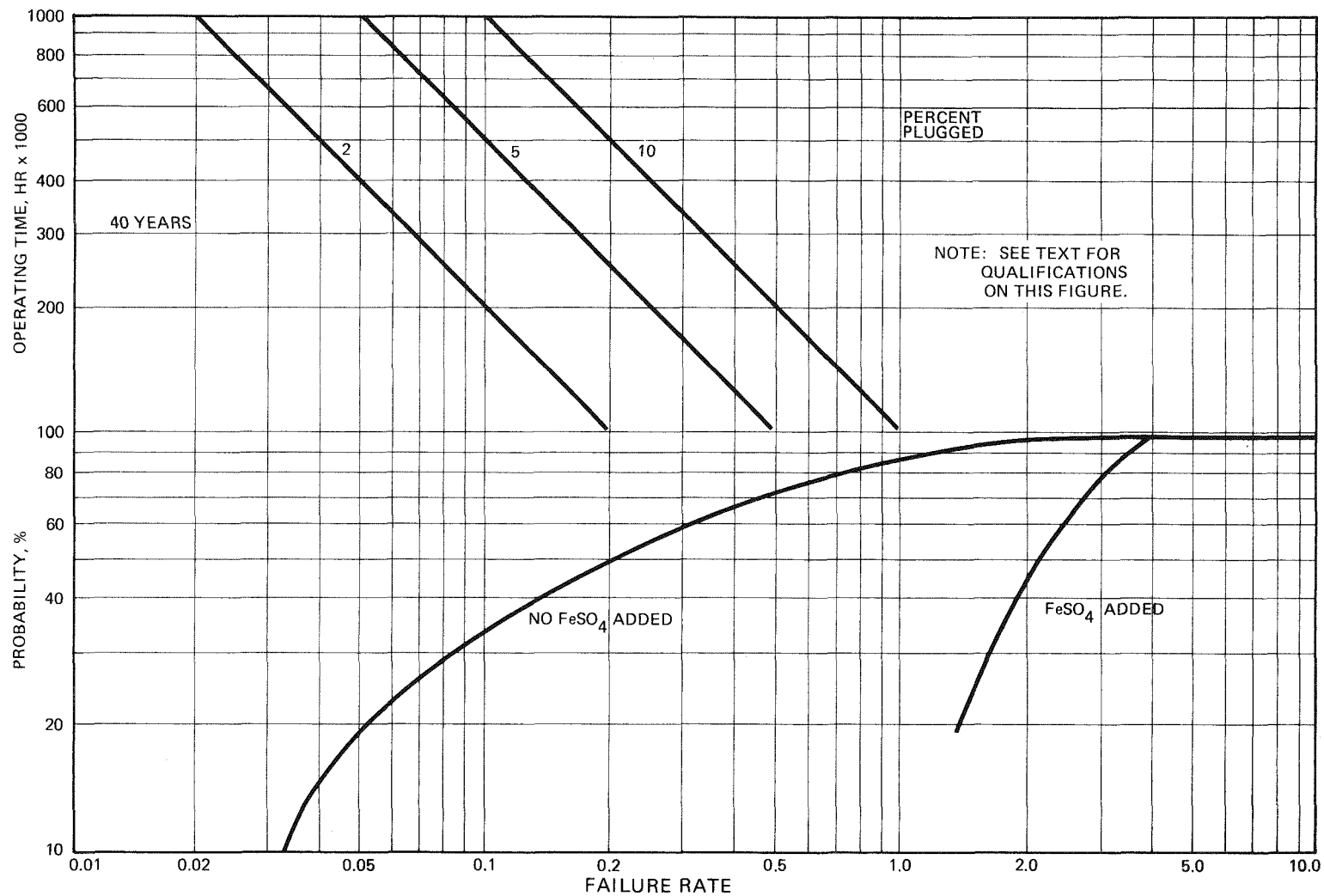


Figure 5-7. Failure Rate vs Probability Curves for Aluminum Brass in Seawater Service With (4 Tubesets) and Without (32 Tubesets) FeSO_4 Additions.

Aluminum Bronze, AB, CA608

Although aluminum bronzes are commonly used in seawater, very few applications involve condenser tubes. Only 12 tubesets, all in seawater-cooled plants, utilized aluminum bronze tubes. These were installed at two stations. Eight tubesets have been replaced with another alloy and the other 4 soon will be. Figure 5-8 indicates a low probability that aluminum bronze will provide a 40-year service life with less than 10 percent of the tubes plugged.

Because of the small data base, no evaluation could be made of the effects of ferrous sulfate addition. Ferrous sulfate was used at one station and not at the other. High failure rates were observed at both stations.

Contributing failure mechanism citations are given in Table 5-11. Most failures appear to be related to waterside corrosion; pitting corrosion is the mechanism cited most often.

Table 5-11

CONTRIBUTING FAILURE MECHANISMS FOR ALUMINUM BRONZE

CAUSE	NUMBER OF TIMES CITED	PERCENT
General corrosion or specific type unknown	6	25
Erosion-corrosion	6	25
Pitting	<u>12</u>	<u>50</u>
TOTAL	24	100

STAINLESS STEELS

Since the early 1960s, increasing interest has been shown in stainless steel tubing for large surface condensers. In this survey, 169 or 29 percent of the 580 total tubesets were stainless steel as indicated in Table 5-1. Likewise, Table 5-4 shows that 20 percent of the tubes and 20 percent of the total condensing surface area in the surveyed plants were fabricated from either Type 304 or Type 316 stainless steel. Type 304 accounts for 99.6 percent of the stainless steel condenser tubing surface area. Table 5-12 lists the composition of these stainless steels and the designations used in this study.

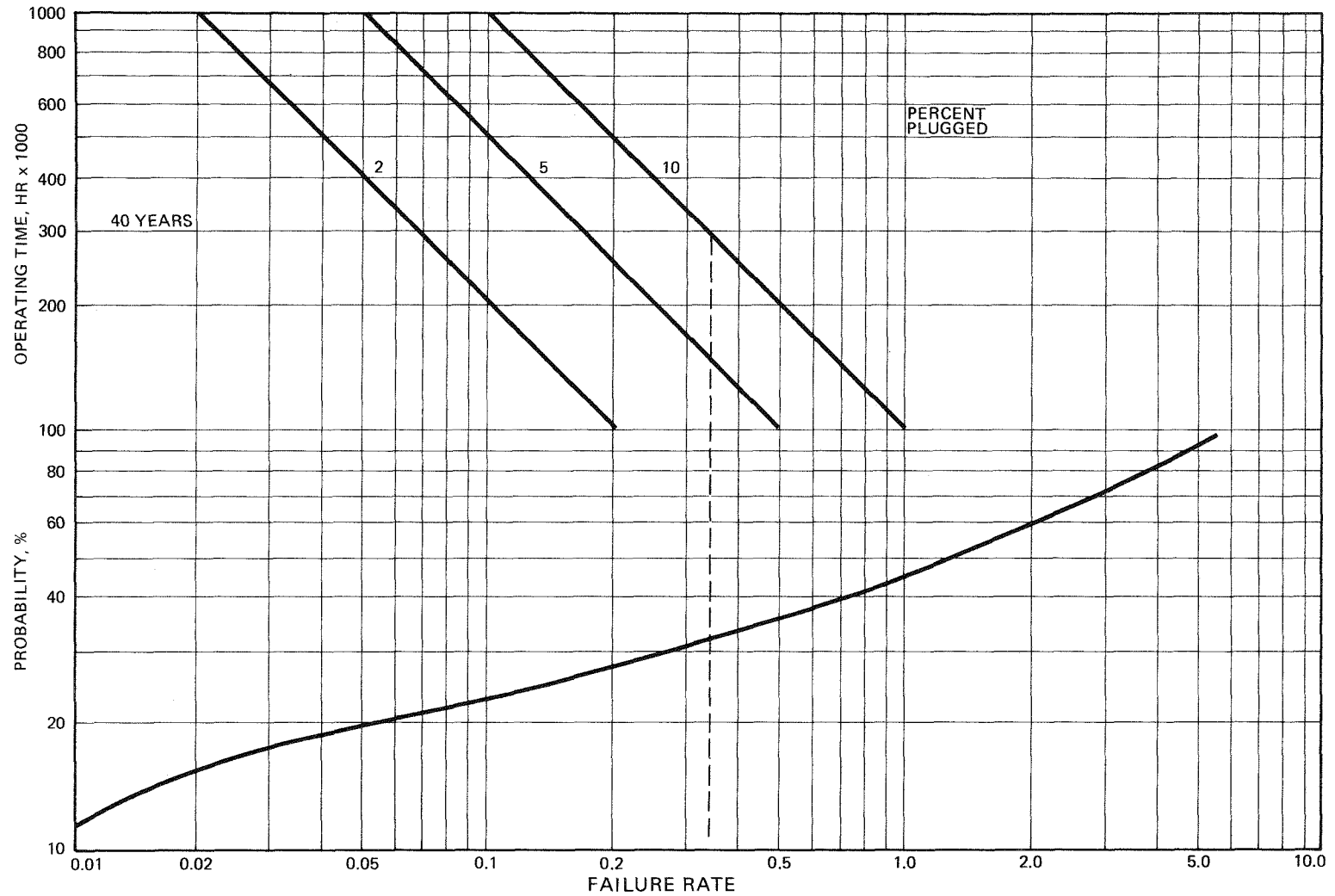


Figure 5-8. Failure Rate vs Probability Curve for Aluminum Bronze in Seawater Service (12 Tubesets).

Table 5-12

STAINLESS STEEL -
CHEMICAL COMPOSITION AND DESIGNATIONS

SS Alloy	Study Designation	COMPOSITION							
		Carbon, max	Manganese, max	Phosphorus, max	Sulfur, max	Silicon, max	Nickel	Chromium	Molybdenum
Type 304	SS	0.08	2.00	0.040	0.030	0.75	8.0 to 11.0	18.0 to 20.0	---
Type 316	ST	0.08	2.00	0.040	0.030	0.75	11.0 to 14.0	16.0 to 18.0	2.00 to 3.00

Erosion-Corrosion. Stainless steels show much greater resistance to erosion-corrosion than copper-base alloys. There is no recommended maximum water velocity design limit for stainless steel tubing in condenser service. Erosion by cooling waters has not been a problem. In fact, erosive waters such as those containing large amounts of suspended solids actually improve the performance of stainless tubing by maintaining a cleaner surface. In many cases, stainless steel tubing has been used for the steam impingement areas in order to take advantage of its erosion resistance where a distinct impingement zone could be determined. Stainless steel was used in these sections in 76 percent of the surveyed freshwater condensers.

Ammonia Attack. Stainless steels are immune to ammonia attack and to ammonia-induced stress corrosion cracking. For this reason, they are also used in air removal sections where the ammonia concentration may be high. In the surveyed freshwater condensers, stainless steels were used in 54 percent of the identifiable air removal sections.

Chloride Stress Corrosion Cracking. On the basis of both the field survey and the literature search, as well as discussions with cognizant individuals, chloride-induced stress corrosion cracking has not been observed in stainless steel tubing used in power plant condensers. The cooling water temperature in most condensers is below the so-called critical temperature for stress corrosion cracking, i.e., 120 to 140°F in practical applications. Stress corrosion

cracking perhaps could occur when cooling towers are used which result in higher temperatures (100 to 120°F). However, it is more likely that stainless steel will fail first by other mechanisms, e.g., pitting corrosion.

Pitting Corrosion. One weakness of Type 304 and 316 stainless steels is their susceptibility to pitting corrosion. This susceptibility is increased when the cooling water has a high chloride concentration, e.g., ocean water or some cooling tower waters. Pitting attack is aggravated by stagnant or low flow conditions in which solids can settle on the tube surface. Small concentrations of manganese were identified as the cause of pitting corrosion in at least one case.

The addition of molybdenum to stainless steels increases their resistance to pitting corrosion. Type 316 has a molybdenum content of 2 to 3 percent. This amount of molybdenum apparently is not required in most condensers cooled by fresh water with a low chloride concentration, but it is too low for ocean and brackish cooling waters which have a high chloride concentration.

Allegheny Ludlum alloy 6X, which has a nominal molybdenum content of 6.5, shows promise in overcoming the pitting problem in high chloride waters. Test tubes have given up to six years of service in seawater cooled condensers without a failure.* Recently, two seawater-cooled condensers have been completely retubed with AL6X.

Type 304, Stainless Steel, SS

Freshwater Service. Thirty-nine percent of the 297 surveyed tubesets in fresh water were Type 304 stainless steel. For the 95 tubesets with known failure rates, 27 percent were used in the main-body section, 45 percent were used in the air removal section, and 28 percent were used in impingement sections.

Figure 5-9 shows that when only main body and air removal tubesets are considered (Curves A and B), the performance of Type 304 stainless steel in fresh water is excellent. A greater than 90 percent probability is indicated that the tubes will provide a 40-year life with less than 2 percent of the tubes plugged. Curve B shows the probability versus failure rate obtained when all available total failure rate data for Type 304 stainless steel tubes in freshwater service

*Personal Communication from J. Maurer of Allegheny Ludlum on November 15, 1976.

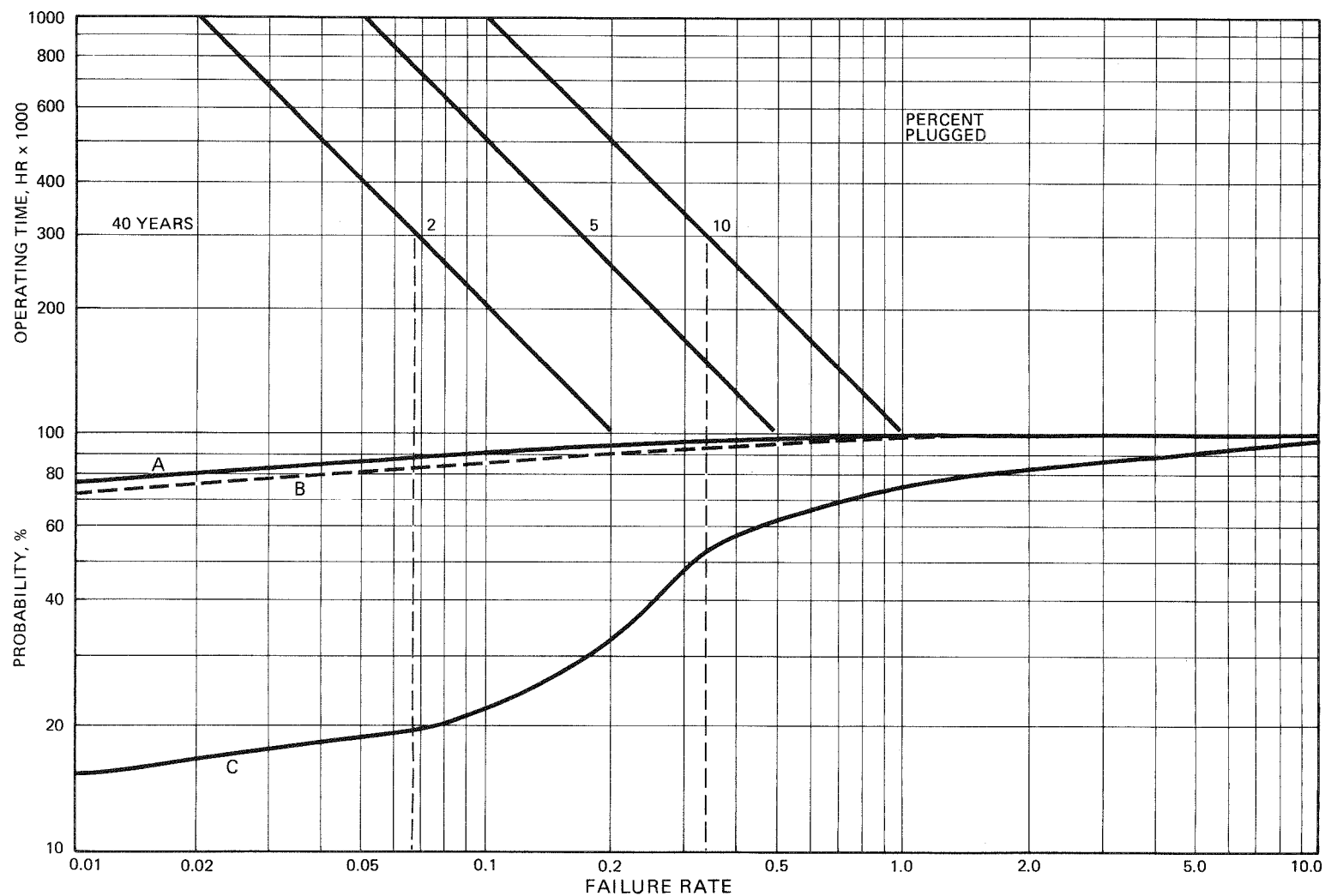


Figure 5-9. Failure Rate vs Probability Curves for Type 304 Stainless Steel in Freshwater Service; Curve A-A and M Tubesets (Guard Plugs at One Station Deleted) (64 Tubesets); Curve B-A and M Tubesets (No Exclusions); Curve C-I Tubesets (27 Tubesets).

is plotted. An unusually large number of guard plugs were used in one condenser although only two leaking tubes had actually been discovered. Since this large number of guard plugs distorts the data, Curve A was plotted to more realistically show the performance of SS 304 in main body and air removal service.

The performance of impingement sections (Curve C) is somewhat lower. Using the 10-percent tubes plugged criterion, less than 60 percent probability is indicated that these tubes will provide a 40-year service life. Failures in the impingement section are usually due to projectiles or steam impingement. Failures from such causes are not a function of the tubing material. Such failures are also independent of time. Accordingly, calculation of the failure rate for impingement sectors is of questionable value.

Cooling Tower Service. Thirty-seven percent of the tubesets in cooling tower service were Type 304 stainless steel. Although Figure 5-10 indicates that Type 304 stainless steel will provide good performance in cooling tower service, the data may be misleading. Failure rate data were available for only 13 of the 21 tubesets surveyed. Severe corrosion occurred in the tubesets for which no failure rate data were available. Therefore, the performance curve in Figure 5-10 would probably be much lower if data from these tubesets were available or if the data base were larger.

Contributing Failure Mechanisms. As discussed earlier, contributing failure mechanisms were given for many of the tubesets. Some tubesets had more than one failure mechanism given. Table 5-13 shows the distribution of all contributing failure mechanisms (similar tables in the copper alloy section listed only corrosion related failures) for Type 304 stainless steel in fresh water.

The significant feature of Table 5-13 is that only 2 percent of the failure mechanism citations were related to water-side corrosion. Eighty-nine percent of these failures were related to steam-side mechanical failures and 9 percent to faulty tube rolling.

Insufficient data were available for comparing contributing failure mechanisms in the cooling tower tubesets. As noted above, at one plant with a cooling tower Type 304 tubes experienced severe pitting corrosion.

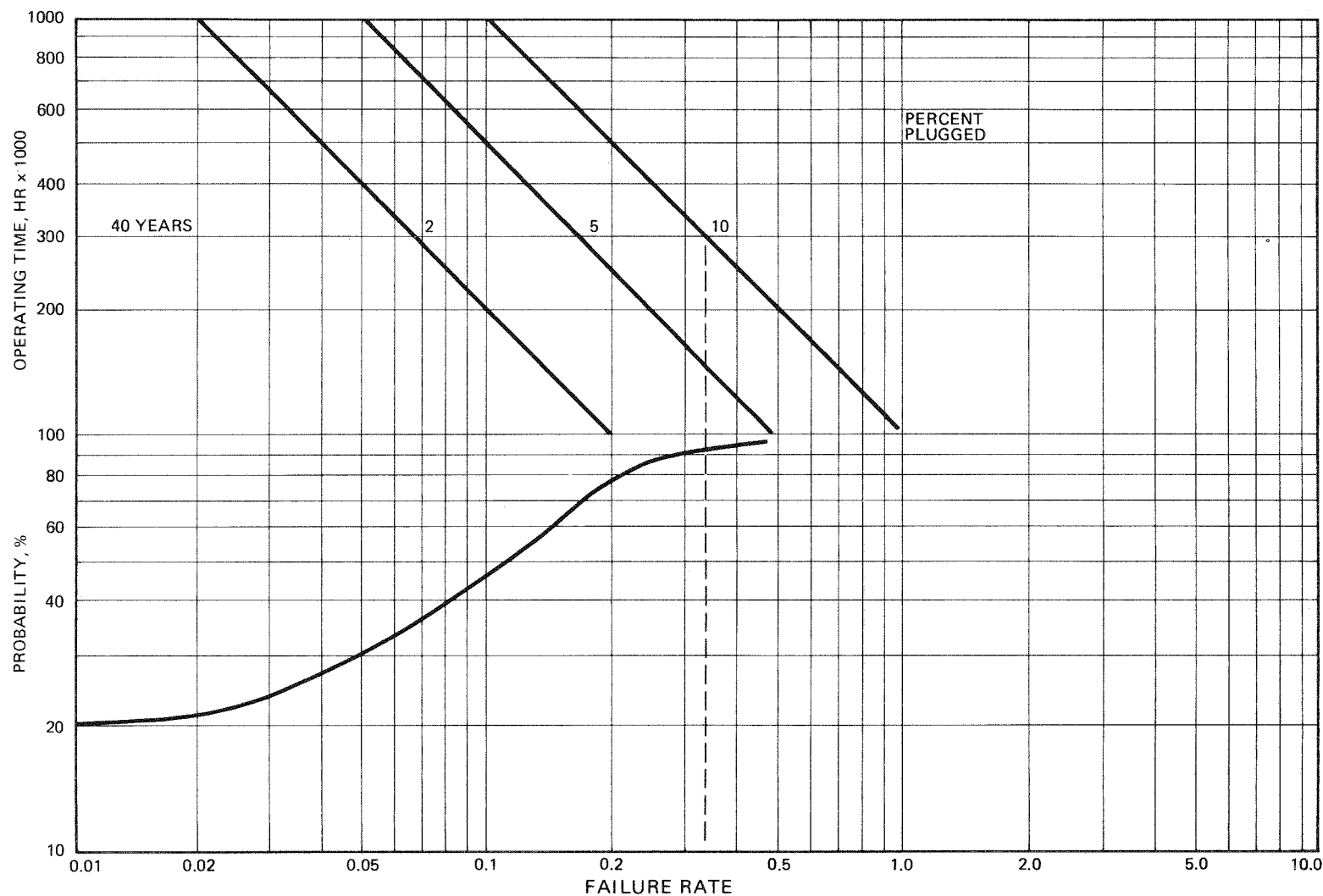


Figure 5-10. Failure Rate vs Probability Curve for Type 304 Stainless Steel in Cooling Tower Service (13 Tubesets). (Note: As explained in the text, this curve may be misleading.)

Table 5-13

CONTRIBUTING FAILURE MECHANISMS
FOR TYPE 304 STAINLESS STEEL
IN FRESH WATER

CAUSE	NUMBER OF TIMES CITED	PERCENT
Falling objects	36	38
Mechanical	17	18
Steam erosion	16	17
Vibration	15	16
Faulty tube rolling	8	9
General corrosion or specific type unknown	2	2
TOTAL	94	100

Effect of Chlorides. It is well known that chloride ions increase the susceptibility of stainless steel to pitting and crevice corrosion. It has also been shown that susceptibility to pitting and crevice corrosion increases with temperature.* **

However, the critical chloride concentrations and temperatures above which pitting in Type 304 and other stainless steels will occur have not been defined. Chloride concentrations in the cooling water ranged from 7 to approximately 120 ppm at the 12 surveyed plants which used Type 304 stainless steel tubing. The average and median failure rates for the 21 tubesets (2 stations) exposed to approximately 100 ppm chloride cooling water were 0.074 and 0.0, respectively. These values are considerably less than the 0.333 failure rate which corresponds to a 40-year life with less than 10 percent of the tubes plugged. The average to date service life of these tubesets is 9.5 years and all are original tubesets. Station practices did not include special cleaning or maintenance procedures for these tubes. Therefore, it would appear that cooling water chloride concentrations of approximately 100 ppm may not be a problem for Type 304 stainless steel tubing when the condenser operating temperatures are approximately 100 to 110°F.

*Brigham, R.J. and E.W. Tozer, "Temperature as a Pitting Criteria," Corrosion Vol 29, No. 1, January 1973, p 33.

**Correspondence from Development and Research Department, International Nickel Company, Inc.

Maintenance and Cleaning Procedures. Table 5-14 summarizes the layup and cleaning procedures used by those utilities that had Type 304 stainless steel condenser tubing in freshwater service.

Type 316 Stainless Steel, ST

Freshwater Service. Only 3 percent of the surveyed freshwater tubesets were Type 316 stainless steel. These were all used in either the air removal or impingement sections of the condensers. The median failure rate for these tubesets was 0.00. Contributing failure mechanism data were not available for Type 316 stainless steel tubesets used in fresh water.

Cooling Tower Service. Type 316 stainless steel condenser tubes were not used at any of the surveyed stations which had cooling towers.

Seawater Service. Ten percent of the 226 tubesets in seawater-cooled condensers were Type 316 stainless steel. The failure rates (data were available for only 9 of these tubesets) ranged from 0.116 to 28.571. The average and median failure rates were 5.568 and 1.933, respectively. Such failure rates confirm that Type 316 stainless steel is not well suited for seawater or brackish water service. Specific failure mechanisms were cited 27 times for Type 316 stainless steel in seawater. Pitting corrosion accounted for 59 percent of the citations, erosion-corrosion for 30 percent, and general corrosion or specific-type-unknown for 11 percent.

TITANIUM, TI

Titanium as a tubing material for domestic steam power plant surface condensers first was investigated in 1959 when 7 test tubes were installed (262).* The first condenser with all-titanium tubes was put into service in May 1972.**

*"Titanium Tubing for Surface Condenser Heat Exchanger Service, Bulletin SC-3," Titanium Metals Corporation of America, April 1975, p.5.

**"Installation List, TIMET Codeweld Condenser Tube," Titanium Metals Corporation of America, April 1976.

Table 5-14

MAINTENANCE AND CLEANING PROCEDURES USED
FOR TYPE 304 STAINLESS STEEL TUBING

STATION	COOLING WATER CHLORIDE CONCENTRATIONS, ppm	NORMAL CLEANING PROCEDURES	LAYUP DURING OUTAGES
A	7-14	Backwash once a week or as needed. Cleaning with plugs once a year	Drain and let dry
B	14-72	Water lance twice a year	Drain only
C	~23	None	Unknown
D	100-120	None	Drain and dry
E	7-10		Short-Leave circulating water pumps on Long-Drain, dry, and clean with nylon brushes
F	Not available (Conductivity: 60-90 μ mho)	Amertap	Short-None Long-Drain only
G	10-13	Backwash	Leave circulating water pumps on
H	100-120	None	Drain and dry
I	Not available	None	Leave circulating water pumps on
J	Not available (~135TDS)	None	None
K	12-13	Backwash every shift; use water and air gun twice a year	Leave circulating water pumps on If entry required, backwash, drain, and flush with deionized water
L	60	Backwash when needed; clean with brushes when needed	Drain only

Major installations of titanium tubing have been in service in seawater distillation plants since 1965 (242). With regard to steam condensers using titanium tubing, the following describes a typical operating installation. This description is not intended to stereotype the application of titanium but to broadly represent its present use in operating plants as of the time of this survey.

- Tubing -- manufactured to ASTM specification B-338, Grade 2; 7/8 in. (2.22 cm) or 1 in. (2.54 cm) O.D., 22 BWG wall thickness; seam welded; supplied by Titanium Metals Corporation of America (TIMET)
- Tube-to-Tubesheet Joint -- rolled, often with grooved tube-sheet holes; muntz metal (or aluminum bronze) tubesheet material (most tubesheets were existing in condensers retubed with titanium)
- Circulating Water -- high in dissolved solids; often low in dissolved oxygen and with high pollutant concentrations
- Installed by retubing existing condenser; installation in new condensers designed for titanium tubes has occurred only recently

Under the general conditions outlined above, the performance of the material has been very good.

The basic material specification requirements for titanium as used in condensers* (6-p.124) are given by ASTM B338-76, Grade 2. The ASTM chemical composition limits are as follows:

Nitrogen, max	0.03%
Carbon, max	0.10%
Hydrogen, max	0.015%
Iron, max	0.30%
Oxygen, max	0.25%
Other elements (each), max	0.1%
Other elements (total), max	0.4%
Titanium (by difference)	remainder

*"Titanium Tubing, Bulletin SC-3," p.7.

Commercially pure titanium is unique in that it is the only condenser tube material that is used in an unalloyed form.

Seamless titanium has been tested by some utilities in the U.S., but it is not cost competitive with seam-welded tubing. The Japanese use seam-welded tubing in their condenser applications (135). In Britain seamless titanium tubing has been used in power station condensers (6-pp. 124, 127-128).

TIMET, which has supplied the titanium tubing for all U.S. condenser installations except one since Septemeber 1976, has provided eddy current, pneumatic, and ultrasonic inspections on all production tubing. Hydrostatic testing is provided at extra cost when requested.

Survey Results

One of the original objectives of the study was to survey steam power plants containing a significant number of titanium condenser tubes. Completed mail survey forms were received from all 14 units that had titanium condenser tubes in service. Seven of the responses stated that zero failures of titanium tubing had occurred. The remaining 7 responses were understood as indicating very few, if any, failures, but could not be definitely interpreted as zero failures. The following points will gnerally summarize the mail survey information received:

- Ten of the 14 units were retubed in whole or in part with titanium. The previous tubing material had been aluminum brass, aluminum bronze, 90-10 copper-nickel, or 70-30 copper-nickel.
- The average dissolved solids in the once-through circulating water ranged from 5,000 to 32,000 ppm at the 10 retubed units.
- Two of the units with original titanium tubing use fresh to slightly brackish cooling water (including one cooling tower installation). At the other 2 locations, seawater is used for cooling water.
- The Amertap cleaning system is used continuously or intermittently on 3 of the 14 installations (it is available but not used on a fourth unit); 2 other units clean intermittently with brushes or plugs; 10 units reported the use of chlorination.

Of these 14 operating units with titanium tubing, 10 were visited during the field survey. Also included in the field survey were two units that had titanium tubing installed subsequent to the mail survey. The extent of the survey and performance results are summarized below:

- Eleven of the 12 units were not originally tubed with titanium.
- Thirty-one tubesets of titanium were defined at the 12 units included in the field survey.
- A total of 164,000 titanium tubes was included. The average operating life was about 14,000 hours.
- The seven titanium tubes initially installed in 1959 for test purposes in polluted, brackish cooling water have performed without evidence of corrosion after approximately 91,000 hours of service as of April 1973 (127,262).
- The data for all known titanium failures as of early December 1976 show 22 tubesets with zero failures and 9 tubesets with known failures. For the 9 tubesets with failures, the stations reported the following:

Cause of Tube Failures	Number of Tubesets	Number of Failed Tubes
Steam Impingement	1*	15
Vibration Damage	5**	26
Mechanical Damage	3*	6
Unknown	1	1
TOTAL	9	48

*One tubeset had 2 types of failure causes.

**At one unit, approximately 300 plugged tubes were replaced recently with new titanium tubes. The new tubes were staked to control vibration.

The overall performance of titanium is indicated in Figure 5-11. The field survey data show that titanium condenser tubes have a high reliability. Titanium tubes have a 87 percent probability of operating for 40 years with not more than 2 percent plugged tubes and a 94 percent probability of 40-years service with not more than 1 percent plugged tubes. The median failure rate

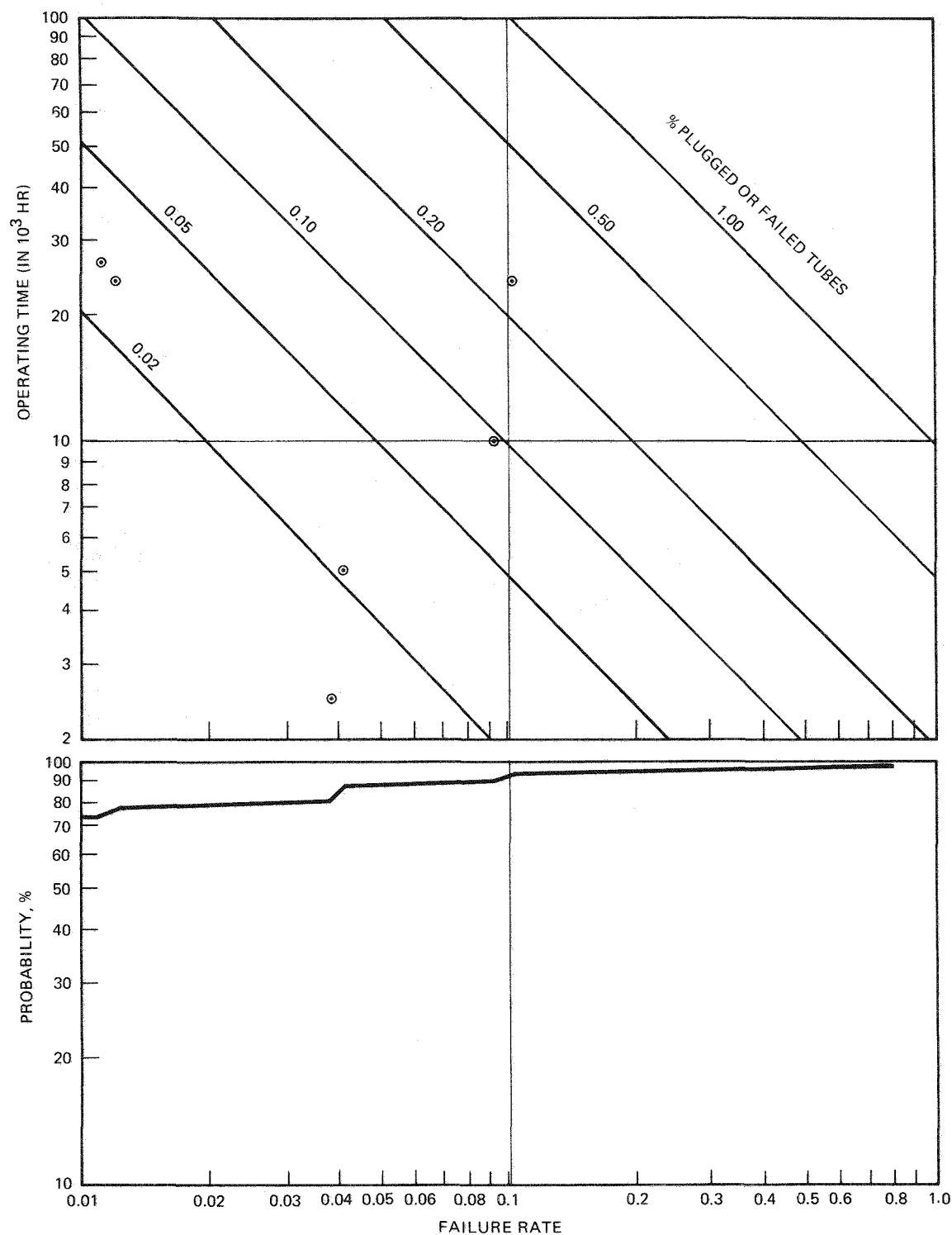


Figure 5-11. Failure Rate vs Operating Hours and Failure Rate vs Probability for Titanium Tubing

value for the tubsets surveyed is zero. Some qualifications should be observed when considering these probabilities and statistics:

- The known causes of failure have been vibration, steam impingement, or mechanical damage. Vibration damage generally tends to manifest itself early in the life of a tubset. Steam impingement also usually occurs early in the service life but can result from additions of drain lines, etc, later in the life of the condenser. These two problems can usually be permanently solved by staking and baffling of steam jets, respectively. Mechanical damage (turbine-generated missiles, dropped tools, broken baffles) can occur at any time. It is independent of tube material and cannot be prevented from recurring although precautions can be taken to limit its frequency. Given such failure mechanisms, the above anticipated service life probabilities are probably low.
- The average tube age is about 14,000 operating hours (about 2 calendar years). The age of the oldest titanium installation surveyed is 5-1/2 years. Although titanium, unlike other tubing materials in condenser service, is virtually immune to pitting, corrosion, erosion, stress corrosion, etc (as described later) any possible long-term deleterious factors could not be determined due to the relatively short lives of the surveyed tubsets. The above service life probabilities should be viewed with this in mind.
- The above service life probabilities include the effect of plugs in tubes that have not failed (guard plugs and plugs resulting from removal of inspection tubes). If only failed tubes were included, the above probabilities would be substantially higher.

Discussion Items

A number of technical factors relate to the use and performance of titanium tubing in surface condensers. These are enumerated below, followed by a synopsis of the information found in the literature and field investigation.

- Vibration
- Tube-to-Tubesheet Joints
- Heat Transfer/Fouling
- Hydriding/Galvanic Corrosion
- Other Corrosion and Erosion Factors

Vibration. Approximately one-half of the relatively few failures of titanium tubing are directly attributable to vibration damage.

The damage itself is manifested by: 1) fatigue failure of the tube where it passes through a support plate; or 2) flattened regions on the outside surface of the tube along its length due to collision with adjacent tubes which can cause eventual rupture.

This failure mechanism is by no means peculiar to titanium. The field survey found instances of vibration damage in admiralty, aluminum brass, and stainless steel tubing. Usually, tube vibration is caused by high shell-side cross-flow steam velocities at the top or upper sides of the tubing bundles. It also occurs adjacent to poorly baffled auxiliary dump and drain lines. An instance of tube damage by vibration in an air removal section was found during the field survey. Improper support plate spacing or steam flow distribution, or unusual condenser operating conditions are typical sources of the problem.

(NOTE: The very brief discussion of vibration that follows is intended to show only qualitative relationships. The reader is directed to the indicated references for a more complete treatment.)

The major excitation force causing condenser tube vibration results from the cross-flow steam velocity. The resulting drag force causes tubes to vibrate at their natural frequency given by the equation (235-p.165; also see 4 and 354):

$$f_n = C \left[\frac{gEI}{WL^4} \right]^{1/2}$$

Where: f_n = natural frequency
g = gravitation constant
E = modulus of elasticity
I = moment of inertia of tube cross-section
W = weight per unit length of tube filled with water
L = tube span between supports
C = end support constant

The deflection of the vibrating tube is given proportionally as:

$$Y \propto k \frac{W_D L^4}{EI}$$

Where:

Y = deflection or amplitude

W_D = (drag) force per unit length causing the deflection

k = end support constant

Also affecting the amplitude of vibration is the amount of system damping.

To avoid impact with adjacent tubes at their midspan, the tube vibration amplitude must be restricted. For a given steam flow condition (W_D), amplitude reduction may be accomplished by: 1) decreasing tube span (L); 2) increasing the modulus of elasticity (E); or 3) increasing the moment of inertia (I). The natural frequency will simultaneously increase with any of these changes as well, thus indicating an increase in tube stiffness.

Comparing titanium to the copper-base and stainless steel tubing alloys under identical conditions it is more susceptible to this type of damage because: 1) titanium has a relatively low modulus of elasticity; and 2) thinner-walled titanium tubing has a lower moment of inertia. Both of these result in a tube with higher vibration amplitudes which can be reduced by decreasing the tube span (117).

Correction for this potential problem, as it relates to titanium-tubed condensers, depends on the particular situation. When designing a new condenser for use with titanium tubes, suitably close tube support plate spacing can be provided (133). When retubing an existing condenser, a careful evaluation of the potential for vibration should be made (132). In this regard, one utility decided not to retube one of its units with titanium because of a previous history of vibration damage to copper-base alloy tubing. In a retubing situation where the possibility of vibration exists, the tubing can be staked by any of a number of methods thereby reducing the effective tube span. Finally, in the instance of locally high steam velocities, staking of the tubing or dispersion of the jetting steam can control or eliminate the problem.

Table 5-15 shows the reported data from the field survey relating to vibration in titanium tubes. The units are listed in order of increasing tube support spacing. This table shows no apparent relationship between support spacing and vibration damage. Other factors such as steam flow velocities and distribution, peculiar to each unit, also play an important role.

Table 5-15

FIELD SURVEY DATA
TITANIUM AND VIBRATION

CONDENSER*	APPROXIMATE TUBE SUPPORT SPACING, in. (cm)	TUBING STAKED	REPORTED VIBRATION FAILURES	TUBE O.D., in. (cm)	TUBE GAGE BWG
A	30 (76)	Yes** - through- out all bundles	1 tube showed No - minor wear	7/8 (2.22)	22
B	36 (91)	Yes** - at top of bundles	some on Yes- side of bundles	7/8 (2.22)	22
C	38-1/2 (98)	No	No	7/8 (2.22)	22
D	38-1/2 (98)	No	No	7/8 (2.22)	22
E	38-1/2 (98)	No	No	7/8 (2.22)	22
F	41 (104)	No	No	1 (2.54)	22
G	42 (107)	No	No	1 (2.54)	20
H	42 (107)	No	No	1 (2.54)	22
I	42 (107)	No - but will be done	Yes - some at top	1 (2.54)	22
J	51 (130)	No	No	1 (2.54)	22
K	57 (145)	Yes** - at top of bundles	Yes - numer- ous on side of bundles	1 (2.54)	22

*One of the 12 units surveyed has no titanium impingement tubes.

**Staking done at time of retubing with titanium.

Tube-to-Tubesheet Joints. In addition to the failure of the tube itself, the other potential major source of circulating water inleakage into the condenser is the tube-to-tubesheet joint. In power industry condensers, this joint is typically made by expanding the tube into the tubesheet -- forming an interference fit. Some condensers have welded or packed joints. Utility personnel interviewed during the field survey reported the incidence of detectable leakage through tube-to-tubesheet joints is very low. Either joint integrity is sufficiently good to prevent leakage or the amount of leakage is too small to be revealed by the leak detection and location methods used. For the titanium tubing included in this survey, all tube-to-tubesheet joints were made by roller expanding the tubes into single tubesheets at each end of the tubes. The British use roller expanded tubes but also have double tubesheets in some of their titanium-tubed condensers. The tubes are rolled into both tubesheets at each end (6-p.126).

Welded joints have been little used in surface condensers with titanium tubing. Some desalination (242), chemical, and refinery applications have used welded joints with titanium tubes and tubesheets. The Japanese have used such "all-titanium" installations in industrial turbine condensers (133). The British have developed a method of explosion-welding a seamless titanium tube into a tubesheet of dissimilar metal (336; 339; 235-p.81). Of principal concern when fusion-welding titanium is the maintenance of a complete inert gas atmosphere to prevent severe embrittlement from atmospheric contaminants. To date, fabricating shops have best been able to provide the required craftsmanship, equipment, and tight control of welding conditions. But present-day condensers have required field erection because of their large size. Modular construction of condensers using shop-welded joints of lighter weight titanium tubing may provide a solution to this dilemma (235-p.87; 354). Previous experience with welded joints in chemical processing plants has shown them to be strong and corrosion-free (262).

As with welded joints, joint integrity, joint strength, and material compatibility are important factors with rolled titanium joints. The integrity of a rolled joint is normally tested following installation by flooding the steam side of the condenser. Any joint found leaking is normally rerolled to seal the joint. Initial joint leakage data were obtained for 3 units in which titanium tubes were installed. Discounting tubes that were inadvertently bypassed during the rolling operation, 1 unit containing about 15,000 tubes had about 35 tubes that required rerolling. Another required rerolling of about 20 of 14,000 tubes (132). The third required rerolling of about 110 of 13,000 tubes. In the third installation, half of the tube joints had been rolled by an inexperienced boilermaker; some of the tubes had been trimmed by a method that resulted in a loosening of joints. The first 2 units have grooved, aluminum bronze tubesheets; the third unit has ungrooved muntz metal tubesheets. Because of the tendency of titanium to work-harden, rerolling of tubes must be done with care. Comparative data for other tube materials were not obtained.

The mechanical strength of the joint is measured by the amount of force required to pull the joint apart. Numerous factors affect this pullout strength including tube material, tubesheet material, size of contact area, whether the hole is grooved, original material dimensions, amount of interference fit, type of tube expander used, and workmanship. Various utilities, condenser manufacturers, tubing fabricators, and tubing installers have tested the pullout strengths of differing materials and geometries. Although no compilation of information was made, some general observations are offered:

- Grooves in the tubesheet holes will improve joint strength. A number of the titanium installations have no tubesheet grooves and are operating satisfactorily.
- Higher yield strength aluminum-bronze tubesheets provide a stronger joint than does muntz metal. About two-thirds of the surveyed units with titanium tubing had muntz metal tubesheets.

The apparent trend in new condensers designed for titanium tubing is to use aluminum-bronze or titanium-clad steel tubesheets.

A flare on the inlet end of the condenser tubes historically has been provided to reduce power-wasting turbulence and to alleviate erosion of the tubing. Since titanium has very good resistance to erosion (as described later), flaring of the tubing is not necessary to reduce erosion. To improve hydraulic performance, titanium tubes can be flared if necessary precautions are taken to avoid loosening the rolled joint or splitting the tube end. All of the field survey units except two had flared tube inlets.

Heat Transfer/Fouling. When comparing the performance of titanium to the copper-base alloys in particular, heat transfer and fouling characteristics are frequently mentioned. The copper-base alloys have a higher thermal conductivity than titanium and a natural, surface poisoning effect on biofouling organisms. Various design features are being used or proposed to enhance the thermal performance of titanium (6-pp. 127, 125; 133), as follows:

- Thinner-walled tubing, 25 BWG instead of the more typical 22 BWG, would further reduce heat transfer resistance.
- Increased tube water velocity from the normal 7-8 fps (2.2 meters per second) to 10 fps (3.0 meters per second) or higher to decrease the fouling and silting of the tubes (133; 134; 6-p.127), improve the water-side heat transfer coefficient, and, consequently, reduce the required surface area of the condenser and decrease circulating water temperature rise. Such benefits must be balanced against the additional pumping costs that result. Other factors such as water-box design and flow distribution also require careful evaluation.

The thermal performance of titanium appears to be good. Current design practices employ cleanliness ratios for titanium in the range of 85 to 100 percent -- similar to those for stainless steel tubing. The British found that although 70-30 copper-nickel tubes had an initially higher overall heat transfer coefficient than titanium, after 14 months of operation the titanium performance was better than that of copper-nickel due to lower fouling (6-pp. 127;129). The Japanese found that after 8 months of operation without tube cleaning, titanium tubing in a small, industrial, steam condenser was still performing at the original 90 percent design cleanliness (133). One installation in this country is experiencing problems in maintaining a design cleanliness of 85 percent in spite of frequent cleaning of the tubes with plugs. The fouling condition is apparently caused by a high silt concentration in the water, aggravated by the

lack of a circulating water biocide. Although quantitative data from the field surveyed units are lacking, stations retubed with titanium are experiencing comparable or slightly better thermal performance than with the previous copper-based alloy tubing.

The two principal sources of condenser tube fouling are the inorganic deposits and the deposits associated with marine and freshwater organisms. Broadly speaking, the first category contains such foulants as calcium carbonate, and muds and silts that become cemented to the tubing; the second category includes slimes, algae, barnacles, etc. Frequently they appear in a combined effect with the slime, for example, contributing to the deposition of fine, suspended solids on the exposed surfaces of the condenser and circulating water system. The buildup of corrosion products on the tube surfaces also acts to reduce heat transfer efficiency.

The traditional methods for combating fouling and maintaining condenser efficiency are to periodically (or continuously) mechanically remove the deposits, introduce biocides into the circulating water, and maintain nonscaling water conditions where such control is necessary and possible.

Of the 12 titanium-tubed units in the field survey, 8 employed the use of periodic cleaning with brushes, plugs, scrapers, sponge balls, or rods; 4 (including 3 of the 8 above) sprayed the tubing with water jets to remove accumulations; and 2 cleaned the condensers by reversing flow. All but two of the units used chlorine for the control of organic growth.

Hydriding/Galvanic Corrosion. A fourth factor relating to the use and performance of titanium is the electrical potential differences developed between titanium and other metals that can result (as explained below) in either: 1) the adsorption of atomic hydrogen onto the titanium, which may lead to hydrogen embrittlement; or 2) galvanic wastages of the dissimilar metal materials used

for tubesheets or water boxes. C. F. Hanson describes the embrittlement phenomenon (6-p.125):

Atomic hydrogen is formed on commercially pure titanium surfaces exposed in seawater when their potential falls below about - 700mV with respect to a saturated calomel electrode. Hydrogen evolution cannot occur when titanium is coupled with any or a combination of the common copper-based tube or tube plate materials,... It may occur in systems with sacrificial zinc anodes, or when impressed current cathodic protection is used. In multi-metal couples including copper-base materials as well as mild steel, the hydrogen evolution potential is not reached unless associated with either impressed current or sacrificial zinc anode cathodic protection.

*At the metal temperatures usually encountered in seawater cooled turbine condensers, surface adsorbed hydrogen atoms normally result only in discrete surface layer hydriding, which does not unduly affect the use of the material. It has previously been considered that diffusion of surface hydride layers into bulk titanium occurs only above about 80°C (6) (7).** (Diffusion of molecular hydrogen through the protective titanium oxide film is significant only at temperatures in excess of 300-350°C.)

The Japanese have reported adsorption of hydrogen and hydriding of the titanium below the surface of the tubes after 1 to 2 years of operation in surface condensers (135). The titanium was used in the air removal sections of otherwise aluminum-brass-tubed condensers using uncoated naval brass tubesheets. Ferrous ion was injected and impressed current cathodic protection was provided. The reported hydriding occurred on the inside surface in the first 2.4 inches (60 mm) of length from each end of the tubes to a maximum depth of about 0.025 inch (≈0.1 mm). The amount increased toward the ends, and the outlet end experienced a higher hydrogen adsorption than the inlet end. No failures of the titanium were reported.

Although details are lacking, the field survey of one titanium-tubed unit revealed a case of subsurface hydriding on the outside of a tube at (or very near) a support plate location. The tube had been removed for inspection following failure by vibration-induced collision damage and laboratory analysis revealed hydriding. It is not known whether the hydrogen contamination occurred before or after installation in the condenser.

* (6) Cotton, J. B., The Science, Technology and Application of Titanium, Pergamon Press, 1970, 155.

(7) Charlot, L.A., et al. OSW Research and Development, Report No. 624, 1970.

TIMET (127) has investigated the embrittlement phenomenon in the laboratory by cathodically charging a variety of titanium samples in a synthetic sea salt solution at ambient temperatures. In addition, samples of test titanium tubing from in-service condensers were removed for examination. Their findings are summarized below:

It appears to be very difficult to charge hydrogen into titanium or even to form a surface hydride layer at ambient temperature in a neutral pH solution. Power plant surface condensers operate at a temperature of about 40°C. At this low temperature, it seems highly unlikely that hydrogen embrittlement of the titanium tubes would occur even if cathodic protection did form a hydride film on the surface. Jacobs and McMaster (5) claim that no appreciable diffusion of hydrogen in titanium occurs at temperatures below 70°C.*

Laboratory tests indicate that it is highly unlikely that hydrogen embrittlement of titanium surface condenser tubes will occur under normal operating conditions. These findings are supported by the independent published work of other investigators.

Examination of titanium tubes after years of service in polluted seawater under cathodic protection support this conclusion. No evidence of hydrides or deterioration of mechanical properties could be detected.

Anodizing the surfaces of titanium tubing (electrolytically increasing the oxide thickness) is used in refinery applications where the material is exposed to higher temperature hydrogen environments. But where sufficient water is present to maintain passivity as in steam condenser service, anodizing does not appear to provide any additional protection (117).

Titanium is cathodic to all alloys typically used for condenser tubesheets and water boxes. Its use in a condenser increases the normal uncoupled corrosion rate of any dissimilar metal used in such services. Some likelihood for galvanic corrosion exists for any dissimilar metal couple in condensers. But the likelihood is higher with titanium because reducing reactions with oxygen and hydrogen occur more readily on titanium.

*(5) Bibliography reference 117 of this report.

The Japanese have reported galvanic attack of naval brass tubesheets both with and without titanium tubing in the air removal sections of condensers. Impressed current cathodic protection was used to control the galvanic attack but hydriding of the titanium reportedly occurred. The addition of ferrous ion significantly reduced the galvanic corrosion (135). Other work (133) indicates that titanium and naval brass can be used together without hydriding or galvanic attack if the cathodic protection potential is carefully controlled.

The use of coatings and more galvanically compatible materials (i.e., aluminum bronze tubesheets) have also been suggested to provide protection of materials coupled with titanium (6-pp.126-127).

The above discussion indicates that impressed current cathodic protection systems must be well controlled when used with titanium. Table 5-16 tabulates the data relative to the "galvanic environment" in those condensers tubed with titanium which were included in the field survey.

Other Corrosion and Erosion Factors. The following is a general summary of the literature relevant to the susceptibility and resistance of titanium to corrosion and erosion:

- "The protective oxide film on titanium is maintained in seawater at least up to 130°C metal temperature irrespective of oxygen, sulphide, or ammonia content and under crevice conditions arising from scaling, biofouling, or local tube blockage" (6-p.124).
- "...commercially pure titanium does not suffer crevice attack in seawater or in brine at temperatures up to 130°C... An increase in chloride from 3% to 6% does not alter that situation. Neither does normal fluctuation in the pH value of seawater, provided that the pH level remains above a figure of about 3" (6-pp. 121-122). Similarly, pitting corrosion does not affect the material below about 250°C in seawater conditions (117;212; 347).
- "It is immune to stress corrosion, corrosion fatigue and fretting corrosion in polluted cooling waters and in high purity chloride contaminated or ammoniated steam" (6-p. 124).
- Due to titanium's extremely low corrosion rate in a variety of condenser cooling waters and the nontoxic nature of the metal and its passivating oxide (TiO_2), there exist no potential adverse environmental effects due to its use in cooling water systems.*

*"Titanium Tubing, Bulletin SC-3," p.13.

Table 5-16

FIELD SURVEY DATA
TITANIUM AND ITS GALVANIC ENVIRONMENT

CONDENSER	TUBESHEET MATERIAL/COATING	WATERBOX MATERIAL/COATING	CATHODIC PROTECTION	REPORTED GALVANIC ATTACK * **	REPORTED TITANIUM HYDRIDING*
A	Muntz/none	2% Ni-Ci/none	Impressed current	No	No
B	Muntz/none	2% Ni-Ci/none	Impressed current	No	No
C	Muntz/none	Ci/none	Impressed current	No	No
D	Muntz/none	steel/gunnite	Impressed current	No	No
E	Muntz/none	steel/gunnite	Impressed current	No	No
F	AlBronze/none	steel/carbomastic	Sacrificial-zinc	No	No
G	90-10 Cu-Ni/epoxy	steel/epoxy	Sacrificial-zinc	No	Yes - 1 tube from steamside
H	Muntz/none	inlet: steel/ fiberglass outlet: Ci/none	Sacrificial-mg	Slight on tubesheet	No
I	AlBronze/none	AlBronze/none	Sacrificial-zinc (discontinued shortly after TI installation)	No	No
J	Muntz/none	inlet: none 2% outlet: coal Ni-Ci tar epoxy, bitumastic	None	No	No
K	Muntz/none	steel/coal tar epoxy	None	No	No
L	Muntz/none	Ci/none	None-low TDS water	No	No

*Subjective data; e.g., most stations have not specifically checked for hydriding; no inspection of tubesheets, water boxes, or tubing were made during the survey.

**Severe galvanic attack occurred on some tubesheets prior to the installation of the titanium tubing. The responses here only apply since the installation of titanium.

- Similarly, the steam-side corrosion resistance of titanium results in minimal metal ion carryover to downstream steam generating equipment. For BWR applications, the daughter products due to any titanium carryover to the reactor have very low half lives.*
- Titanium is not adversely affected by conventional acid cleaning cycles where it may be installed in mixed material plant designs with iron or copper-base alloys requiring acid cleaning.** ***
- Titanium is resistant to erosion in clean seawater at velocities up to about 65 fps (20 m/sec); with high sand content water, the erosion threshold is about 20 fps (6 m/sec) (6-p.122). Localized tube blockages do not cause erosion attack at normal design velocities up to 11.5 fps (3.5 m/sec) (6-p.124).
- Sato (235-p.265) has indicated that some difficulties may exist with hydrogen attack from the steam side of BWR units and a probability for crevice corrosion under heavy water-side deposits. The second point is also brought out by Jacobs and McMaster (117) that if a solid chloride salt deposit forms on the titanium surface, the concentrating and insulating effect of the deposit may increase the surface temperature ("hot wall effect") and salt concentration sufficiently to cause pitting.

SUMMARY OF PERFORMANCE

The data previously presented in this section under the individual material headings will now be brought together for comparative analysis. It has been developed earlier in this report, and also by other investigators, that the service life of condenser tubes is markedly affected by the composition of the cooling water. Accordingly, separate comparisons will be made for each of the three broad cooling water categories used in this study.

Fresh Water

Condensers cooled once-through by fresh water experience significantly less tube deterioration than do condensers cooled by brackish water or seawater. This is illustrated by the overall field survey data. The 108 tubesets of all materials in main-body service in fresh water had a median total failure rate of 0.021. The 129 tubesets of all materials in main-body service in salt water had a median failure rate of 0.30 -- a fifteenfold increase over that for fresh water.

*Ibid, p.14.

**Ibid, p.16.

*** "Titanium Tubes for Refinery Heat Exchangers, Bulletin RT-1," Titanium Metals Corporation of America, November 1975, p.21.

A comparative summary of tube deterioration measurements for the principal condenser tube materials used in fresh water is given in Table 5-17. The data base for each category of material and service is described by the number of stations, generating units, and tubesets for which failure rates could be calculated. In main-body service, the broadest data base is for admiralty; SS-304 is intermediate; and 90-10 Cu-Ni has the narrowest base with all data from a single station. In air removal service, an adequate data base was obtained only for admiralty and SS-304.

Main-Body Service. The tube deterioration parameters listed in Table 5-17 indicate that in the main condensing body of freshwater cooled condensers, admiralty, SS-304, and 90-10 Cu-Ni all give acceptable service life. There is no outstanding difference among them; the variations in the tabulated values are small enough to be less than the probable error of the stated values. For all three materials the probability (calculated from the respective data bases) is greater than 90 percent that the total failure rate due to all causes will not exceed 0.333. This corresponds to the failure rate that would result if 10 percent of the tubes failed after 40 years of service or if 5 percent failed after 20 years. The calculations for SS-304 were adjusted as noted in Table 5-17. Other data bases were not adjusted similarly because the number of guard plugs present was insufficient to dominate the calculation and cause a possibly misleading result.

It is noteworthy that of the 108 tubesets in main-body service, only two (1.85 percent) have been replaced. The two replaced tubesets were parallel bundles in the same condenser.

Although the anticipated service life of the principal condenser tube alloys in freshwater service may be approximately equal, the selection of tube material for any specific application must carefully consider numerous other factors. In addition to such ordinary concerns as heat transfer capability, tubing availability, economics, etc, there has been a recent concern about the release of copper and other metals from the condenser tubes to the condensate, and the impact of the released metals on the turbine cycle equipment downstream of the condenser. Evaluation of the release of metals from the condenser tubes to the condensate was not a part of this study.

Table 5-17

COMPARATIVE PERFORMANCE OF CONDENSER TUBE MATERIALS
IN OPEN FRESHWATER COOLING SYSTEMS

SERVICE	MATERIAL	NUMBER OF			TUBESETS REPLACED		MEDIAN TOTAL FAILURE RATE	PROBABILITY, %	
		STATIONS	UNITS	TUBESETS	NUMBER	PERCENT		40YR - 10% FR <0.333	30YR - 5% FR <0.222
Main Body	Admiralty	14	25	66	2	3.0	0.031	91	88
Main Body	90-10 Cu-Ni	1	2	16	0	0	0.045	100	81
Main Body	SS-304	5	6	26	0	0	0.000*	96*	96*
Air Removal	Admiralty	5	9	34	20	58.8	3.398	27	15
Air Removal	90-10 Cu-Ni	1	2	4	0	0	**	**	**
Air Removal	SS-304	9	14	42	0	0	0	93	93
Air Removal	SS-316	1	1	4	0	0	0	**	**
Air Removal	Titanium	1	1	4	0	0	0	**	**

*These values have been adjusted by the elimination of numerous guard plugs installed in four tubesets at one station. The raw data values are: Median Failure Rate = 0.003, 40yr - 10% probability = 80.8%, 30yr - 5% probability = 80.8%.

**There are not sufficient values in the data base to allow a meaningful calculation to be made.

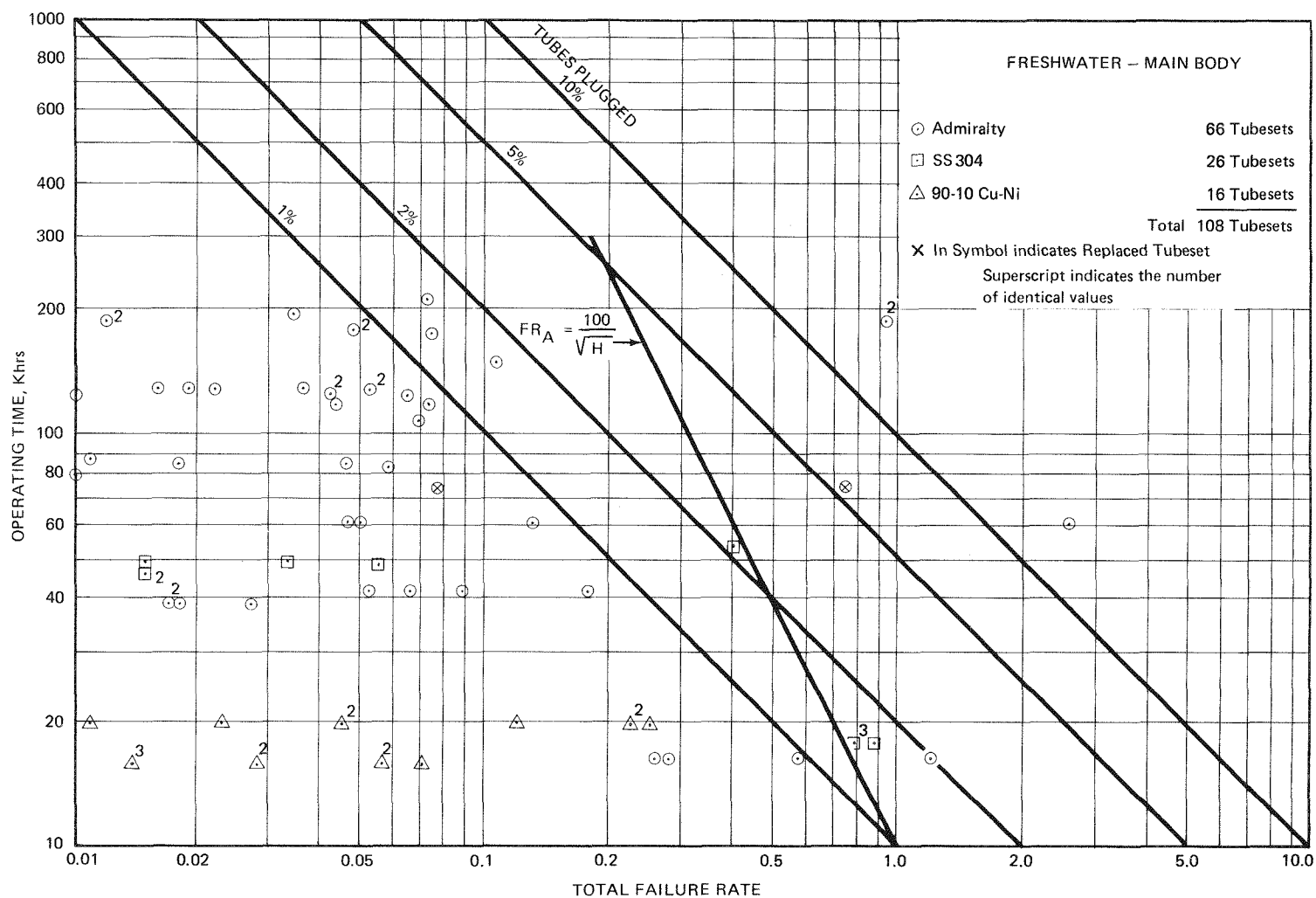
Figure 5-12 is a plot of the total failure rate versus the operating time for the tubesets in main-body service in freshwater cooled condensers. The material is designated by the indicated symbol. Twenty admiralty tubesets and 16 SS-304 tubesets had failure rates less than 0.01 and are not shown on the plot. The only value plotted for each tubeset is the cumulative total failure rate (all causes) for the total operating hours of the tubeset at or near the date of the field survey. Examination of Figure 5-12 shows no correlation between the attained failure rate and the age of the individual tubeset for any of the three tube materials.

To place this observation in proper perspective it should be recalled that the total failure rate is calculated from the number of plugged tubes in the condenser without regard to why the tubes were plugged. It includes guard plugs deliberately placed in tubes that had not failed at the time. While it is a practical measure of condenser tube serviceability because condenser performance and maintenance costs relate to the number of tubes plugged and not to the reason for their plugging, it does not indicate, in any way, the failure mechanism. The failure rate due to some mechanisms such as electrochemical corrosion would be expected to increase exponentially with time. The lack of a correlation between the attained total failure rate and the tubeset service life suggests that no one failure mechanism is dominant overall. Apparently, the net effect of all failure mechanisms working together is independent of time when a large body of actual historical data is considered as is done in Figure 5-12.

It was also found that no overall correlation existed when the total failure rates (FR) for the individual tubesets were plotted against the selected time increments (Field Survey Matrix columns 117 through 124) up to the attained service life (only these last points are shown in Figure 5-12). Also, no overall correlation was found when the available data for failure rate on the water-side (FRW) was plotted against time. (These data are given in the Field Survey Matrix columns 93 through 100.)

The line labeled $FR_A = 100/\sqrt{H}$ is a criterion for judging if a given tubeset is a candidate for replacement. It is discussed on page 5-66.

Air Removal Service. As shown in Table 5-17 for the tubes in air removal service, an adequate data base was obtained for admiralty and SS-304 only.



G1001892-31

Figure 5-12. Failure Rate vs Operating Time for Main-Body Tubesets in Fresh Water

The tabulated performance criteria indicate that admiralty gives unsatisfactory service in the air removal section of freshwater cooled condensers. For the 34 tubesets surveyed, the median failure rate was 3.398. Nearly 59 percent of the tubesets have been replaced. The dominant failure mode apparently was steam-side failures induced by ammonia.

In the air removal section, SS-304 gives very acceptable performance. All of the 42 tubesets surveyed are still in service with a median failure rate of zero. Based on these data there is a 93 percent probability that SS-304 in air removal sections will serve 40 years with less than 10 percent of the tubes plugged.

Salt Water

In Table 5-18 the comparative summary of the measures of tube deterioration are given for the principal materials used in condensers cooled once-through by salt or brackish water.

Main-Body Service. In this service a reasonably adequate data base was obtained for aluminum brass, 90-10 Cu-Ni, and titanium. Lesser data bases were obtained for 70-30 Cu-Ni and aluminum bronze. Viewing the main-body data as a whole it appears that the aluminum brass, aluminum bronze, and 90-10 Cu-Ni will not last the plant's lifetime.

Based on the survey data, all three alloys have a 50 percent or less probability of attaining a failure rate less than 0.33 (40 years with less than 10 percent of the tubes plugged). There is a 40 percent or less probability that the failure rate will be less than 0.222 which corresponds to 30 years service with less than 5 percent of the tubes plugged. Of the surveyed tubesets, a high proportion had been replaced: 45 percent of the 90-10 Cu-Ni, 60 percent of the aluminum brass, and 67 percent of the aluminum bronze.

The data base obtained for 70-30 Cu-Ni consisted of only 6 tubesets in main body service, which is inadequate to establish a meaningful trend. The very limited data on 70-30 Cu-Ni indicate a somewhat better performance than that for aluminum brass, aluminum bronze, and 90-10 Cu-Ni.

Table 5-18

COMPARATIVE PERFORMANCE OF CONDENSER TUBE MATERIALS
IN OPEN SALT-WATER COOLING SYSTEMS

SERVICE	MATERIAL	NUMBER OF			TUBESETS REPLACED		MEDIAN TOTAL FAILURE RATE	PROBABILITY, %	
		STATIONS	UNITS	TUBESETS	NUMBER	PERCENT		40YR - 10% FR <0.333	30YR - 5% FR <0.222
Main Body	Alum. Bronze	2	3	12	8	66.7	1.880	33	33
Main Body	Alum. Brass	6	11	35	21	60.0	0.333	50	40
Main Body	90-10 Cu-Ni	7	16	55	25	45.5	0.613	40	29
Main Body	70-30 Cu-Ni	2	2	6	2	33.3	0.102	67	67
Main Body	Titanium	8	11	21	0	0	0.003	91	91
Air Removal	70-30 Cu-Ni	5	11	45	8	17.8	0.060	69	62
Air Removal	Titanium	1	1	2	0	0	0.000	*	*

*There are not sufficient values in the data base to allow a meaningful calculation to be made.

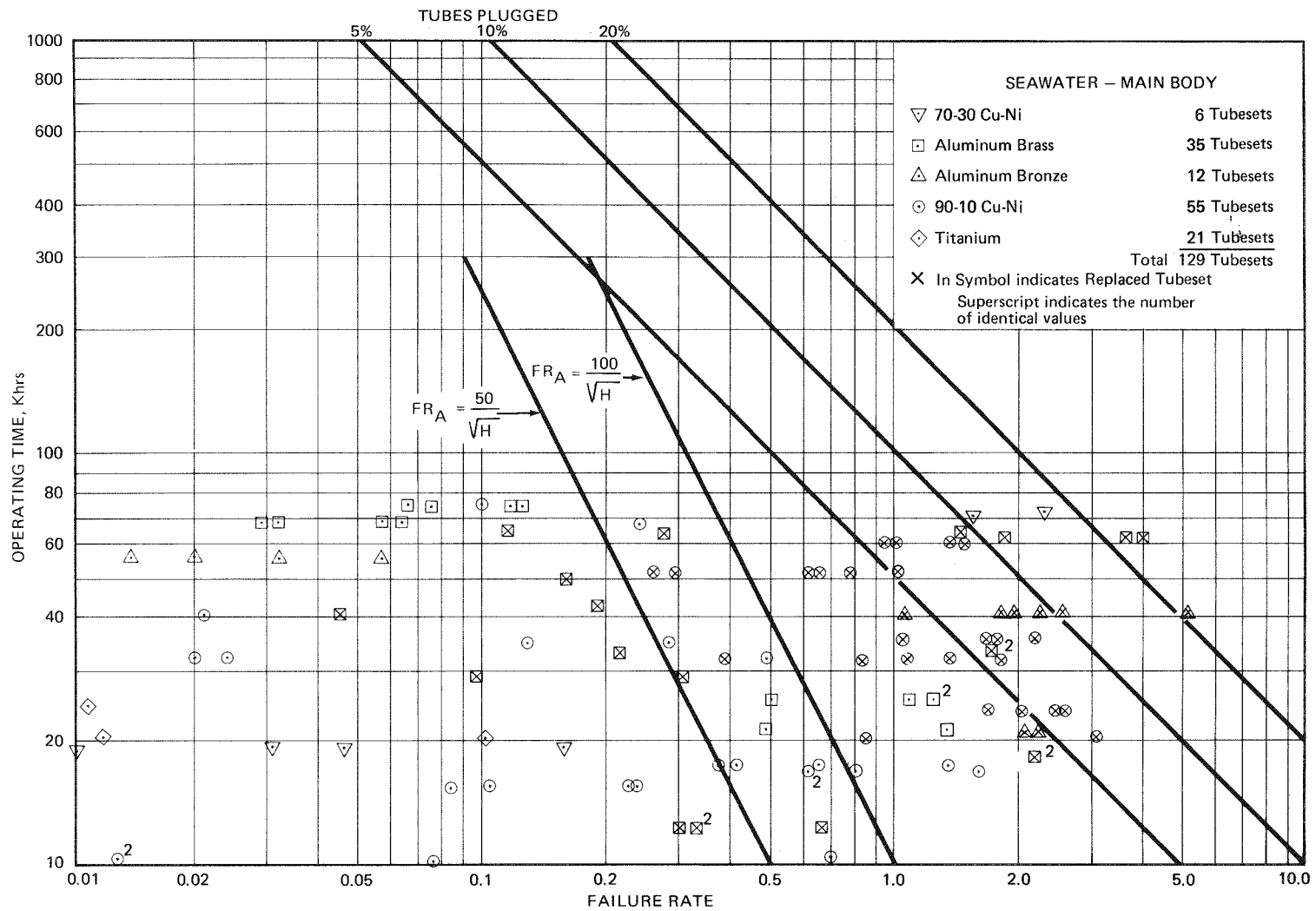
The data base for titanium tubes in main-body service in condensers cooled once-through by brackish water or seawater comprised 21 tubesets. As previously stated, nearly all United States power stations with a significant number of titanium condenser tubes were included in the survey hence the data base is nearly the sum of experience in the United States. As shown in Table 5-18, titanium gives excellent service in seawater service. The calculated probability is 91 percent that the failure rate will be less than 0.333 (40 years with less than 10 percent plugs). This probability would be higher (approaching 99 percent) if it were not for a number of vibration failures (and affiliated guard plugs) at one station where the titanium tubes were installed as replacements in an existing condenser.

The median failure rate for the titanium data base was 0.003. As pointed out in the discussion of titanium in this section of the report, the oldest titanium tubesets are only 5 years old. Prudent judgment should be exercised in the application of the implied extrapolations given by the probability calculation interpretations.

Total failure rates versus the operating time to the survey date are plotted in Figure 5-13 for all surveyed tubesets in main-body service in condensers cooled once-through by salt or brackish water. The material is designated by the indicated symbol. An X through the material symbol indicates that the tubeset has been replaced.

As was the case for fresh water (Figure 5-12), there is no discernible correlation between the total failure rate attained as of the survey date and the age of the tubeset. The comments on this observation given in the discussion of Figure 5-12 are applicable here also.

Examination of Figure 5-13 allows insight as to when the industry deems it desirable to replace the tubes in a failing condenser. Nearly all of the replaced tubesets had an attained failure rate greater than 0.222 at the time of replacement. Of replaced tubesets that had a failure rate less than 0.222, several were in condensers where other tubesets had a failure rate greater than 0.222 and the entire condenser was retubed. Most of the replaced tubesets had a failure rate greater than 0.333 at the time of replacement. Note that nearly



G1001892-30

Figure 5-13. Failure Rate vs Operating Time for Main-Body Tubesets in Seawater

all of the replaced tubesets had more than 1 percent of the tubes plugged, and most had more than 2 percent plugged. About half of the replaced tubesets had 5 percent or more plugged tubes but only a few had more than 10 percent of the tubes plugged. However, the attained failure rate at the time for replacement is not an adequate criterion for tracking the performance of an in-service tubeset. For example: Early in the life of a tubeset a number of tube failures could be experienced due to vibration or due to a missile. The calculated failure rate would be high due to the short operating time even though the percentage of the tubes plugged was less than 2 percent. After correction of the mechanical problem the calculated failure rate would decrease as the operating hours increase with few, if any, additional failed tubes. Hence a more valid criterion for assessment of the performance of an in-service tubeset would be a variable failure rate. The "allowable" failure rate would decrease as the service life of the tubeset increased. A line that accomplishes this is drawn in Figure 5-13. The equation of the plotted line is:

$$FR_A = \frac{100}{\sqrt{H}}$$

Where FR_A = allowable failure rate

H = total operating hours for the tubeset

The equation of the line can also be expressed as:

$$\%P_A = \frac{\sqrt{H}}{100}$$

Where $\%P_A$ = allowable % tubes plugged

H = total operating hours for the tubeset

This line was fitted with the intent that failure rates lying to the right of it would be candidates for replacement while failure rates to the left of the line would indicate a high probability that the replaced tubeset would serve the plant's lifetime. In Figure 5-13, 72 percent of the tubesets lie to the right of the line, and 28 percent lie to the left. Recall, however, that about half of the replaced tubesets to the left were in condensers with other tubesets that were to the right of the line.

A more conservative criterion can be obtained by multiplying the calculated allowable failure rate by an appropriate factor. For example: If the calculated FR_A is multiplied by 0.5 then 85 percent of the failed tubesets in Figure 5-13 would be to the right of the more conservative line. All of the tubesets remaining on the left are in condensers with other tubesets to the right. The equation of the conservative line is $FR_A = 50 / \sqrt{H}$.

The use of either equation provides a simple and rapid method for tracking the performance of existing condenser tubesets based on the cumulative data obtained during this study.

Plant management can readily determine when the tubeset is a candidate for replacement by comparing the attained failure rate with the allowable failure rate.

Air Removal Service. The only material in air removal service in salt-water-cooled condensers for which an adequate base was obtained was 70-30 Cu-Ni. The field survey included 42 tubesets of 70-30 Cu-Ni. The median failure rate was 0.060. Nearly 18 percent of the tubesets had been replaced. The calculated probability of attaining a failure rate less than 0.333 (40 years, 10 percent) was 69 percent.

Closed Cooling-Water Systems

The comparative summary of the measures of tube deterioration for condenser tubes in closed cooling-water systems is given in Table 5-19. All of the closed systems included in the survey used fresh water for cooling tower makeup.

The data base for all materials is small. Accordingly, the indicated performance parameters have limited reliability. There is an indication that admiralty in main body service gives much poorer performance in a closed cooling system than it does in a freshwater once-through cooling system. On the basis of the limited sample, SS-304 in main body service appears to perform as well in a closed cooling-water system as it does in a freshwater once-through system.

In the air removal section of condensers with closed cooling-water systems, 70-30 Cu-Ni appears to give very acceptable service. Here again, the data base is quite limited.

Table 5-19

COMPARATIVE PERFORMANCE OF CONDENSER TUBE MATERIALS
IN CLOSED COOLING-WATER SYSTEMS

SERVICE	MATERIAL	NUMBER OF			TUBESETS REPLACED		MEDIAN TOTAL FAILURE RATE	PROBABILITY, %	
		STATIONS	UNITS	TUBESETS	NUMBER	PERCENT		40YR - 10% FR <0.333	30YR - 5% FR <0.222
Main Body	Admiralty	3	6	16	2	12.5	0.135	56	56
Main Body	SS-304	2	3	9	0	0	0.107	89	89
Air Removal	70-30 Cu-Ni	2	2	10	0	0	0.0	90	90
Air Removal	90-10 Cu-Ni	1	2	4	0	0	3.376	*	*
Air Removal	SS-304	2	5	8	-	-	*	*	*

*There are not sufficient values in the data base to allow a meaningful calculation to be made.

Section 6

CONCLUSIONS

The conclusions listed in this section are derived from an objective evaluation of the findings of this study. They are based primarily on the data obtained by the field survey but they also reflect the findings of the mail survey and the literature search. Other information sources can be expected to produce specific exceptions to these conclusions, but because of the methodology used in the selection of the field survey samples (Section 3) and the size of the sample (76 generating units at 30 stations), these conclusions should be representative of condenser related experience at large, modern power stations in the U.S.

PERFORMANCE OF CONDENSER TUBE MATERIALS

Fresh Water

1. In the main condensing section of condensers cooled by fresh water in a once-through mode, all of the commonly used condenser tube materials give acceptable service. This has been shown in Table 5-17 which summarizes the performance data collected by the field survey for admiralty, 90-10 Cu-Ni (Alloy 706), and Type 304 stainless steel. For these materials there is a better than 90 percent probability that the total failure rate will not exceed 0.333 which corresponds to 10 percent of the tubes plugged after 40 years of service or 5 percent plugged after 20 years.
2. Complete retubing of freshwater cooled condensers is seldom required. Only 2 of 108 (1.85 percent) tubesets in main body, freshwater service have been retubed (Table 5-17).
3. In the condensing section of freshwater cooled condensers, the failure rate from all causes (plugged tubes for whatever reason) does not correlate with the age of the individual tubeset (see Figure 5-12).

4. In the air removal section of condensers cooled by the once-through flow of fresh water, some severely high failure rates have been encountered when admiralty tubes have been used. In this service, the probability that admiralty will have a total failure rate less than 0.333 (10 percent plugs in 40 years) is only 26.5 percent (Table 5-17). The apparent reason for this poor performance is the presence of ammonia.
5. In the air removal section of freshwater cooled condensers, SS-304 has a 96.2 percent probability of serving 40 years with less than 10 percent failures (Table 5-17).
6. In the air removal section also, no correlation can be made between the failure rate from all causes and the age of the tubeset.
7. Insufficient data were gathered to allow an evaluation of 90-10 Cu-Ni tubing in air removal section service.

Cooling Towers and Ponds

8. The very limited data bank for closed cooling-water cycle condensers does not allow formulation of valid conclusions. The available data indicate that in the condensing section admiralty may have a lessened service life as compared to open cycle freshwater applications. Type 304 stainless steel performs almost as well in closed cooling water cycles as in fresh water (see Table 5-19).

Salt Water

9. Until recently, the traditional condenser tube alloys used in the condensing section of saltwater cooled condensers were aluminum brass and aluminum bronze. Neither alloy can be expected to last the plant lifetime without retubing. The probability of 40 years service with less than 10 percent tube failures is 33.3 percent for aluminum brass and 50 percent for aluminum bronze (see Table 5-18).
10. Alloy 706 (90-10 Cu-Ni) has been used in the condensing section of saltwater cooled condensers in recent years. Its anticipated service life is about the same as for aluminum brass/bronze alloys. The probability that 90-10 Cu-Ni will serve 40 years with less than 10 percent tube failures is 40 percent (see Table 5-18).

11. Titanium, the newest condenser tube material, is the only material included in this survey that can be expected to last the plant lifetime in the condensing section of saltwater cooled condensers. Titanium was found to have a 90 percent probability of lasting 40 years with less than 10 percent tube failures. This probability would be nearly 100 percent if it were not for guard plugs placed in 2 tubesets that were experiencing vibration problems.
12. All of the actual failures of titanium tubes were attributable to mechanical causes, predominantly vibration. Not one instance of corrosion or erosion failure was found during the field survey.
13. In air removal service in saltwater cooled condensers, a significant data base was generated for only 70-30 Cu-Ni. In such service, 70-30 Cu-Ni has a 69 percent probability of serving 40 years with less than 10 percent tube failures (see Table 5-18).
14. In saltwater service (as in freshwater service), there is no correlation between the total failure rate from all causes and the age of the tubeset (see Figure 5-13).

CONDENSER RETUBING CRITERIA

1. No single criterion can be expected to define the time when tubes in a failing condenser should be replaced.
2. The primary considerations in the decision to retube relate to the cost of repairing the leaks as they occur, and to the attendant loss in the reliability and full availability of the generating unit. The possibility of damage to other components in the turbine cycle must also be evaluated.
3. From the data accumulated during this study a numerical criterion has been derived to indicate when the condenser is a candidate for retubing. The criterion reflects the historical judgment and practice of the industry. When the actual failure rate (FR) exceeds the allowable failure rate (FR_A) it is likely that the condenser should be retubed. The final decision to retube must also consider the factors described in 2. above. The equation empirically derived for allowable failure rate is:

$$FR_A = \frac{100}{\sqrt{H}}$$

where, H = total operating hours for the existing condenser tubes

FR_A = allowable failure rate

This can also be expressed as:

$$\%P_A = \frac{\sqrt{H}}{100}$$

where, $\%P_A$ = allowable percent of condenser tubes plugged

The actual failure rate FR_T is calculated as follows:

$$FR_T = \frac{P/N \times 10^6}{H}$$

where, P = number of tubes plugged

N = number of tubes in tubeset

IMPACT OF CONDENSER LEAKAGE

1. At the generating units surveyed there was no demonstrated case of severe physical damage to any of the other components in the turbine cycle as a result of condenser inleakage.
2. At at least one station, the possibility that condenser inleakage was contributory to serious damage to the steam generator tubes is still under consideration.
3. The major impact of condenser tube leakage is the value of the power generation lost while the unit is operated at reduced load or is out of service.
4. No generally applicable cost figures can be assigned. The costs vary widely at the different utility systems largely because of variations in the value of the generation lost during repair operations.
5. A condenser with failing tubes can have an unacceptable impact on the availability and reliability of the generating unit.

6. The loss of condenser surface area due to plugged tubes does not have a major impact on the turbine capability. Calculations for a typical fossil-fueled power plant with a 720 MWe turbine show the following:

<u>Tubes Plugged</u>	<u>Reduction in Turbine Output</u>
1%	50 kW or 0.007%
2%	100 kW or 0.014%
5%	250 kW or 0.035%
10%	540 kW or 0.075%

DETECTION AND LOCATION OF CONDENSER LEAKS

1. All plants surveyed can detect any condenser leak large enough to be of consequence to plant operation by analysis of the condensate and steam generator blowdown.
2. Most plants have automatic analyzers to monitor turbine cycle chemistry which will respond adequately to condenser leaks of consequence.
3. The actual leak size that can be detected depends upon the quality of the circulating water. Sea water cooled plants can detect leaks of a few tenths of a gpm. Plants with low dissolved solids in the circulating water may not be able to detect a leak smaller than 10 gpm.
4. Detection methods (especially for plants with high TDS circulating water) are usually more sensitive than methods for locating the leak within the condenser. However, all plants can locate any leak large enough to be of consequence to continued plant operation.
5. There is general agreement at the surveyed stations that the most sensitive method for leak location is to hydrotest the condenser on the steam side.
6. For on-line location of condenser leaks two of the methods reported to be more sensitive are the spreading of either plastic sheets or foam over the tubesheet of the open water box. There is no general agreement as to which method is the most sensitive.

Section 7

RECOMMENDATIONS

The recommendations drawn from the findings and conclusions of this study are presented in three groups based on the time period recommended to accomplish the work: immediate short-term work; middle-term work; and long-term work.

SHORT-TERM WORK

1. Gather and evaluate additional data to enable a better assessment to be made of the performance of 90-10 Cu-Ni in the main body of condensers cooled by once-through fresh water and, most importantly, in condensers cooled by closed cooling water systems.
3. Make quantitative investigations of the copper pickup in the condensate from condensers tubed with the copper alloys. These data are urgently needed because of the current concern about the role of copper in the failure of Inconel tubes in PWR steam generators. The data are also important relevant to copper deposition in fossil-fueled boilers.
3. Develop a program to promote rigorous design standards for impingement baffles in condensers. Far too many condenser tube leaks, especially the larger ones, are caused by failed baffles that either sever the tubes directly or allow their rapid failure due to steam impingement.
4. Investigate methods to reduce the number of drain, dump, etc, penetrations into condensers and thereby reduce the need for impingement baffles. Present-day condensers have 100 or more penetrations, each of which is also a potential source of air inleakage.
5. Develop and promulgate a standard tube descriptor or numbering system for condenser tubes.

6. Further investigate the frequency and size of leaks at the tube-to-tube-sheet joint. The plants surveyed in this study reported few such leaks. Joint leaks are usually small in size and precise location techniques are cumbersome and time consuming. The need for improved joining methods can be better assessed if more specific data are available.
7. Further investigate the role of condenser design parameters as a cause of condenser leaks. This survey did not produce sufficient data on the specific cause of leaks to permit evaluation of the effect, if any, of the shell, tubesheet, and water box configurations, the tube support plate spacing, the strength of tube joints, and the design of expansion joints.
8. Additional evaluation is desirable on the cost effectiveness of such techniques for possible reduction of condenser inleakage as double tubesheets and welded tube joints.
9. Begin Phase I of the long-term investigation.

MIDDLE-TERM WORK

10. Develop and promulgate a manual on proper record-keeping relative to condenser performance that would include standardized log sheets and other appropriate forms.
11. Initiate a study on the reduction of penetrations to the condenser. Perhaps a separate drain/flash tank should be provided for all dump, drain, etc, lines which would have a single large connection to the condenser. The condenser shell should not be used as a piping manifold to the extent that it presently is.
12. Complete Phase II of the proposed long-term study.

LONG-TERM STUDY

13. The present study clearly indicates the need for a continuing long-term (10 years, or more) study of the general subject area included in this report. As indicated in the report, the data base obtained in the course of the brief field survey program was inadequate to enable definitive evaluation of some condenser tube alloys in certain environments. Also, it was found to be next to impossible to

reconstruct the data and events surrounding leakage after the occurrence even when the requisite data were in the plant archives. The data obtained on the frequency, size, and duration of condenser leaks were quite limited.

The obvious solution is a self-sustaining program which would capture and report the necessary data at the time of the incident, recording such data as leak size, subsequent impact, cost of repair, and causative mechanism. Clearly, such a program should place major emphasis on seawater-cooled stations since this is "where the action is." The program should be designed to enable plant personnel to report data on a semiannual basis. The task would be simplified by the use of standard forms to be completed routinely and problem alert forms for special incidents. The incoming data would be entered in a computerized data bank on receipt. The accumulated data would be analyzed and reported at annual intervals. The evaluation, design, and implementation of the program would be in three phases. Each phase is described below by a listing of the principal tasks that would constitute the phase.

Phase I. Feasibility and Cost Effectiveness

- a. Establish the data to be collected.
- b. Devise preliminary forms for data collection.
- c. Determine mode and extent of data manipulation and reports to be prepared.
- d. Make cost estimates of the startup cost and the annual operating cost for the program.
- e. Determine if program is feasible and cost-beneficial. If not, abandon.

Phase II. Program Design

- a. Prepare detailed data forms, etc.
- b. Devise necessary computer programs.
- c. Prepare conservative estimate of project costs.
- d. Prepare preliminary list of survey stations.
- e. Prepare detailed instructions for station participation.

Phase III. Implementation

- a. Select and organize responsible agency.
- b. Prepare final station survey list (~100 stations).
- c. Complete program design details.
- d. Collect available initial data and load into computer.
- e. Distribute field forms to participating stations.
- f. Enter data semiannually.
- g. Prepare annual reports.
- h. Review progress each year and adjust program accordingly.