MARTIN MARIETTA ENERGY SYSTEMS LIBRARIES
3 4456 0063985 1

ORNL/TM-10023

ornl

OAK RIDGE
NATIONAL
LABORATORY

MARTIN MARIETTA

Coal-Fired Electric Power Plant Life Extension: An Overview

M. J. Taylor
L. C. Fuller

OAK RIDGE NATIONAL LABORATORY
CENTRAL RESEARCH LIBRARY
CIRCULATION SECTION
4500N ROOM 175
LIBRARY LOAN COPY
DO NOT TRANSFER TO ANOTHER PERSON
If you wish someone else to see this report, send in name with report and the library will arrange a loan.

OPERATED BY
MARTIN MARIETTA ENERGY SYSTEMS, INC.
FOR THE UNITED STATES
DEPARTMENT OF ENERGY

Printed in the United States of America. Available from
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road, Springfield, Virginia 22161
NTIS price codes—Printed Copy: A06 Microfiche A01

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.

ORNL/TM-10023

Engineering Technology Division

COAL-FIRED ELECTRIC POWER PLANT LIFE EXTENSION: AN OVERVIEW

M. J. Taylor
L. C. Fuller

Date Published - July 1986

This document contains information of a preliminary nature. It is subject to revision or correction and therefore does not represent a final report.

Prepared by the
OAK RIDGE NATIONAL LABORATORY
Oak Ridge, Tennessee 37831
operated by
MARTIN MARIETTA ENERGY SYSTEMS, INC.
for the
U.S. DEPARTMENT OF ENERGY
under Contract No. DE-AC05-84OR21400

MARTIN MARIETTA ENERGY SYSTEMS LIBRARIES
3 4456 0063985 1

CONTENTS

Page

LIST OF FIGURES v
LIST OF TABLES ix
ACKNOWLEDGMENTS xi
ABSTRACT 1
1. INTRODUCTION 1
2. SUMMARY 5
3. PHYSICAL AND OPERATING DESCRIPTION OF EXISTING COAL-FIRED PLANTS 9
3.1 Characterization of Existing Coal-Fired Plants 9
3.2 Definition of Generic Age vs Performance Data 15
3.3 Analysis of the Performance Data 21
4. DECISION CRITERIA 25
4.1 Site Specific Criteria 26
4.1.1 Turbine-generator subsystem 28
4.1.2 Steam generator and auxiliaries 29
4.1.3 Air quality control systems 31
4.1.4 Instrumentation and control subsystem 32
4.1.5 Balance of plant subsystem 34
4.2 Program Criteria 36
4.2.1 Management priorities 36
4.2.2 Need for additional capacity 39
4.2.3 Alternatives to new capacity 39
4.2.4 Plant selection 39
4.2.5 Environmental requirements 40
4.2.6 Financial and economic considerations 42
4.2.7 Uncertainty 45
5. ECONOMIC CONSIDERATIONS 46
5.1 Summary of Selected Life Extension Projects 46
5.2 Regulatory Treatment of Life Extension Costs 52
6. CONCLUSIONS AND RECOMMENDATIONS 53
BIBLIOGRAPHY 56
APPENDIX: Plots of Coal-Fired Power Plant Historical Performance Trends 59

LIST OF FIGURES

Figure		Page
3.1	Total number of coal-fired power plants in the United States as a function of size range	13
3.2	Capacity weighted average age for all coal-fired power plants in the United States as a function of size range	13
3.3	Total installed coal-fired capacity in the United States as a function of size range	14
3.4	Annual coal-fired capacity installed in the United States as a function of online year	14
4.1	Framework for a typical life extension cost-benefit economic analysis	44
A.1	Average equivalent forced outage rate and equivalent availability factor as a function of year of operation for the 1-99 MW(e) size range	61
A.2	Average equivalent forced outage rate and equivalent availability factor as a function of year of operation for the 100-199 MW(e) size range	62
A.3	Average equivalent forced outage rate and equivalent availability factor as a function of year of operation for the 200-299 MW(e) size range	63
A.4	Average equivalent forced outage rate and equivalent availability factor as a function of year of operation for the 300-399 MW(e) size range	64
A.5	Average equivalent forced outage rate and equivalent availability factor as a function of year of operation for the 400-599 MW(e) size range	65
A.6	Average equivalent forced outage rate and equivalent availability factor as a function of year of operation for the 600-799 MW(e) size range	66
A.7	Average equivalent forced outage rate and equivalent availability factor as a function of year of operation for the > 800 MW(e) size range	67
A.8	Average equivalent forced outage rate and equivalent availability factor as a function of calendar year of operation for the 1-99 MW(e) size range	68

LIST OF FIGURES (continued)

Figure		Page
A.9	Average equivalent forced outage rate and equivalent availability factor as a function of calendar year of operation for the 100-199 MW(e) size range	69
A.10	Average equivalent forced outage rate and equivalent availability factor as a function of calendar year of operation for the 200-299 MW(e) size range	70
A.11	Average equivalent forced outage rate and equivalent availability factor as a function of calendar year of operation for the 300-399 MW(e) size range	71
A.12	Average equivalent forced outage rate and equivalent availability factor as a function of calendar year of operation for the 400-599 MW(e) size range	72
A.13	Average equivalent forced outage rate and equivalent availability factor as a function of calendar year of operation for the 600-799 MW(e) size range	73
A.14	Average equivalent forced outage rate and equivalent availability factor as a function of calendar year of operation for the > 800 MW(e) size range	74
A.15	Average forced outage rate and availability factor as a function of year of operation for the 1-99 MW(e) size range	75
A.16	Average forced outage rate and availability factor as a function of year of operation for the 100-199 MW(e) size range	76
A.17	Average forced outage rate and availability factor as a function of year of operation for the 200-299 MW(e) size range	77
A.18	Average forced outage rate and availability factor as a function of year of operation for the 300-399 MW(e) size range	78
A.19	Average forced outage rate and availability factor as a function of Year of operation for the 400-599 MW(e) size range	79
A.20	Average forced outage rate and availability factor as a function of year of operation for the 600-799 MW(e) size range	80

LIST OF FIGURES (continued)

Figure		Page
A.21	Average forced outage rate and availability factor as a function of year of operation for the > 800 MW(e) size range	81
A.22	Average forced outage rate and availability factor as a function of calendar year of operation for the 1-99 MW(e) size range	82
A.23	Average forced outage rate and availability factor as a function of calendar year of operation for the 100-199 MW(e) size range	83
A.24	Average rorced outage rate and availability factor as a function of calendar year of operation for the 200-299 MW(e) size range	84
A.25	Average forced outage rate and availability factor as a function of calendar year of operation for the 300-399 MW(e) size range	85
A.26	Average forced outage rate and availability factor as a function of calendar year of operation for the 400-599 MW(e) size range	86
A.27	Average forced outage rate and availability factor as a function of calendar year of operation for the 600-799 MW(e) size range	87
A.28	Average forced outage rate and availability factor as a function of calendar year of operation for the > 800 MW(e) size range	88

LIST OF TABLES

Table		Page
3.1	Relationship Between National Coal Model and Department of Energy Reporting Regions	10
3.2	Summary of Specific Plant Populations	12
3.3	Summary of Annual Coal-Fired Capacity Installed in the United States Since 1936	15
3.4	Summary of Selected Equivalent Coal-Fired Plant Performance Parameters as a Function of Year of Operation	17
3.5	Summary of Selected Equivalent Coal-Fired Plant Performance Parameters as a Function of Calendar Year of Operation	18
3.6	Summary of Selected Coal-Fired Plant Performance Parameters as a Function of Year of Operation	19
3.7	Summary of Selected Coal-Fired Plant Performance Parameters as a Function of Calendar Year of Operation	20
3.8	Summary of Linear Curve Fit Coefficients for Coal-Fired Plant Performance Data	22
4.1	Summary of Fossil-Fired Power Plant Equipment Wear Mechanisms	27
4.2	Summary of Components to be Included in the Turbine-Generator Subsystem Inspection Program	28
4.3	Summary of Components to be Included in the Steam Generator Subsystem Inspection Program	30
4.4	Summary of Potential Instrumentation and Control Subsystem Modernization Actions	33
4.5	Summary of Components to be Included in the Balance of Plant Subsystem Inspection Program	35
4.6	Summary of Major Systems Criteria to be Considered During the Life Extension Decision Making Process	37

LIST OF TABLES (continued)

Table		Page
4.7	Summary of Environmental Regulations to be Considered During the Life Extension Evaluation Process	41
5.1	Summary of Some Current Life Extension Programs	47

ACKNOWLEDGMENTS

This work was performed by members of the Engineering Technology Division of the Oak Ridge National Laboratory and was sponsored by the Electric Power Division of the Energy Information Administration, U.S. Department of Energy.

The authors would like to thank the Oak Ridge National Laboratory, Engineering Technology Division Word Processing Center for typing the manuscript, Judy Kibbe for editorial assistance, and the Engineering Technology Division Reports Office for preparing the figures used in this report.

COAL-FIRED ELECTRIC POWER PLANT LIFE EXTENSION: AN OVERVIEW

M. J. Taylor
L. C. Fuller

ABSTRACT

Qualitative information concerning aging and life extension of coal-fired power plants was compiled for use by the Energy Information Administration (EIA). This data is to be utilized as input to the EIA's Intermediate Future Forecasting System (IFFS) and the National Coal Model (NCM) so the life extension option can be included in their analysis and forecasting activities. Three categories of information were defined:

(a) physical descriptions that included number, age, location, and historical performance degradation data,

(b) typical economic and systems criteria that utilities should consider during the life extension decision making process, and

(c) a summary of the economic and regulatory experience of some actual life extension projects.

---

1. INTRODUCTION

Electrical utilities are having to make expansion plans without the benefit of their traditional response to capacity short-fall: new construction. Low load growth forecasts, high construction costs for both new nuclear and fossil-fueled plants, siting and environmental requirements, and increased fiscal accountability to Public Service Commissions (PSCs) have combined to make new capacity increasingly difficult to justify. As a result, the only viable option for many utilities is to defer new construction for as long as possible. While this might be the most prudent business decision, a conflict arises because the new plants are needed, or will be needed soon, to ensure adequate and reliable service. To resolve the conflict, many utilities are opting for extending the operating life of their existing, older, fossil-fueled plants. Life

extension has been shown to be a cost effective strategy and, in the near term, is likely to remain an attractive alternative for many utilities. There are several financial, regulatory, operating, and technical reasons for this assessment.

The most compelling reason is clearly financial. In the last 30 years, the cost of new generating capacity has increased by approximately 1000 percent. High capital costs and interest rates combined with long construction lead times have pushed the cost of new coal-fired capacity to $1200-$1500/kW(e) in 1985 dollars. Utilities, understandably, have come to realize that the end of capital intensive construction projects is also the start of fiscal health. As a result, many utilities are avoiding new capacity until it is absolutely necessary. Extending the life of existing fossil-fueled units, on the other hand, gives utilities an affordable means of meeting electrical demand. Nationwide, the total cost to refurbish, operate, and maintain an existing coal-fired plant for an extra 20 to 30 years is estimated to be only $100-300/kW(e).

This economic motivation to upgrade rather than add new capacity is reinforced, intentionally and unintentionally, by various regulatory agencies. It has become common practice for most state PSCs to require utilities to show that there is no other lower cost alternative before approving new construction. In addition to load management and conservation, a part of this proof is availability. Another idea gaining popularity with some PSCs is to implement incentive rate structures. This method compensates utilities as a function of how well they operate their system. One of the criteria used to measure performance is plant availability. Life extension can be a cost effective means of achieving these required system improvements.

At least one state PSC has proposed a direct incentive to encourage utilities to upgrade their existing coal-fired facilities. The Pennsylvania PSC has proposed that utilities should be allowed to collect the costs of upgrading plant output and availability through a rate surcharge rather than a rate case. This would permit a utility to immediately start collecting the costs of the upgrade. Although upgrade in this context is a less intensive effort than a life extension project,

representatives of the PSC have said there is the potential that life extension projects could also be recognized under the program.

There are operating considerations, which together with regulatory requirements and high capital investment costs, support the life extension option. These include the accuracy of stated reserve capacities and new alternate sources of power. Although many utilities now report record reserve capacities, a careful examination reveals that these reserves could become inadequate. Some of this is attributable to units scheduled to come on line in the 1980s but whose completion is now in doubt. Another reason for concern is that many utilities report reserves based on nameplate capacity rather than the more realistic dependable capacity. The main concern though stems from the composition of the current stock of generating capacity. Because new construction has essentially been halted, existing plant populations are a mix of many older, smaller units and some newer very large sized units. These smaller units continue to age and by 1990 a significant number of them will be more than 30 years old. The performance of the newer units, however, might not be sufficient to compensate for the increasing degradation of the older, smaller units. It has been established that the larger sized units, 600 MW(e) and larger, installed by most utilities during the sixties and seventies have not achieved the reliability for which they were designed. During the 10 year period starting in 1966, the effective forced outage rate of these units was twice as high as that of units 400 MW(e) or smaller. Consequently, as this mixed system continues to age, it is conceivable that shortages could develop. Utilities must then decide how to meet these shortages. Given the current regulatory climate and the capital intensive nature of new capacity, life extension may be the more tractable option.

Another system consideration that encourages life extension is the growth of alternative sources of electricity such as industrial cogeneration. As a result of the PURPA legislation, utilities are required to purchase and transport this independently generated power. The number of these facilities currently operating or in the planning stage is greater than anticipated and their popularity (within industry) continues to grow. It is not inconceivable that with continued low or

moderate load growth and large blocks of cogenerated power some utilities could eliminate the need for new plants. Any system improvements needed to compensate for aging plants could be quickly and economically provided by life extension projects.

There are some purely technical considerations that, while not directly supporting life extension, do reinforce the near term decision not to build new capacity. These deal with the replacement technology to be used for the next generation of coal-fired plants. There are still unanswered questions concerning tradeoffs between plants with low initial investment but high operating costs and plants with high capital investment costs but lower operating costs. The high investment cost category includes the traditional coal and nuclear units while the low initial investment options include combined cycle units. The Department of Energy has recently quoted a figure of $900/kW(e) for an integrated coal gasification combined cycle plant. This is considerably less than the current price of $1200-1500/kW(e) for a traditional coal-fired unit. Another unresolved technical question is just what type of fuel will be used in future coal-fired plants. Fluidized bed designs, for example, permit the use of high sulfur coal while still meeting environmental standards. There are, therefore, economic and environmental incentives for delaying new construction. Should a utility opt to wait for the new technology and a capacity shortfall develop, life extension of an existing unit could offer a quick, economical solution.

Because utilities have only just begun to seriously consider life extension, the decision making process is not that well defined. There are only limited methods for estimating the remaining life of plant components. Also, there is no single, all inclusive analysis that is capable of considering the myriad economic and operational influences that affect the upgrading decision. The purpose of this task is to compile information to permit EIA to include the effects of life extension in their forecasting activities and thus permit a better understanding of the life extension option. This objective will be achieved the through following steps.

The age of the existing stock of coal-fired generating plants will be defined for each of seven size groups and for each of the 44 NCM

regions. In addition, historical plant performance degradation data will be defined as a function of the same seven size ranges.

The various criteria that should be included in the life extension decision making process will be defined. These include economic and operating considerations for both the candidate plant as well as the utility system as a whole.

Finally, the experience of several utilities that are planning or have completed life extension projects will be summarized. Types of information compiled include, but are not limited to, cost and scheduling of life extension projects and the reaction of the various state PSCs concerning recovery of capital costs.

2. SUMMARY

Since construction of new coal-fired generating plants has essentially stopped, utilities are having to rely on existing plants for their near term future power needs. Because few new plants are entering service, the average age of those units remaining in service continues to increase and their performance deteriorate. Life extension programs are implemented to reverse the effects of the aging process and permit cost effective operation of coal-fired plants beyond their traditional lifetime. This approach to capacity expansion has several advantages over new construction: it is considerably less expensive, has fewer environmental and siting complications, and offers less financial risk.

The physical characteristics and historical performance data compiled as a part of this study clearly show the present condition and extent of performance degradation of the existing stock of coal-fired plants. Their number, average age, and installed capacity were defined for each of the 44 NCM reporting regions. Average, time dependent performance data taken from a cross section of utilities showed a continuing worsening of both availability factors and forced outage rates for all but the largest units. Performance projections using this data were not made, however one qualification was offered for the benefit of any end user. It was a reminder that simple extrapolations of historical behavior of any type should not be made when mechanisms for changes in

that behavior have been identified. This situation is applicable here in that there are indeed several such mechanisms that have the potential to alter the performance trends presented in this report. In addition to life extension, these include fewer new plants, increased levels of maintenance for all size units, and other less rigorous capital programs such as heat rate improvement.

Defining and implementing an optimum life extension program, including selecting candidate plants, was shown to require a considerable planning effort. Because it has the potential to affect the economic viability and operating reliability of an entire utility system, the planning process must consider the entire spectrum of managerial, engineering, and operating decision criteria. The first major step in the process is a complete mechanical inspection of the candidate plants. This procedure defines the remaining life of the equipment and determines those modifications necessary for extended operation. The cost of these proposed improvements together with other more traditional planning considerations are then evaluated to define the project scope. These traditional criteria include but are not limited to:

(a) the utilities long range business objectives,

(b) alternatives to new construction and life extension such as conservation, load management, and power purchases,

(c) state and federal environmental requirements, and

(d) external financing requirements, increased maintenance costs during the extended operating period, and regulatory treatment of life extension capital costs.

During the effort to define actual life extension economic experience, it was discovered that the concept and implementation, and therefore the costs, of these projects varied considerable. The majority of utilities are only just now starting their programs. Of 30 companies studied, only 9 have progressed beyond the equipment inspection step. An additional complication is that most have, or intend to, implement their programs gradually in a manner closely allied with their normal maintenance outages. This differs considerably from the common perception of life extension as an intensive replacement and modernization

effort followed by a relatively undisturbed extended operating period. A third approach encountered is one in which utilities have steadily increased operating and maintenance (O&M) and capital investment expenditures over the last few years in an effort to maintain their plants' existing performance. While this is not normally considered life extension, it does have the long term benefit of allowing units to operate past their original design life. These circumstances combine to produce an inconclusive cost experience. Overall, there is only a very limited amount of data of any kind available, and specifically that which has been reported is inconsistent. Those utilities with intensive or well defined programs are reporting total capital investment costs that range from $41/kW(e) to $100/kW(e). Those implementing gradual programs have together spent more than $173 million on capital improvements over a period of several years and expect to spend an additional $360 million in the near term. Those few utilities opting for increased annual expenditures to maintain performance levels do not specifically identify life extension costs and therefore cannot contribute at all to the cumulative experience.

Other pertinent life extension experiences defined during this study include:

(a) Predominately program capital investment costs are being reported, but these are not representative of the complete costs. For example, one utility reported a total capital investment cost of $41/kW(e), but when total O&M costs estimated for the extended operating period were added, the figure became $365/kW(e).

(b) Generally, the pending acid rain legislation is not a specific consideration in utility life extension planning activities. Any new requirements will be factored into utility economic analyses when, and if, they become law.

(c) By and large the state PSCs are allowing utilities to recover O&M and capital investment costs associated with their life extension activities. Although there is only limited experience, the consensus of opinion is that if the expenditures can be shown to be cost effective they will be allowed. Those few cases where the requests were denied or only partially allowed were extraordinary in that either insufficient

information was supplied or they were made in conjunction with other large (i.e., nuclear) requests.

Within the context of how these results affect the major goals of this study, there are three principal conclusions:

(a) The selection of candidate plants requires a complex and iterative, utility specific procedure. Life extension is not an automatic choice, and the scope (i.e., number of plants modified and length of life extension) can vary greatly among utilities.

(b) The majority of utilities that are modifying their plants are doing so gradually over time rather than all at once. Thus, the concept of life extension as a discrete event with distinctly different "before and after" plant configurations and operating characteristics is invalid.

(c) Plant life extension programs are just new being implemented on any kind of scale. Accordingly, there is insufficient data with which to define meaningful national trends.

The circumstances combine to make it difficult to develop quantitative recommendations and guidelines for plant selection criteria, typical changes in plant performance after a life extension program, and costs as a function of coal type, DOE region, plant size, and length of life extension. However, the following very speculative modeling guidelines are proposed:

(a) Those coal-fired plants 25 years and older between 100 MW(e) and 700 MW(e) in size should be selected for life extension programs.

(b) A life extension program will extend the operation of a coal-fired plant by 20 years and will cost $75/kW(e) in 1985 dollars for capital equipment improvements only. An additional cost of $10/KW(e)-year should be used when it is desired to account for increased annual O&M expenditures during the extended operating period.

(c) The post improvement performance of a plant can be determined from the historical performance data summarized in Section 3. As a first approximation, it is reasonable to expect that a life extension program will return the plant's performance to that when it was new. The curve fits that were supplied with the performance data presented as a function of year of operation can be used to calculate these post improvement performance levels.

It is recognized that these empirical guidelines have limited accuracy and are subject to change as life extension programs become more common. However, until more economic data becomes available, they are the only reasonable alternative. There is considerable activity within the utility industry that is scheduled for completion during the next year that should help to clarify matters. These projects include:

(a) scoping studies by individual utilities to define their programs,

(b) EPRI studies to define generic mechanical inspection techniques and economic analysis methodologies,

(c) a second EPRI workshop on coal-fired plant life extension, and

(d) a proposed survey by the Edison Electric Institute to define the number and extent of life extension program.

3. PHYSICAL AND OPERATING DESCRIPTION OF EXISTING COAL-FIRED PLANTS

The purpose of this portion of the report is to define data that can be used to estimate the future performance of existing coal-fired plants. Because it would be impractical to attempt to apply this data to each plant in the nation, a number of composite plant populations were also defined. The execution of and results for these two subtasks are discussed in detail below.

3.1 Characterization of Existing Coal-Fired Plants

The composite plant populations and their physical characteristics were defined by first dividing all existing coal-fired units into two categories, by geographical region and by size (nameplate capacity) within a region. Because the performance data are to be used as input to both the NCM and IFFS computer models, it was decided to geographically catalog the plants by NCM region. These 44 regions comprise subsets of the 10 Department of Energy regions, and their use will permit the estimates to be compiled directly into the more inclusive DOE regions. The relationship between the NCM and DOE regions and the 48 contiguous states is summarized in Table 3.1. Once the plant population

Table 3.1 Relationship Between National Coal Model and Department of Energy Reporting Regions

DOE Region	NCM Regions	States Included
1	1, 2	Maine, Vermont, New Hampshire, Massachusetts, Connecticut, Rhode Island
2	3, 4	New York, New Jersey
3	5, 6, 7, 8, 9, 10	Pennsylvania, Virginia, West Virginia, District of Columbia, Maryland, Delaware
4	11, 12, 13, 14, 15, 16, 17, 18, 19	North Carolina, South Carolina, Georgia, Florida, Kentucky, Tennessee, Alabama, Mississippi
5	20, 21, 22, 23, 24, 25, 26, 27	Ohio, Michigan, Illinois, Indiana, Wisconsin, Minnesota
6	28, 29, 30	Arkansas, Louisiana, Oklahoma, Texas, New Mexico
7	31, 32, 33	Kansas, Nebraska, Iowa, Missouri
8	34, 35, 36, 37, 38	North Dakota, South Dakota, Montana, Wyoming, Utah, Colorado
9	39, 40, 41, 42	Nevada, Arizona, California
10	43, 44	Idaho, Washington, Oregon

of a given region had been defined, it was further divided into one of 7 nameplate capacity ranges: 1-99 MW(e), 100-199 MW(e), 200-299 MW(e), 300-399 MW(e), 400-599 MW(e), 600-799 MW(e), and those equal to or greater than 800 MW(e).

The Generating Unit Reference File (GURF) was used as the information source to catalog the plants and define some of their physical characteristics. This was accomplished by writing and executing a series of Statistical Analysis System (SAS) computer programs which used

the GURF file as input and accomplished the following:

(a) cataloged all active coal-fired plants into one of the 44 NCM regions and then into one of the 7 size ranges,

(b) for each size range in each region, determined the total number of units, their average age, and total capacity, and

(c) for each region, defined the total generating capacity brought on line per year since 1936.

An active coal-fired plant was defined as one with an initial service date up to and including 1985 and whose primary fuel is coal. All categories of coal listed in the GURF file were defined as acceptable including bituminous, anthracite, lignite, sub-bituminous, and petroleum coke. This information for each of the 44 NCM regions is summarized in Table 3.2.

Although a region by region examination of this data could not be made, useful insight can be gained by examining it for the country as a whole. This composite data is summarized in Figures 3.1 through 3.4 and shows, respectively, the number of units, their capacity weighted average age, their total capacity, and capacity installed per year. Figures 3.1, 3.2, and 3.3 show the values of the variables at the top of each bar. The large number of bars in Figure 3.4 prevented this identification and the values are, instead, summarized in Table 3.3. Some of the more prominent trends illustrated in these figures are:

(a) the plants in the 1-99 MW(e) size range have the greatest average age, are the largest number of units, and represent the smallest fraction of total coal-fired capacity,

(b) those plants greater than 800 MW(e) in size represent the smallest fraction of total units but one of the largest blocks of generating capacity,

(c) those plants 400 MW(e) in size and larger, have the lowest average age and represent the smallest fraction of total units but also largest fraction of installed capacity, and finally

(d) the total coal-fired generating capacity installed per year since 1936 has grown significantly.

These qualitative trends agree quite well with other published summaries

Table 3.2. Summary of Specific Plant Populations

	1-99 MW(e) Size Range				100-199 MW(e) Size Range				200-299 MW(e) Size Range				300-399 MW(e) Size Range				400-599 MW(e) Size Range				600-799 MW(e) Size Range				>800 MW(e) Size Range			
	No. of Units	Average[a] Age	Total MW(e)	MW(e) (%)	No. of Units	Average[a] Age	Total MW(e)	MW(e) (%)	No. of Units	Average[a] Age	Total MW(e)	MW(e) (%)	No. of Units	Average[a] Age	Total MW(e)	MW(e) (%)	No. of Units	Average[a] Age	Total MW(e)	MW(e) (%)	No. of Units	Average[a] Age	Total MW(e)	MW(e) (%)	No. of Units	Average[a] Age	Total MW(e)	MW(e) (%)
1	3	31	30.0	6	1	25	113.6	23	0	0	0.0	0	1	17	345.6	71	0	0	0.0	0	0	0	0.0	0	0	0	0.0	0
2	0	0	0.0	0	0	0	0.0	0	2	22	482.0	43	0	0	0.0	0	0	0	0.0	0	1	16	642.6	0	0	0	0.0	0
3	20	36	1,050.8	32	6	32	716.3	22	4	27	872.0	26	0	0	0.0	0	0	0	0.0	0	1	1	692.0	21	0	0	0.0	0
4	9	32	189.5	11	2	22	299.2	17	0	0	0.0	0	2	25	652.8	36	0	0	0.0	0	1	17	659.7	37	0	0	0.0	0
5	8	32	523.0	9	6	31	931.4	17	1	23	255.0	5	3	25	1,070.9	19	1	20	405.0	7	1	16	790.4	14	2	13	1,624.5	29
6	15	38	676.1	5	15	28	2,206.3	15	1	22	299.2	2	0	0	0.0	0	4	15	2,293.3	16	4	10	2,637.0	18	7	12	6,485.3	44
7	9	39	587.8	6	2	28	305.3	3	3	27	712.5	8	0	0	0.0	0	5	17	2,814.4	30	5	10	3,420.0	36	2	14	1,632.6	17
8	0	0	0.0	0	4	34	610.0	11	2	32	439.4	8	0	0	0.0	0	1	25	495.6	9	0	0	0.0	0	4	11	4,232.6	73
9	7	35	350.0	9	8	30	1,101.7	28	6	25	1,428.8	36	1	21	359.0	9	0	0	0.0	0	1	16	694.0	18	0	0	0.0	0
10	4	30	272.7	6	5	22	941.6	20	0	0	0.0	0	3	20	1,087.0	23	1	5	442.4	9	3	10	1,937.0	41	0	0	0.0	0
11	23	36	1,353.8	8	21	28	2,935.9	17	8	22	1,915.3	11	8	12	2,731.8	16	4	12	1,985.7	12	6	11	4,197.2	24	2	11	2,160.0	13
12	8	35	307.3	2	11	27	1,499.0	12	3	21	897.6	7	1	18	359.0	3	5	14	2,473.6	19	1	13	788.8	6	7	8	6,395.8	50
13	4	29	285.6	4	3	20	527.5	12	3	21	490.2	7	2	9	703.8	10	7	14	3,292.8	49	2	2	1,478.6	22	0	0	0.0	0
14	0	0	0.0	0	0	0	0.0	0	0	0	0.0	0	0	0	0.0	0	0	0	0.0	0	1	2	650.0	100	0	0	0.0	0
15	5	30	213.5	9	1	22	100.0	4	2	20	501.3	21	1	8	305.2	12	1	4	508.3	21	0	0	0.0	0	1	16	816.3	33
16	19	35	752.0	5	23	26	3,718.5	24	5	11	1,230.6	8	2	12	711.0	5	9	6	4,618.5	30	5	10	3,415.0	22	1	15	1,150.2	7
17	4	42	240.0	7	4	31	700.0	19	9	30	1,800.0	49	0	0	0.0	0	0	0	0.0	0	0	0	0.0	0	1	18	950.0	26
18	0	0	0.0	0	10	30	1,485.2	23	0	0	0.0	0	7	24	2,245.2	35	0	0	0.0	0	0	0	0.0	0	2	12	2,600.0	41
19	10	30	362.1	3	12	32	1,777.7	13	16	20	3,821.3	28	0	0	0.0	0	7	15	3,578.8	27	4	9	2,988.6	22	1	11	952.0	7
20	18	28	770.0	18	8	30	1,008.8	23	5	24	1,170.6	27	0	0	0.0	0	0	0	0.0	0	2	14	1,360.0	32	0	0	0.0	0
21	38	33	799.0	24	8	28	1,095.8	29	0	0	0.0	0	0	0	0.0	0	2	8	888.0	24	0	0	0.0	0	1	12	841.5	23
22	24	36	387.0	5	16	30	2,288.9	14	10	29	2,284.2	14	1	18	317.5	2	3	11	1,575.6	9	11	13	6,905.4	41	2	11	2,600.0	16
23	67	28	1,929.1	16	17	30	2,385.2	19	4	25	1,087.5	9	3	23	1,095.9	9	2	17	1,080.0	9	2	3	770.0	12	4	13	1,420.0	27
24	43	32	1,359.3	7	17	31	2,561.7	14	7	19	1,707.3	9	8	23	2,890.0	16	3	13	1,527.9	8	10	14	6,336.8	35	2	12	1,786.0	10
25	40	34	1,228.2	6	22	27	2,885.0	15	11	25	2,492.6	13	4	14	1,492.1	8	13	12	6,482.8	34	5	7	3,340.0	17	1	1	1,300.0	7
26	49	33	1,668.4	23	9	25	1,124.2	16	2	25	550.0	8	6	13	2,046.8	29	2	9	1,112.0	16	1	5	617.0	9	0	0	0.0	0
27	70	34	1,355.3	22	5	28	682.4	11	1	21	238.9	4	1	12	364.5	6	2	11	1,156.4	19	2	9	1,440.0	24	1	1	800.0	13
28	0	0	0.0	0	0	0	0.0	0	1	1	240.0	2	0	0	0.0	0	13	5	6,947.0	64	2	2	1,221.6	1	3	4	2,400.0	22
29	1	6	37.4	0	0	0	0.0	0	0	0	0.0	0	3	7	1,080.0	7	17	6	8,954.2	54	9	6	6,510.6	39	0	0	0.0	0
30	3	35	10.5	0	2	22	381.6	8	1	21	253.4	6	2	11	676.1	15	3	4	1,534.0	34	0	0	0.0	0	2	16	1,636.2	36
31	19	29	901.3	10	9	21	1,090.0	12	2	11	484.5	5	1	2	320.0	4	2	10	968.2	11	6	5	4,154.8	47	1	13	893.4	10
32	75	31	1,537.5	23	5	17	705.6	1	3	14	704.9	1	1	13	349.2	5	1	10	2,830.0	8	4	5	639.9	42	0	0	0.0	0
33	38	33	944.5	8	10	24	1,572.3	13	3	15	736.8	6	2	20	662.0	5	4	17	2,032.9	17	10	10	6,278.8	51	0	0	0.0	0
34	17	33	279.8	7	1	18	172.0	4	2	17	473.0	11	0	0	0.0	0	7	6	3,361.0	78	0	0	0.0	0	0	0	0.0	0
35	1	27	50.0	3	1	17	172.8	10	0	0	0.0	0	2	10	716.8	42	0	0	0.0	0	1	2	778.0	45	0	0	0.0	0
36	8	28	135.3	2	3	24	363.2	6	2	19	437.6	7	3	11	988.6	15	9	6	4,544.0	70	0	0	0.0	0	0	0	0.0	0
37	10	39	293.5	9	2	29	227.2	7	1	1	250.0	7	0	0	0.0	0	6	5	2,632.6	77	0	0	0.0	0	0	0	0.0	0
38	15	29	415.1	8	7	23	948.3	19	3	5	762.4	15	3	13	1,050.0	21	4	4	1,841.0	37	0	0	0.0	0	0	0	0.0	0
39	0	0	0.0	0	3	15	342.0	14	2	3	524.0	21	0	0	0.0	0	0	0	0.0	0	0	0	0.0	0	2	14	1,636.2	65
40	0	0	0.0	0	3	12	503.0	10	2	6	577.8	11	0	0	0.0	0	4	5	1,646.8	32	0	0	0.0	0	3	10	2,409.6	47
41	0	0	0.0	0	0	0	0.0	0	0	0	0.0	0	0	0	0.0	0	0	0	0.0	0	0	0	0.0	0	2	4	1,600.0	100
44	5	26	53.5	3	0	0	0.0	0	0	0	0.0	0	0	0	0.0	0	1	5	560.5	29	2	13	1,329.8	68	0	0	0.0	0
All	689	32.8[b]	21,862.7		282	27.2[b]	40,479.2		127	21.0[b]	30,120.7		71	16.4[b]	24,620.8		143	9.4[b]	72,303.0		103	9.3[b]	69,543.7		54	10.7[b]	50,181.8	

[a]Numerical average age.

[b]Capacity weighted average age.

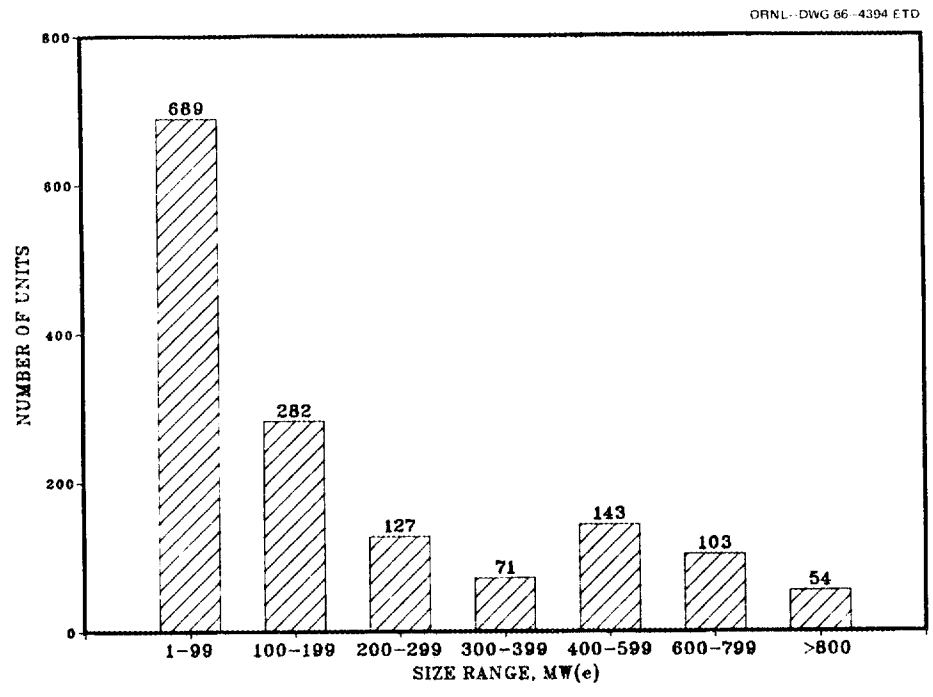

Fig. 3.1. Total number of coal-fired power plants in the United States as a function of size range.

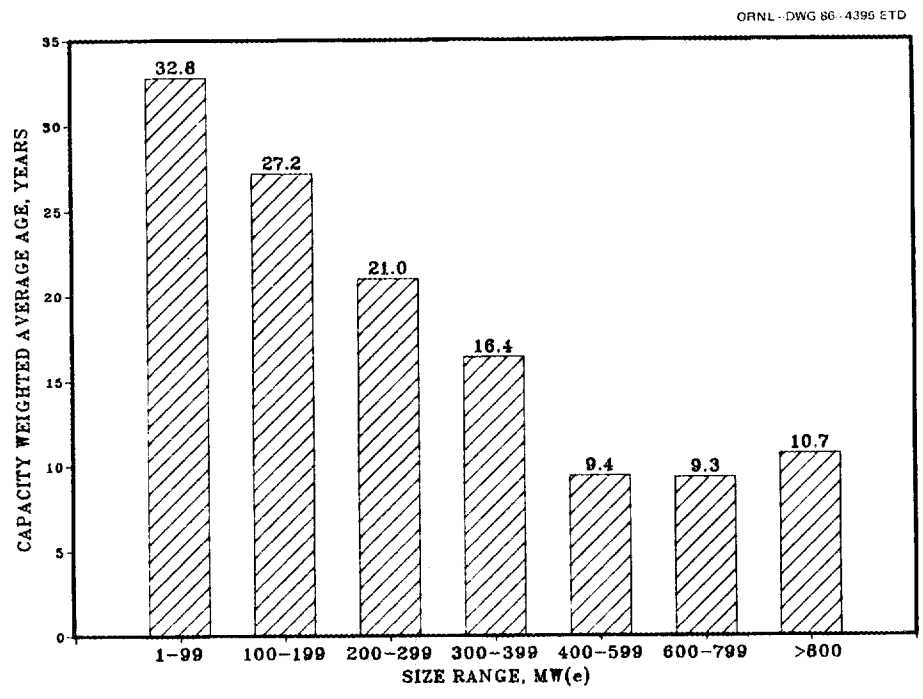

Fig. 3.2. Capacity weighted average age for all coal-fired power plants in the United States as a function of size range.

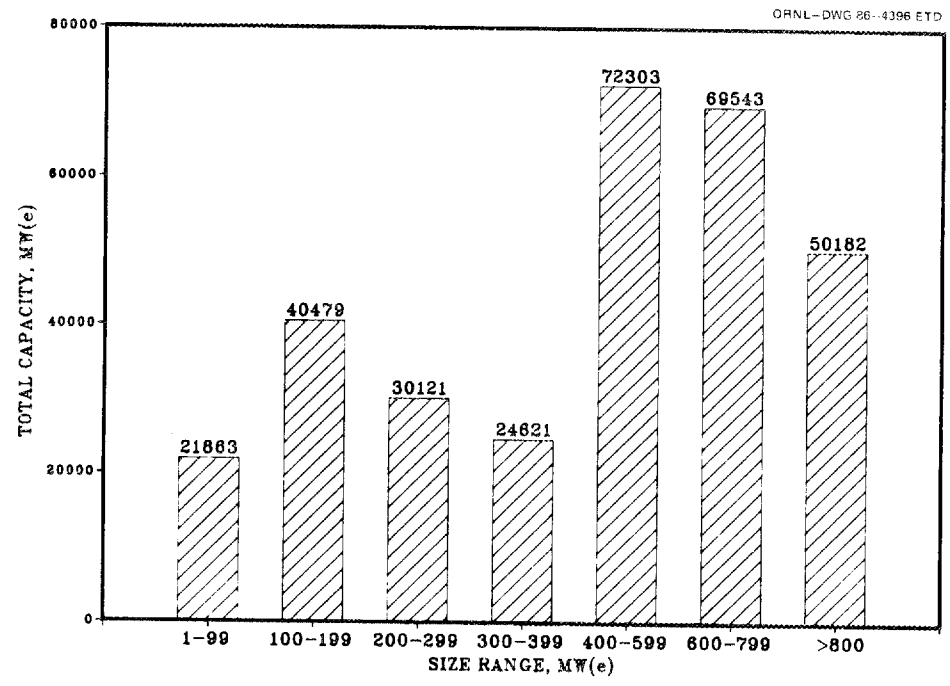

Fig. 3.3. Total installed coal-fired capacity in the United States as a function of size range.

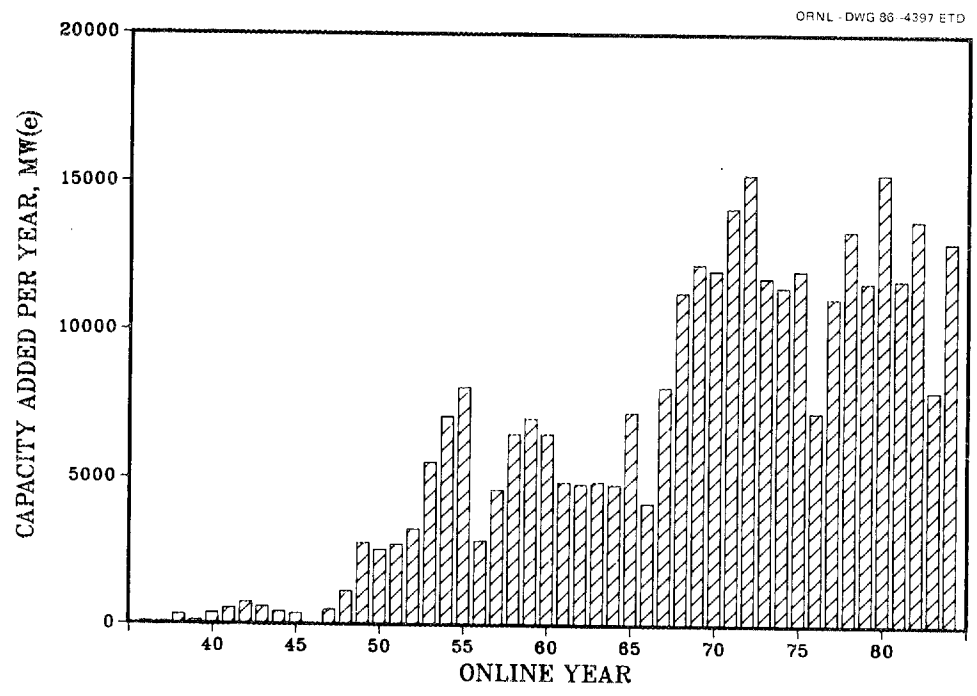

Fig. 3.4. Annual coal-fired capacity installed in the United States as a function of online year.

Table 3.3. Summary of Annual Coal-Fired Capacity Installed in the United States Since 1936

Year	MW(e) Added	Year	MW(e) Added	Year	MW(e) Added
1936	76	1952	3,240	1968	11,290
1937	64	1953	5,529	1969	12,252
1938	311	1954	7,081	1970	12,050
1939	121	1955	8,065	1971	14,143
1940	374	1956	2,854	1972	15,273
1941	533	1957	4,612	1973	11,806
1942	741	1958	6,505	1974	11,475
1943	593	1959	7,030	1975	12,049
1944	421	1960	6,505	1976	7,251
1945	356	1961	4,878	1977	11,123
1946	40	1962	4,810	1978	13,385
1947	502	1963	4,891	1979	11,647
1948	1,123	1964	4,799	1980	15,304
1949	2,768	1965	7,236	1981	11,740
1950	2,540	1966	4,160	1982	13,742
1951	2,723	1967	8,085	1983	7,980
				1984	13,011

and, accordingly, contribute to the confidence level of the regional estimates.

3.2 Definition of Generic Age vs Performance Data

To have the most consistent information with which to define plant aging characteristics, a proprietary data set was obtained from the North American Electric Reliability Council (NERC). It was compiled from their Generating Availability Data System (GADS), which contains operating data from the 160 NERC member utilities. Two separate categories of average performance data were defined for those plants whose

primary fuel was coal: one as a function of year of operation (age) and nameplate capacity and the other as a function of calendar year and nameplate capacity. The same 7 capacity ranges used to define plant populations were also used to make these performance definitions.

Average performance data similar to that which NERC publishes in its series of annual Equipment Availability Reports was defined for each size range in each category. Performance as a function of year of operation was defined by averaging the data for the "nth" year of operation from all plants of a given size range. This "nth" year of operation could occur at any point in real time. Performance as a function of calendar year of operation was defined in a similar manner. Data from each plant of a given size that was operating during a given calendar year was averaged regardless of that plant's actual age.

A great deal of information covering many aspects of plant performance was contained in the data set. Four of the most significant performance parameters were summarized for this report. These were the forced outage rate (FOR), the availability factor (AF), the equivalent forced outage rate (EFOR), and the equivalent availability factor (EAF). Equivalent performance data were included with the nominal (i.e., FOR and AF) terms because they more accurately reflect the impact of age on system performance. These terms include the effects of partial outages. Temporary deratings often occur in older plants as non-critical systems are removed from service for repair. Equivalent forced outage rate is a measure of the time a unit is derated or removed from service due to unplanned equipment failures. The equivalent availability factor is the fraction of time that a unit is in service and includes the effects of partial planned and unplanned outages.

The EFOR and EAF data as a function of size and year of operation (age) are summarized in Table 3.4 and as a function of calendar year of operation in Table 3.5. The FOR and AF terms as a function of size and year of operation are summarized in Table 3.6 and as a function of calendar year of operation in Table 3.7. All of this performance data are summarized graphically in the Appendix.

Table 3.4. Summary of Selected Equivalent Coal-Fired Plant Performance Parameters as a Function of Year of Operation

Year of Operation	1-99 MW(e) Size Range		100-199 MW(e) Size Range		200-299 MW(e) Size Range		300-399 MW(e) Size Range		400-599 MW(e) Size Range		600-799 MW(e) Size Range		>800 MW(e) Size Range	
	Equivalent Forced Outage Rate	Equivalent Availability Factor	Equivalent Forced Outage Rate	Equivalent Availability Factor	Equivalent Forced Outage Rate	Equivalent Availability Factor	Equivalent Forced Outage Rate	Equivalent Availability Factor	Equivalent Forced Outage Rate	Equivalent Availability Factor	Equivalent Forced Outage Rate	Equivalent Availability Factor	Equivalent Forced Outage Rate	Equivalent Availability Factor
1	12.05	80.28	4.24	88.04	10.31	77.86	12.53	78.12	13.91	74.19	18.13	70.70	16.04	74.09
2	1.10	91.05	2.88	91.35	7.76	81.10	9.28	81.36	14.79	74.66	16.58	73.18	18.90	72.27
3	0.34	88.04	7.81	84.22	5.42	85.59	9.97	79.72	15.68	75.96	15.98	74.22	21.36	70.13
4	0.00	89.70	3.50	90.25	4.06	88.30	11.61	79.91	16.65	73.03	17.25	74.78	19.59	71.45
5	0.04	94.75	3.41	89.88	6.56	85.83	10.10	79.40	15.11	75.07	22.09	67.63	22.29	67.50
6	0.45	95.64	3.34	88.36	7.07	84.35	10.24	78.84	15.83	70.71	18.38	70.22	22.35	67.17
7	1.28	90.30	4.17	89.40	8.50	85.07	9.90	78.81	17.93	71.04	22.57	67.96	22.96	64.21
8	4.32	89.68	3.37	88.26	7.79	85.69	13.22	77.63	17.21	70.71	21.08	68.61	24.14	66.65
9	3.11	90.23	3.43	89.24	8.20	85.74	12.56	78.40	17.04	69.29	19.15	70.19	20.31	67.14
10	4.28	90.27	5.04	87.78	10.05	82.93	15.29	74.24	19.21	68.81	18.79	71.02	28.27	60.67
11	1.97	91.74	5.65	86.13	9.17	80.68	15.16	73.67	19.49	68.44	17.19	70.72	30.09	60.66
12	3.81	86.59	7.11	84.47	9.66	80.42	16.42	72.96	19.47	67.96	18.32	67.99	23.77	64.24
13	3.07	89.45	6.31	85.49	8.23	83.94	16.10	73.01	21.53	66.35	16.72	72.82	21.00	70.49
14	2.80	88.23	6.19	86.72	8.00	84.37	17.07	71.90	23.83	66.59	23.30	63.57	20.35	60.07
15	6.24	87.75	6.70	85.82	7.45	84.36	21.30	68.61	23.89	65.34	21.01	73.72	16.53	77.14
16	3.95	89.23	7.27	84.59	9.08	82.99	21.43	64.46	31.10	60.10	26.04	68.82	10.38	76.04
17	6.31	85.72	8.42	83.68	10.97	79.46	24.41	64.66	36.11	51.82	28.46	62.10	22.85	57.09
18	5.96	86.16	8.11	83.91	9.66	81.50	26.49	62.15	32.67	61.52	21.73	62.49		
19	5.65	86.23	8.21	84.01	12.10	79.25	29.51	60.72	30.19	59.18	35.43	45.33		
20	5.26	85.90	10.71	81.25	10.43	80.84	25.72	62.53	30.72	48.65				
21	6.61	86.86	9.32	81.91	11.77	79.42	22.63	69.41	23.59	61.32				
22	7.01	85.88	10.69	80.57	11.29	80.77	22.42	64.68	34.00	53.99				
23	7.59	84.28	11.73	79.07	12.74	76.38	19.60	64.82	24.88	63.49				
24	9.68	84.40	11.40	79.99	13.16	76.37	19.73	68.78						
25	11.98	80.82	12.29	80.42	9.42	81.97	10.43	79.55						
26	9.60	83.24	11.48	79.45	8.57	82.26	5.60	79.14						
27	10.69	82.56	10.59	79.33	5.02	87.95	2.25	97.85						
28	7.15	79.99	9.37	81.71	4.60	85.29								
29	8.97	84.14	10.22	83.15	7.61	79.85								
30	11.23	81.08	12.00	82.07	11.24	61.09								
31	13.30	83.28	19.18	77.21										
32	6.18	85.64	6.99	82.74										
33	10.02	84.51	4.24	88.71										
34	12.61	83.96	7.25	92.10										
35	4.03	92.81	1.53	85.97										
36	6.28	91.80	0.71	98.02										
37	4.63	92.61	2.25	83.01										
38	3.41	93.21												
39	7.43	90.29	14.30	86.74										
40	8.01	91.21	39.55	34.78										
41	3.77	88.31	2.78	86.05										
42	3.56	86.98												
43	10.94	79.37												
44	9.20	88.39												
45	5.36	75.12												

Table 3.5. Summary of Selected Equivalent Coal-Fired Plant Performance Parameters as a Function of Calendar Year of Operation

Year of Operation	1-99 MW(e) Size Range		100-199 MW(e) Size Range		200-299 MW(e) Size Range		300-399 MW(e) Size Range		400-599 MW(e) Size Range		600-799 MW(e) Size Range		>800 MW(e) Size Range	
	Equivalent Forced Outage Rate	Equivalent Availability Factor	Equivalent Forced Outage Rate	Equivalent Availability Factor	Equivalent Forced Outage Rate	Equivalent Availability Factor	Equivalent Forced Outage Rate	Equivalent Availability Factor	Equivalent Forced Outage Rate	Equivalent Availability Factor	Equivalent Forced Outage Rate	Equivalent Availability Factor	Equivalent Forced Outage Rate	Equivalent Availability Factor
1963			11.04	72.21										
1964			5.49	86.41	5.04	86.89	8.79	84.63	8.02	79.30				
1965	2.74	91.20	2.77	90.45	3.22	88.69	7.12	81.35	12.08	75.80	22.26	75.14		
1966	1.84	93.76	3.30	90.44	3.97	88.46	6.23	84.91	6.44	81.41	18.20	75.25	8.98	88.38
1967	0.60	92.66	3.03	90.71	4.07	89.21	3.93	86.72	17.12	76.88	4.08	79.44	6.71	91.67
1968	2.19	91.33	3.38	90.63	5.53	87.66	5.98	84.10	14.95	75.63	7.65	83.19	22.88	66.86
1969	1.98	91.44	2.24	88.97	5.73	87.22	7.64	81.94	15.53	76.04	29.30	67.01	17.40	67.76
1970	3.80	90.95	4.81	88.63	6.18	86.63	11.34	78.43	15.56	73.79	27.80	64.08	35.93	54.79
1971	4.71	88.92	6.00	86.46	7.34	86.57	11.24	77.78	19.93	73.00	18.96	70.99	21.02	72.04
1972	3.94	86.84	6.81	85.95	7.73	84.31	18.49	72.05	21.31	67.14	20.36	70.02	21.18	66.30
1973	6.53	86.40	6.22	86.62	9.09	82.76	13.52	76.69	16.56	73.98	21.56	70.97	20.81	77.31
1974	7.43	85.63	8.76	83.42	11.71	82.06	17.77	71.58	23.02	68.40	23.15	69.46	27.75	64.48
1975	7.75	85.27	9.81	81.79	13.37	78.45	22.55	67.98	17.74	68.76	23.54	66.51	26.06	67.34
1976	7.16	85.30	10.56	79.85	12.77	76.67	22.60	66.41	20.33	68.22	22.99	65.65	22.55	68.97
1977	9.63	83.27	11.97	78.32	10.58	80.54	22.91	66.88	20.42	67.89	21.93	67.82	28.29	58.76
1978	10.03	85.59	11.44	80.82	13.30	77.50	19.52	69.94	21.47	68.60	25.63	65.66	24.50	66.46
1979	8.79	83.32	12.08	79.19	13.26	76.09	19.54	70.12	21.23	68.34	23.80	67.60	20.71	67.65
1980	8.30	83.04	10.73	81.06	10.96	79.72	17.96	71.50	20.14	68.01	17.47	71.05	22.34	69.48
1981	7.98	84.35	11.33	79.35	10.17	79.32	16.45	70.97	16.91	71.19	13.94	75.49	18.20	71.56
1982	9.36	83.46	10.72	79.66	8.95	81.75	15.48	73.11	13.93	73.78	12.80	74.96	18.12	70.06
1983	9.44	83.41	10.32	80.80	9.71	79.96	12.78	75.93	12.11	76.73	11.92	75.51	14.52	73.90

Table 3.6. Summary of Selected Coal-Fired Plant Performance Parameters as a Function of Year of Operation

Year of Operation	1-99 MW(e) Size Range		100-199 MW(e) Size Range		200-299 MW(e) Size Range		300-399 MW(e) Size Range		400-599 MW(e) Size Range		600-799 MW(e) Size Range		>800 MW(e) Size Range	
	Forced Outage Rate	Availability Factor	Forced Outage Rate	Availability Factor	Forced Outage Rate	Availability Factor	Forced Outage Rate	Availability Factor	Forced Outage Rate	Availability Factor	Forced Outage Rate	Availability Factor	Forced Outage Rate	Availability Factor
1	12.05	80.28	4.04	88.42	7.90	80.16	9.50	81.06	9.90	77.88	12.23	76.78	12.18	78.08
2	1.10	91.05	2.38	92.08	6.07	83.03	5.86	84.87	9.79	79.22	11.25	78.59	13.45	77.58
3	0.34	88.04	6.98	85.30	3.79	87.47	6.67	83.18	9.90	81.59	10.11	79.95	15.80	75.18
4	0.00	89.70	2.63	91.27	2.47	90.26	8.21	83.66	9.77	79.40	10.93	81.21	12.78	77.89
5	0.04	94.75	2.70	91.02	4.81	87.66	5.80	84.07	9.66	80.25	14.21	75.05	15.83	73.81
6	0.45	95.64	2.42	89.45	5.40	86.22	6.96	82.23	9.68	76.27	11.72	76.54	16.47	72.61
7	1.15	90.42	2.94	90.95	7.06	86.71	6.67	82.12	11.85	76.87	13.28	76.44	14.98	73.22
8	2.89	91.03	2.19	89.91	5.78	87.86	9.88	80.94	10.95	76.30	13.77	75.43	16.91	73.87
9	2.41	90.88	2.46	90.66	5.34	88.62	9.19	81.98	11.16	74.65	11.52	77.20	14.99	72.26
10	3.81	90.70	3.47	89.89	6.79	86.24	9.78	79.32	12.90	75.15	11.17	79.26	20.90	67.80
11	1.53	92.19	4.24	87.76	6.08	83.70	9.98	78.60	12.33	75.65	9.70	77.23	22.97	67.28
12	3.10	87.32	5.10	86.64	6.69	83.34	10.92	78.33	12.49	74.88	11.57	74.14	18.16	69.70
13	2.57	90.00	4.81	87.24	5.84	86.52	9.85	78.86	14.61	73.11	9.72	79.76	13.82	77.06
14	1.81	89.18	5.00	88.18	5.51	86.95	9.90	78.58	15.21	74.83	18.77	68.64	15.84	63.60
15	3.10	90.69	5.32	87.48	5.14	86.80	13.23	76.01	15.23	73.40	16.50	78.43	14.63	79.22
16	3.04	90.34	5.30	86.64	6.35	85.76	14.49	70.50	20.52	69.68	20.02	68.98	7.72	78.64
17	5.08	87.02	6.57	85.58	7.80	82.54	13.32	74.37	24.95	60.98	21.84	67.85	21.21	59.10
18	4.53	87.96	5.80	86.19	6.30	84.75	16.65	70.50	21.10	71.22	18.27	65.27		
19	4.60	87.44	5.34	86.77	8.52	82.55	19.91	68.96	21.85	65.72	25.49	52.12		
20	4.19	87.10	7.761	84.15	7.02	84.28	16.80	69.91	24.61	52.93				
21	4.94	88.53	6.37	84.80	8.48	82.37	14.57	76.65	18.49	65.37				
22	4.62	88.39	7.29	83.81	8.34	83.49	14.44	71.78	25.69	59.75				
23	4.74	87.24	8.24	82.24	9.80	79.08	14.39	68.96	17.77	69.47				
24	5.73	87.49	8.07	83.02	9.47	79.72	14.35	73.08						
25	19.60	82.87	8.24	84.08	6.86	84.41	7.07	82.79						
26	6.90	85.49	7.91	82.58	6.79	83.98	5.15	79.47						
27	8.17	84.25	7.70	81.85	3.39	89.48	2.05	98.03						
28	5.84	81.63	7.08	83.69	3.39	86.33								
29	6.64	85.69	6.97	85.81	5.30	81.61								
30	8.39	83.79	9.20	84.17	9.21	62.23								
31	9.57	85.79	10.48	82.59										
32	3.58	87.15	4.05	85.69										
33	8.07	85.77	2.81	89.69										
34	11.58	84.45	3.79	94.20										
35	2.49	94.08	1.15	86.53										
36	3.01	93.55	0.71	98.02										
37	0.43	97.25	2.25	83.01										
38	1.00	95.47												
39	1.92	94.12	2.30	96.16										
40	3.31	94.27	35.52	38.06										
41	2.41	88.94	1.39	88.19										
42	3.49	86.99												
43	10.83	79.39												
44	0.84	98.23												
45	0.06	79.33												

Table 3.7. Summary of Selected Coal-Fired Plant Performance Parameters as a Function of Calendar Year of Operation

Year of Operation	1-99 MW(e) Size Range		100-199 MW(e) Size Range		200-299 MW(e) Size Range		300-399 MW(e) Size Range		400-599 MW(e) Size Range		600-799 MW(e) Size Range		>800 MW(e) Size Range	
	Forced Outage Rate	Availability Factor	Forced Outage Rate	Availability Factor	Forced Outage Rate	Availability Factor	Forced Outage Rate	Availability Factor	Forced Outage Rate	Availability Factor	Forced Outage Rate	Availability Factor	Forced Outage Rate	Availability Factor
1963			7.60	75.06										
1964			3.47	88.47	3.69	88.42	7.90	86.11	3.47	83.27				
1965	2.65	91.29	2.11	91.32	2.81	89.43	5.83	82.68	10.59	77.41	21.68	75.75		
1966	1.77	93.88	2.52	91.51	2.74	90.04	5.57	85.65	5.50	82.48	16.69	76.64	8.47	88.87
1967	0.59	92.68	2.24	91.89	2.50	90.91	2.95	87.75	13.88	80.33	3.52	79.91	6.07	93.20
1968	1.91	91.72	2.80	91.62	4.52	88.78	4.75	85.78	10.46	80.20	5.33	85.18	15.74	74.27
1969	1.81	91.71	3.78	89.71	4.15	88.95	6.15	83.56	11.36	79.99	28.09	68.07	14.29	75.41
1970	3.55	91.34	4.11	89.64	4.78	88.32	8.99	80.89	10.76	78.45	17.57	74.28	30.62	60.54
1971	4.24	89.98	4.16	88.45	5.72	88.29	7.79	81.11	15.95	76.98	13.11	76.76	17.45	76.54
1972	2.50	88.85	5.01	87.90	5.79	86.92	10.10	80.06	16.30	72.04	14.48	75.48	15.34	74.58
1973	3.38	89.37	4.91	88.18	6.67	85.11	9.00	81.26	11.23	78.96	16.42	76.03	14.90	82.44
1974	3.93	88.73	6.19	85.97	7.70	85.83	11.50	77.49	16.92	74.12	15.55	76.76	20.18	70.75
1975	5.18	87.32	7.36	84.14	9.81	81.88	15.07	74.83	12.37	73.73	13.73	75.56	18.64	73.85
1976	5.86	86.55	7.32	82.98	8.95	80.18	13.88	74.28	12.82	74.87	14.37	74.26	16.34	74.35
1977	6.22	86.36	8.75	81.37	7.30	83.65	15.14	74.42	12.64	75.18	15.62	74.10	19.64	66.53
1978	7.84	87.41	6.82	85.04	8.66	81.82	11.67	76.87	12.41	76.73	15.91	74.85	18.06	72.65
1979	5.96	86.43	8.16	82.91	9.40	79.79	11.78	77.35	12.56	76.28	14.50	76.26	14.89	73.22
1980	4.80	85.95	7.39	84.24	7.51	82.95	10.95	78.08	11.93	75.70	9.78	78.00	16.35	75.01
1981	5.63	86.20	7.87	82.49	7.04	82.41	11.19	76.19	9.69	77.61	8.87	80.43	12.68	76.84
1982	7.33	85.09	7.89	82.13	5.93	84.62	10.04	78.03	9.15	78.34	7.66	80.53	12.17	76.13
1983	7.29	84.86	6.95	83.47	7.12	82.33	8.96	79.64	8.15	80.69	7.56	79.82	10.53	77.72

3.3 Analysis of the Performance Data

The mathematical analyses of the performance data are summarized in Table 3.8 and consist of least squares, linear curve fits. This type of curve fit has the form:

$$Y = a + bX$$

The Y term represents the variable of interest and X is the time coordinate, either the age in years or the actual calendar year. The a and b coefficients of the fits for all the performance data are summarized in tabular form in Table 3.8 and are shown graphically in Figures A.1 through A.28.

Before actually discussing the data, the rationale for defining aging characteristics as a function of two separate time frames will be explained. Performance trends specified as a function of year of operation (actual age) are really meant to be applied to specific units. As an individual plant ages it is not unreasonable to expect that its degradation will follow some average trend. However for the time dependent behavior of a composite group of plants actual age trends can be inadequate. This is due to the fact that the composite group is a dynamic system; some units come on line, some are retired, and all have different levels of maintenance and reliability. If one is willing to stipulate that the "capacity weighted average age" of the composite group simulates the aging process of an individual plant then year of operation data would be adequate. If this is not an acceptable assumption, then an alternate set of criteria must be used. Degradation defined as a function of calendar year of operation meets this need. Trends developed in this way implicitly include the effects of system operation such as maintenance level and plant retirements. Accordingly, this type of data will more accurately model the behavior of a composite group. No attempt will be made here to suggest which category is more appropriate for a specific analysis; that decision is one the end user must make.

Table 3.8. Summary of Linear Curve Fit Coefficients for Coal-Fired Plant Performance Data

Size Range, MW(e)	Equivalent Forced Outage Rate				Equivalent Availability Factor			
	Year of Operation		Calendar Year of Operation		Year of Operation		Calendar Year of Operation	
	a	b	a	b	a	b	a	b
1-99	2.913	0.1353	-998.9	0.5091	89.30	-0.0972	1277.0	-0.6028
100-199	3.714	0.2128	-793.5	0.4061	89.44	-0.2694	925.1	-0.4264
200-299	7.587	0.8232	-880.7	0.4506	85.45	-0.2406	1325.0	-0.6292
300-399	12.30	0.2613	-1416.0	0.7248	77.54	-0.2866	1751.0	-0.8490
400-599	11.93	0.8710	-665.5	0.3457	77.56	-0.9629	910.8	-0.4247
600-799	15.25	0.5592	117.5	-0.4974	75.74	-0.7643	462.4	-0.1981
>800	21.53	0.3150	-356.6	0.1912	70.44	-0.3293	1035.0	-0.4886

	Forced Outage Rate				Availability Factor			
	Year of Operation		Calendar Year of Operation		Year of Operation		Calendar Year of Operation	
	a	b	a	b	a	b	a	b
1-99	3.05	0.0471	-657.9	0.3355	89.30	-0.0256	1016.0	-0.4698
100-199	3.09	0.1278	-522.7	0.2677	90.57	-0.2174	714.3	-0.3184
200-299	5.40	0.0641	-571.1	0.2925	87.93	-0.2446	1073.0	-0.5008
300-399	8.05	0.1807	-729.4	0.3744	81.98	-0.2503	1149.0	-0.5419
400-599	6.72	0.7098	-175.4	0.0947	82.92	-0.8793	481.5	-0.2046
600-799	8.46	0.5737	724.14	-0.3599	82.80	-0.8470	-133.3	0.1064
>800	14.54	0.1407	23.06	-0.0037	77.29	-0.5032	872.7	-0.4036

The equivalent and nominal performance data defined as a function of plant size clearly show the effects of aging on power plant performance. Although there is considerable scatter in some of the individual data points, the time averaged trends indicated by the linear curve fits have the expected behavior. For both data types (i.e., equivalent and nominal) and time frames, the forced outage rate increases with increasing time and the availability factor decreases. There are several reasons for the variance in the individual points, and because they can influence performance projections, it is appropriate to briefly discuss them.

Within a given size range there are several reasons for the observed scatter including:

(a) each point represents an average value from a number of plants and the number of plants varies between points,

(b) the data is a composite from several different utility systems,

(c) the design of the power plants represented by the data changes as a function of time, and

(d) certain size ranges of plants have received increased maintenance levels in recent years.

One reason the number of plants varies between points is that NERC collects performance data from a number of utility systems. Not all systems have the same plant composition, and within a system units are continuously brought on stream and/or retired. These dynamic populations especially affect data defined as a function of calendar year of operation. Data scatter in both time frames can occur because of improved plant designs. A data point defined as a function of age (i.e., first year of operation) can include a plant designed in the 1950s as well as one designed in the 1970s. Data defined for a given calendar year includes all plants designed and built up to that particular year. Another reason for data scatter, especially recent reversals in historical trends, is that some utilities have increased maintenance on some plants. The data in Figure A.4 illustrates this quite well. It summarizes performance as a function of age for the 300-399 MW(e) size range and shows a steady worsening in both the equivalent availability

factor and forced outage rate. This decrease continues until year 20 at which time the performance underwent a dramatic improvement.

When using these data to make estimates of future performance, the end user should proceed cautiously. This admonishment is not due to any deficiency in the data but rather to the uncertainty inherent in any kind of future prediction based on historical trends. A common assumption made when using historical data is that the performance will continue along historical lines. This assumption has been shown to be wrong in the utility industry in general (e.g., load growth projections made in the 1970s) and is just as wrong for this current situation. There are several mechanisms active today that have the potential to alter traditional performance characteristics. These include but are not limited to:

(a) increased maintenance on some units,

(b) the intensive modernization, upgrading, and life extension projects now being implemented, and

(c) the increasing average age of coal-fired power plants.

Perhaps the most obvious event that will affect future performance is the increasing age of coal-fired plants. These mechanical systems have distinctive aging patterns that can suddenly alter their performance for the worse. This should be a concern when extrapolations beyond the range of available data are made. Performance trends will also depart from traditional patterns when maintenance schedules are changed and/or major equipment modifications are made. This last mechanism is especially important given the current interest in plant life extension.

Any of the renovation efforts currently under consideration by the utility industry could alter historical performance trends, and life extension projects in particular have the largest potential to cause change. These extensive replacement and modernization efforts, quite literally, reverse the aging process. When a significant number of plants have been subjected to life extension programs, historical performance data is no longer applicable and should not be used.

4. DECISION CRITERIA

The purpose of this section of the report is to define various life extension decision criteria so the plant selection process can be incorporated into existing EIA computer models. To accomplish this, it will first be necessary to briefly summarize the various criteria and evaluation procedures that are currently utilized by the utility industry. This information represents the current thinking within the utility industry; however, the life extension evaluation process is still in its infancy and continues to be actively investigated and refined. The Electric Power Research Institute (EPRI), for example, currently has several projects underway to define both plant specific mechanical inspection procedures and system wide economic evaluation analyses. As these studies are completed, evaluation processes in general and pertinent criteria in particular will become better defined.

Two categories of criteria will be discussed: site specific or project considerations and system wide or program factors. Although these criteria will be presented in two separate groups, it should be understood they are indeed related and that an iterative procedure is required for an accurate evaluation. The reasons for this are obvious: one looks at only a specific facet of the program while the other evaluates the program from a corporate perspective. The site specific, engineering oriented analysis should identify and cost the steps necessary to implement a project at a candidate plant. The systems analysis then utilizes this cost data as it compares the life extension project with other corporate investment alternatives. EPRI recommends that the iterations start with a conceptual systems analysis. The reasons for this are:

(a) it evaluates the life extension alternative against other business alternatives and thus establishes limits of initial involvement, and

(b) it can identify prospective candidate plants.

If this preliminary analysis finds life extension to be potentially cost effective, then detailed equipment inspections should be conducted on

the prospective plants. These inspections define the cost of implementing the life extension project. The cost is then used to determine if life extension is still a feasible corporate goal. This iterative sequence is repeated until a final decision can be made.

The following discussion of decision criteria utilizes nomenclature that is in common use within the electrical industry, and it is assumed that the reader is familiar with these terms. For an introduction to coal-fired electric power plants, a review of entry 33 in the Bibliography prior to proceeding is recommended. For additional detail, entry 34 is recommended.

4.1 Site Specific Criteria

Even though a utility will make the final life extension decision using a sophisticated systems analysis, the very first step in the process must be to define the present condition of the candidate plants. Quantifying the effects of aging and estimating the remaining life of plant components are considered by the utility industry to be the most critical operations in the life extension process. They affect the cost of the life extension program, equipment replacement schedules, operating and maintenance procedures of the modified plant, and ultimately the reliability of the entire generating system.

The term "aging" refers to the accumulated wear of plant equipment due to operational and environmental conditions. It can occur as the result of one or more of four basic mechanisms: creep, fatigue, erosion, and corrosion. A brief summary of the causes of this wear and the equipment it typically affects is given in Table 4.1. The effects of these processes are cumulative, that is they worsen as the equipment ages. Even though original equipment designs include allowances for wear, these safety factors are intended for a specific, finite time period. Any decision to operate the equipment beyond this design lifetime requires a careful assessment of the means of overcoming the aging process. A thorough mechanical inspection is the only dependable means of establishing the remaining life of plant equipment and its current rate of degradation. In addition to high profile items such as boiler

Table 4.1 Summary of Fossil-Fired Power Plant Equipment Wear Mechanisms

Wear Mechanism	Components Affected	Causes
Creep	Superheat and reheat tubes, outlet headers, turbine forgings and shells, main steam lines, valves, and bolting	High pressure and temperature steam
Fatigue	Turbine blades and shafts, boiler headers, drums and tubes, pump and fan components, and generator winding supports	Thermally induced stress and periodic steam and electrical forces
Erosion	Turbine blades and nozzles, boiler tubes, fan blades, and pumps	Hard particle impingement and fluid cavitation
Corrosion	Boiler tubes, turbine blades and discs, precipitators, scrubbers, stacks, and air preheaters	Water and steam impurities, coal ash constituents, and acid deposition

Source: Armor, A. F., and Scheibel, J. R., "Plant Life Extension: Determining the Correct Strategy," presented at EPRI Life Extension Conference, Washington, D.C., June 12—15, 1984.

tubes and turbine rotors, consideration must also be given to turbine foundations, stacks, cooling towers, boiler drums, coal conveyor systems, etc. This intensive examination and replacement is what differentiates a life extension program from other less rigorous efforts such as availability upgrades and heat rate improvements.

Because the results of equipment inspections are so critical to the success of a project it is appropriate to discuss in some detail the rationale and makeup of a typical inspection program. The most expeditious way of accomplishing this is to define specific plant subsystems, identify the more prominent components within these groups, and then elaborate on some of their inspection considerations. Only brief discussions are given here, and the reader is encouraged to examine entries 4, 27, 28, 30, 31, and 32, of the Bibliography for excellent discussions of mechanical inspection criteria. It is sufficient here to define and and discuss five plant subsystems: turbine generator, steam generator, air quality control, instruments and control, and balance of plant.

4.1.1 Turbine-generator subsystem

Those prominent turbine and electrical generator components that are normally included in an inspection program are summarized in Table 4.2. The reasons for including these components and some explanation of the potential benefits that life extension can have are discussed below:

(a) During the life of a turbine, the rotor is the one component subjected to the most stress. It results primarily from thermal transients generated during startup, shutdown, and cyclic operations. The conduct of an inspection program depends a great deal on turbine age. Turbines with less than 20 years of service should be approached with a view towards restoration rather than modernization. This includes items such as replacement of worn or damaged turbine blades and control valve components. Turbines with more than 20 years of service (those designed before about 1960) must also consider wear of highly stressed items such as high temperature rotors and casings. These older designs can often benefit from recent improvements in bucket design and materials of construction.

(b) Turbine shells, like rotors, can also be subjected to severe operating conditions and should be considered for wholesale replacement. This is especially true of the older shells which were designed

Table 4.2 Summary of Components to be Included in the Turbine-Generator Subsystem Inspection Program

Turbine
Rotor, including buckets
Shell
Nozzle
Control system and valving
Seals
Generator
Stator
Field and excitation systems
Field forging
Collectors and brush holders

to operate primarily as pressure vessels. The main advantage of a new shell is that it benefits from improvements in materials and casting techniques. A secondary benefit is that new design features can be incorporated into the shell to account for cyclic duty or capacity uprating.

(c) Steam valves should be inspected from the perspective of replacement with a newer design. Improvement in design and materials can reduce the number of working parts and reduce wear mechanisms such as erosion and corrosion.

(d) Shaft ends on older turbines were sealed using water seals. Retrofitting these to steam seals offers many advantages especially if cyclic operation is anticipated. These advantages include smoother operation, less operator attention, reduced maintenance, and elimination of water erosion.

(e) Older hydrogen cooled generator stator windings were insulated with an asphalt-mica insulation that is prone to tape migration and girth cracks. It can be cost effective to replace this insulation system with one that utilizes newer materials and eliminates these problems. An additional benefit is that during the actual rewind procedure the end winding support and slot support systems can be improved to make the winding more resistant to fault forces.

(f) It can also be advantageous to consider rewinding the generator fields. New field designs have the potential to eliminate prewarming and reduce routine maintenance inspections. These new designs include direct radial cooling of the conductors, which increases capability and reduces electrical losses. These also include procedures for winding the conductor that reduce breaking and increase reliability during cyclic operation. Collector rings and brush holders wear during normal service and should be replaced routinely. New brush holder designs are available as a retrofit which permit brushes to be changed out without removing the generator from service.

4.1.2 Steam generator and auxiliaries

The life extension process for steam generators consists primarily of repair or replacement of worn, damaged, and outdated components, and

the inspection sequence should be structured accordingly. A summary of those components that should be inspected is contained in Table 4.3. Some aspects to consider during the inspection include:

(a) All boiler pressure parts and components, except the drums, may be considered as replaceable or repairable. Highly stressed parts of the superheater and reheater tubing can be removed and replaced with materials that can withstand more severe operating conditions. Eroded convection surfaces can be redesigned for greater spacing between

Table 4.3 Summary of Components to be Included in the Steam Generator Subsystem Inspection Program

Boiler Pressure Parts
Furnace, roof, and floor
Economizer, superheater, and reheater
Drums and headers, including hangers and expansion joints
Boiler Structure
Main hanger rods
Buckstays
Suspension level steel
Boiler Setting
Casing, lagging, refractory, and insulation
Furnace hopper and lower seal
Dead air spaces
Penthouse
Air and Flue Gas Systems
Air preheater
Fans
Air and gas ducts
Fuel System
Windbox
Burners
Coal handling systems

Source: Davis, K., Hunter, J. S., and King, J. P., "Boiler Life Extension — A New Lease on Life," Proceedings of the American Power Conference, Chicago, Illinois, Volume 47, 1985.

tubes. Extended surface economizers can be replaced with smooth tube designs to reduce plugging.

(b) Parts of the coal conveying system can be replaced with wear resistant ceramics. These materials can be applied to nearly all components of the conveying system including pulverizers, elbows, and shut off valves. Design modifications using these materials can result in reduced maintenance costs and forced outage rates.

(c) Fuel burners can be replaced with newer designs that reduce the amount of nitrogen oxides emitted and also improve heat transfer conditions in the lower furnace.

4.1.3 Air quality control systems

A plant's air quality control system has the potential to be the single most important factor in the life extension decision. More than any other component, its treatment depends heavily on how other subsystems are modified. In addition, utilities cannot unilaterally upgrade these systems. The appropriate state and federal regulatory agencies must inspect and approve any design changes. This constraint affects both the conduct of the inspection and the eventual implementation and will be elaborated on later. From a component inspection perspective there are two basic systems to consider: electrostatic precipitators and flue gas desulfurization (scrubber) systems.

Because most precipitators have the same basic mechanical design, their inspection program can focus on specific components. These include, but are not limited to, casing and hoppers, collection plates, discharge electrodes, the electrical system, and the rapping system. Inspection considerations include:

(a) Casings and hoppers are subject to corrosion and should be inspected with regard to structural integrity.

(b) Collection plates are a component most subject to deterioration. This occurs as a result of their geometry (thin sheets) and the high gas velocities to which they are exposed. These should be inspected from the standpoint of complete replacement.

(c) Discharge electrodes are most affected by corrosion and should be considered for replacement. In addition, any modifications that can

be taken to prolong electrode life should be identified during the inspection. These include design changes to reduce the causes of corrosion, hopper level detectors, and changes in the electrode material of construction.

(d) The voltage control system is a prime candidate for modernization. Recent improvements in materials and microprocessor technology can improve collection efficiency and reliability, reduce corrosion and erosion, and reduce electrode failure rates.

(e) Rappers or vibrators are subject to mechanical wear in their electro-mechanical components, and these should be replaced. If the inspection shows deterioration of the rapper itself, outright replacement should be considered. There are several alternative designs available, and a choice should be made in concert with other precipitator modifications.

The process of determining a life extension procedure for scrubber systems is somewhat more complicated. There are several different designs currently in operation and, unfortunately, most were installed concurrent with their technical development. Any inspection program must be conducted with an eye toward extensive modification to reduce operating costs and improve operating reliability and efficiency. These modifications include installation of spare scrubber module, possibly changing the chemical reagent from lime to limestone, and using a landfill type disposal instead of ponds.

4.1.4 Instrumentation and control subsystem

The evaluation of existing instrumentation and control (I&C) systems differs somewhat from other plant systems in that besides modernizing components, the entire control philosophy is often updated. Whereas instrumentation in the past was confined to mainly sensors, indicators, and recorders, new technology permits a broader perspective. State of the art equipment such as programmable controllers, microcomputers, and high speed data acquisition systems are being applied to virtually all aspects of plant operation. Table 4.4 summarizes typical I&C modernization objectives and some specific applications.

Table 4.4 Summary of Potential Instrumentation and Control Subsystem Modernization Actions

Objective for Instrumentation and Control Improvement	Specific Action
Cyclic Operation	Boiler and turbine controls modified to improve response time to meet variable load demand requirements
	Automatic turbine runup aids reduce startup hazards
Performance Improvement	Computer control of those parameters that affect boiler efficiency and turbine cycle heat rate
Safety and Reliability	Burner control and fuel safety system for automatic operation
	Furnace implosion prevention system
	Turbine supervisory instrumentation to detect mechanical changes in time to permit preventative maintenance
	Rotor stress monitor to calculate and accumulate cyclic life expended
Reduction in Operating and Maintenance Costs	Central control stations reduce number of operators required
	Data acquisition systems can detect equipment degradations in a timely manner

As one might expect, this expanded scope increases the complexity of the inspection program. In addition to defining existing equipment deficiencies there is now an additional requirement to closely coordinate the planning activities of non-I&C personnel. Some of these planning considerations include:

(a) It is more efficient to perform the I&C modifications at the same time the applicable systems (i.e., boiler and turbine) are improved.

(b) It takes considerable time and impartial analysis on the part of the utility to evaluate and select the most appropriate and cost effective I&C equipment.

(c) Replacement of pneumatic controls with electrical designs can be cost effective for major plant components.

(d) Considerable improvement in human factor aspects can be achieved at the same time control panel and control room improvements are made.

4.1.5 Balance of plant subsystem

Balance of plant components are included in an inspection program to insure they will operate reliably during the plant's extended service life. Table 4.5 summarizes the equipment normally included in this subsystem. Some important inspection and planning considerations include:

(a) The primary concern for the steam condenser is the condition of the tubes and the need for a retubing. The inspection should determine the extent of tube side fouling and tube wall degradation. If a cooling water treatment (corrosion prevention) system is not in place, one should be considered.

(b) The integrity of the cooling tower fill and structural supports should be established.

(c) Boiler feedwater pumps and associated piping should be inspected to insure proper operation (e.g., correct net positive suction head). In some cases replacement of the existing pump with one of a newer design and materials of construction can be economical due to increased reliability.

(d) All other heat exchangers should be inspected for the existence of cracks and fouling. As a group, heat exchangers experience increased tube failure rates with time. The inspection should provide sufficient data for a utility to determine remaining life and if a retubing is necessary.

(e) The fire protection system should be inspected for plugged lines and valves.

Table 4.5 Summary of Components to be Included in the Balance of Plant Subsystem Inspection Program

Condensing System
Steam condenser
Air ejectors and vacuum pumps
Condenser Circulating Water System
Pumps, motors, and valves
Cooling towers
Traveling screens
Water treatment program
Condensate System
Hotwell, pumps, and motors
Booster pumps
Piping and valves
Low pressure heaters and deaerators
Polishers and chemical addition
Feedwater System
Pumps and drive motors
Piping and valves
Heater Drain System
Drain pumps
Piping and valves
Extraction Steam Piping and Valves
Electrical Systems
Switchyard
Main transformer
Auxiliary transformer
Startup transformer
Smaller transformers, breakers, conductors, and motor controls
DC electrical system
Auxiliary Systems
Service water
Closed cooling water
Auxiliary boiler
Service air
Instrument air
Fire protection
Building structures

Source: Proceedings of EPRI Life Extension Conference, Washington, D.C., June 12–15, 1985.

4.2. Program Criteria

Even though the systems analysis portion of a life extension study can vary considerably among utilities, most have similar execution sequences and require the same general types of input. The specific value of the variables (e.g., cost of money) may vary among utilities and regions, but virtually all economic oriented analyses utilize similar input. The purpose of this section of the report is to define some of these planning variables. To accomplish this seven major categories of decision criteria will be defined and discussed. These groups and some of their associated considerations are summarized in Table 4.6. As was done for the site specific criteria, only a brief overview will be presented here. Entries 3, 11, 13, 14, 17, 18, 24, and 30 of the Bibliography contain excellent, detailed analyses of this subject.

The reader should assimilate the information presented below as individual decision criteria and not as sequential pieces of an evaluation procedure. Even though much of it is related and iterations are often necessary to properly define it, separate discussions are utilized here for the sake of simplicity and effective communication.

4.2.1 Management priorities

The decision to implement a life extension program must be primarily an upper level management decision. It should be treated as one of several strategic investment choices, in the sense that it has the potential to affect the utility's competitive position and operational future. To make an effective decision, corporate planners must consider a variety of influences ranging from their own long range business objectives to the ratepayers' perceptions of managerial prudence.

These multiple objectives are very often conflicting. For example, should a utility plan to remain only an electrical producer or diversify into a full service energy company? Another difficult tradeoff is the traditional dual responsibility to provide reliable, low cost service to the ratepayer and to also achieve acceptable financial performance for the investor.

Table 4.6 Summary of Major Systems Criteria to be Considered During the Life Extension Decision Making Process

Management Priorities
- Long range business objectives
- Increased accountability to PSCs

Need for Additional Capacity
- Load forecast
- Reliable reserve margin

Alternatives to New Construction
- Conservation
- Load management
- Purchase replacement power
- Life extension
- Upgrade

Plant Selection
- Equipment inspections
- Operating history
- Proposed duty

Environmental Requirements
- Existing federal and state regulations
- Pending acid rain legislation

Financial and Economic Considerations
- Required rate relief or construction work in progress support
- External financing requirements
- Effect of new capacity on required rate of return
  - displaced power cost
  - time during the year
  - system load, capacity mix, and fuel cost
- Cost of plant refurbishment
  - size, number and type of unit
  - extent of refurbishment
  - length of refurbishment period
  - replacement power cost during refurbishment
- Timing of life extension project
- Improvement in equivalent availability
- Direct and Indirect cost
  - increased maintenance costs
  - total costs capitalized or expensed

Uncertainties in technical and economic variables

Choosing an applicable course of action requires a careful assessment of a myriad of decision criteria including opportunities for pricing and marketing initiatives, profitable diversification, and regulatory constraints. The following three examples, taken from entry 17 of the Bibliography, illustrate the range of possibilities:

(a) Company A has excess nuclear and coal capacity, but its neighboring utilities rely heavily on expensive oil. Recognizing the opportunity for profitable off system sales, it institutes availability and heat rate improvement programs.

(b) Company B also has excess coal capacity and already sells much of its output to neighboring utilities. This company wants to postpone new generating plants and accordingly opts for life extension of its existing power plants.

(c) Much of company C's generating stock consists of aging oil-fired units and combustion turbines. In addition, almost half of its load is supplied by purchases from neighboring utilities. The company projects low or zero load growth and is cash constrained due to large construction programs. Accordingly, it decides to maintain only a few of its units and let the older fossil units deteriorate.

These scenarios demonstrate different but equally valid corporate objectives. Company A's focus on short term profit from wholesale sales dictated cost reducing performance improvement programs. Company B's concern with its long term financial condition supported a life extension program. Company C decided that major investments in most of its plants were not justifiable and acted accordingly.

Public acceptance of business decisions, or more correctly increased accountability to the PSCs, has become an important managerial consideration. Utilities have been and continue to be criticized for undertaking large capital intensive construction projects that were difficult to control, experienced large cost overruns, and if completed resulted in substantial rate shock. Although there are legitimate reasons for some of these events, they have nevertheless fostered an image of less than capable utility managers. Implementing life extension programs has the potential to reverse this perception. Life extension of coal-fired plants may be favorably received because it appeals to the

public's desire for efficiency. Because these projects are inherently smaller and less capital intensive they offer increased flexibility in responding to changing load growth or financial conditions. Thus, it can give the impression that the utility management is once again in control of events.

4.2.2 Need for additional capacity

Need for additional reliable capacity must be recognized before a life extension project can be considered. The need for some type of additional capacity results from a combination of two basic mechanisms: load growth outstripping system capacity and decreasing performance of existing plants as they age. Load growth projections are a science in their own right, and it is not necessary to summarize the means or data required here.

4.2.3 Alternatives to new capacity

In addition to new capacity, which currently is not an attractive option, there are several alternatives available to a utility which is trying to deal with aging capacity. They fall into one or more of three basic categories: reduce consumption, purchase replacement power, or undertake some type of plant improvement program. To reduce consumption, a utility can implement ratepayer conservation projects and/or load management programs. Buying any needed replacement power is becoming a more attractive alternative to some utilities because of industrial cogeneration and increased amounts of wheeling. Strict environmental and siting requirements make new capacity undesirable and thus encourage modernization of existing plants. These modernization efforts vary in scope from upgrading individual pieces of equipment to an extensive life extension program. Making an optimum choice between these alternatives however requires evaluating virtually every facet of a utility's situation. The three example utilities discussed in the previous section illustrate the level of decision making necessary.

4.2.4 Plant selection

The selection of the particular plant, or plants, to include in a life extension program is in itself quite an involved task. The choice

is a function of the plant's current condition, its post improvement operating mode, and the cost of the modifications necessary to permit the proposed level of service. The fuel type and size of the candidate plant also influence the selection, but will be covered in the discussion of economic and financial considerations.

Defining the remaining life of a candidate plant is one of the most critical operations in the life extension process. Its present condition determines the number and extent of equipment modifications. A review of the plant's operating history combined with a mechanical examination of components are the only reliable means of determining this. Details of these inspection procedures were discussed in Section 4.2. The proposed service and length of life extension also affect plant selection. A plant scheduled for cyclic service, but which historically has been base loaded, will require extensive boiler and turbine modernization to operate effectively. The length of the extended operating period determines the financial break even point (i.e., benefit-cost) and therefore influences the number of modifications that can be cost effective.

4.2.5 Environmental requirements

At the present time there are approximately 50 federal and state laws that should be considered during the life extension decision making process. Quite understandably, meeting these requirements can significantly affect the economic viability of a life extension program. A brief summary of these existing requirements is given in Table 4.7. This table, and most of the following narrative, were abstracted from a paper by Dennis P. Ward and Andrew C. Meko of the Sargent & Lundy Company which was presented at the 1984 EPRI Life Extension Conference (entry 30 of the Bibliography).

Deciding which of the existing federal and state guidelines are applicable and just which modifications are subject to control can be a complicated task. Federal regulations generally apply to those modifications that increase air pollution emissions or cost more than 50% of the price of a new, comparable unit. The gray area is that those modifications typically included in the 50% test have been defined more on

Table 4.7 Summary of Environmental Regulations to be Considered During the Life Extension Evaluation Process

Federal Requirements	Considerations
New Source Performance Standards (air)	Standards apply if facility is new, modified, or reconstructed. The EPA applies these tests: new: boiler replacement modified: physical or operational changes that result in increased emissions reconstructed: fixed capital costs exceed 50% of the cost of a new steam generator
Prevention of Significant Deterioration (air)	Permit requirements apply to modifications for which net emissions increase exceeds "de minimus" limits
National Pollutant Discharge Elimination System (water)	New or modified permit required if point source discharge is modified
Environmental Impact Statement	Not required unless major renovation subject to federal licensing occurs
Corps of Engineers	Permit required for construction activity in navigable waters

State Requirements	Considerations
Air	New or modified construction and operating permits required "Bubble" policy may apply
Water and solid waste	New or modified construction and operating permits required

Source: Proceedings of EPRI Life Extension Conference, Washington, D.C., June 12-15, 1985.

industry experience rather than specific Environmental Protection Agency (EPA) definitions. The planning process is further complicated by the fact that some regulatory requirements depend on the extent of the modifications. The New Source Performance Standards (NSPS) are meant to apply primarily to newly constructed facilities, but they can also be applied to "modified" or "reconstructed" plants. There is still debate

within the utility industry as to the specific definitions of these descriptions. An additional consideration for utility planners is that state regulations can apply to most all modification programs and under the Clean Air Act can be more stringent than federal guidelines.

Ward and Meko offer the following environmental guidelines for life extension projects:

(a) Life extension projects that include capacity expansions are more likely to be subject to NSPS and Prevention of Significant Deterioration (PSD) or emission offset regulations because of the potential for increased air emissions. Air pollution control equipment in addition to that already installed at the existing plant may be required as part of state or federal air permits. Capacity expansions will also cause increased involvement in the project by the state PSCs.

(b) Projects that result in increased waste water discharges may be classified as new sources and therefore subject to National Pollutant Discharge Elimination System (NPDES) regulations. This could result in the requirement for new or modified treatment systems.

(c) Any increase in solid wastes could require new or enlarged solid waste disposal facilities.

By far the most uncertain environmental consideration is the acid rain legislation now under consideration. Even though final action on these bills is not expected soon, utilities would be prudent to consider the economic impact of meeting proposed SO_2 reductions. Utilities in affected areas should include options such as switching to a low sulfur coal or the installation of flue gas desulfurization systems as a part of the life extension economic evaluations.

4.2.6 Financial and economic considerations

Because of high interest rates and long construction lead times, financial considerations have become an important part of a utility's investment evaluation process. At the present time, new plant construction carries considerable financial risk including:

(a) the value of the construction project may exceed the combined assets of the utility,

(b) reduced bond rating and higher required return on stock,

(c) interest coverage ratios may fall to unacceptable levels, and

(d) recovery of the construction costs could be difficult due to public opposition to increased rates.

Unlike new construction, life extension projects have several financial advantages. These benefits result primarily from their modular nature and include:

(a) reduced construction expenditures due to their less capital intensive nature,

(b) reduced need for external financing due to reduced construction cost,

(c) improved interest and dividend coverage, quality of earnings, and construction work in progress due to the short lead times, and

(d) more flexibility to meet changing financial conditions.

This increased flexibility results from the modular nature of life extension projects. It has financial value in that it allows the utility to either accelerate or delay the project without serious adverse consequences.

As one might expect, economic considerations tend to be the primary constraint on implementing a life extension program. Virtually any amount of improvement and modernization is possible, for a price. The evaluation of life extension economic criteria most often occurs within an existing system planning model. These models vary among utilities and can utilize such measures of performance as present value, internal rate of return, and pay back period. Regardless of the specific procedure used, the most fundamental life extension economic analysis is a comparison of costs versus benefits. This format conveniently separates the required variables into components and thus facilitates this discussion of individual criteria.

The most complete treatments of upgrading and life extension cost—benefit economic analyses published to date are contained in entries 17 and 18 of the Bibliography. The following information is taken largely from these reports, and the reader is encouraged to consult them for details. The most basic framework for a cost-benefit analysis is shown in Figure 4.1. It indicates that the evaluation depends on six basic quantities: the displaced power cost, plant

ORNL-DWG 85-5330 ETD

SAVINGS = BENEFITS − COST

= (BENEFITS PER MWh × ΔOUTPUT) − COST

= (DISPLACED POWER COSTS − PLANT COSTS) (MW × HOURS × UTILIZATION × ΔEA) − COST

SOURCE: ECONOMIC EVALUATION OF PLANT-UPGRADING INVESTMENTS, VOLUME 1: SUMMARY REPORT, EPRI EA-3890, VOLUME 1, ELECTRIC POWER RESEARCH INSTITUTE, PALO ALTO, CALIFORNIA, 1985

Fig. 4.1. Framework for a typical life extension cost-benefit economic analysis.

modification costs, plant size, utilization and availability of the modified plant, and the change in the utility's direct and indirect costs. If a utility capitalizes the life extension expenditure, that too will affect savings.

Displaced power costs result when the unmodified unit is allowed to remain on stream and fails. This lost capacity must be purchased or made up from other units within the system. If the replacement power is to be supplied from within the utility, then the operation of the entire utility system becomes pertinent. Because system load, capacity mix, and fuel costs fluctuate over time, the particular plant defined as the marginal unit (the unit that must replace the lost capacity) also changes. Thus displaced power cost becomes a function of time, and calculating it requires a sophisticated analysis, a point often overlooked.

The actual cost of the life extension project depends on several factors. These include the amount of equipment modification and replacement, the length of the refurbishment period, the replacement power cost during refurbishment, and the amount of life extension. The equipment modifications depend on the anticipated service of the modified unit and the total number of units included in the program. Improving a single unit does not significantly improve the system's reliability or defer new capacity, but a company wide program involving several units can have such benefits. The amount of time necessary to accomplish the life extension and the non-capital costs incurred (e.g., cost of replacement power) directly influence the net savings and should be considered in the planning stages. The timing of the life extension

project relative to a plant's remaining life is also important. There is an optimum point where the improvement in plant availability and the time value of money combine to maximize savings.

The size of the plant and its post modification utilization factor as well as its change in equivalent availability are also pertinent decision criteria. All other considerations equal, a larger plant yields higher benefits, although costs will also likely be higher. The reduction in forced outage rate is one of the single most important planning considerations. Increasing plant reliability and reducing its operating costs are the purposes of the life extension project, and the degree to which this is accomplished directly influences net savings.

The change in the utility's direct and indirect costs must also be included in any economic evaluation. In addition to an initial capital outlay, implementing a life extension project requires a commitment to an elevated level of routine maintenance. This requirement will increase routine maintenance costs over traditional amounts. A cost increase also occurs when the utility capitalizes the total project cost rather than expenses it. Life extension is a long term effort and costs can be large; therefore it is not unusual to expect capitalization of costs. When total costs are financed, additional revenue requirements are required to pay for the investment. These extra charges are passed to the ratepayer and consist of depreciation, return on investment, and taxes.

4.2.7 Uncertainty

Uncertainty is a planning consideration that, while not unique to life extension, is appropriate to discuss here. It is especially important because life extension projects typically have long payback periods. There are both technical and financial uncertainties that should be addressed during the decision making process.

Technical risks unique to life extension include uncertainty about just how much availability improvement can be realized and the level of effort required to implement a life extension project. Until several projects have been completed, the actual degree of renovation required

to achieve a 20 year life extension cannot be accurately defined. It is a fact of industrial life that no amount of planning can define the duration or complete cost of a retrofit effort in advance. The financial and economic risks associated with life extension are similar to those of any other large, capital intensive project. Load growth, fuel cost, the cost of money, replacement power costs, construction delays, the actual reduction in operating costs realized, and the required rate of return all contribute to economic uncertainty.

In the last few years, simulation models utilizing probabilistic techniques have been developed to deal with planning uncertainties. Combined with frequent reevaluations of the planning variables, these computer models are superior to traditional deterministic procedures for quantifying risk. The subject of utility planning in uncertain times is discussed in entry 3 of the Bibliography.

5. ECONOMIC CONSIDERATIONS

This section of the report summarizes the economic and regulatory experiences of some actual life extension programs. This type of information is required so that a nominal life extension program can be defined. The programs summarized herein were identified through the open literature and vendor contacts but should not be considered a definitive list. To date there has not been a concerted effort within the utility industry to assess the extent of fossil-fueled life extension activity. The Edison Electric Institute has tentative plans to conduct such a survey in calendar year 1986, and at that time a more complete summary can be made.

5.1 Summary of Selected Life Extension Projects

A brief summary of current life extension program experience to date is contained in Table 5.1. It is apparent that both the concept and implementation of these programs vary considerably. Not unexpectedly, the cost data also varies considerably. To avoid confusion in understanding the cost data, it will be necessary to address the different types of life extension programs.

Table 5.1. Summary of some current life extension programs

Utility	NCM region	Status summary
Arizona Public Service	40	Just now starting scoping studies. No inspections, schedules, or costs have been defined yet. Pending acid rain legislation treated as another planning uncertainty.
Atlantic City Electric	4	Gradual implementation. Have started mechanical inspections on Deepwater #6 and B. L. England units. Additional inspections scheduled next two calendar years. To date have spent $5 million on turbine-generator of Deepwater #6. No total cost figures have been made yet. Pending acid rain legislation treated as any other planning uncertainty.
Carolina Power & Light	11	No formal effort. Program consists of extensive, continuing component by component mechanical inspection and remaining life analysis. Correct any problems as they arise. No total cost figures have been made. Pending acid rain legislation treated as any other planning uncertainly.
Cincinnati Gas & Electric	22	Intensive implementation. W. C. Beckjord #3 currently down for modifications, to be finished 1/31/86. W. C. Beckjord #1 scheduled for Fall of 86, W. C. Beckjord #2 scheduled for Fall of 87. Capital cost projections are. W. C. Beckjord #3 about $11 million, #1 about $9 million, and #2 about $12 million. Pending acid rain legislation did not significantly affect life extension decision. Have not tried to obtain state PSC approval for recovery of costs at this time.
Cleveland Electric Illuminating	20	Just starting mechanical inspection phase. Have not made a firm decision of life extension at this time. No cost figures have been defined yet.
Consumers Power	23	Just starting on advanced planning and mechanical inspections. No cost figures have been defined yet.
Dayton Power & Light	22	Cannot justify life extension at this time due to low load and less expensive power purchases. Have defined necessary modifications for Hutchings #1-6. Cost figures are considered business confidential.
Delmarva Power	10	Gradual implementation. Have partially completed mechanical inspections on 3 units and will continue them next calendar year. Will make necessary modifications in conjunction with routine maintenance. No total cost figures have been defined to date. Pending acid rain legislation did not significantly affect life extension decision.
Detroit Edison	23	No formal program. Have steadily increased O&M and capital expenditures since 1974 to maintain nominal performance. Pending acid rain legislation treated as another planning variable. Increased costs have been allowed by the state PSC.
Duke Power	11	Intensive implementation. Dan River #1,2,3 have been completed at approximate cost of $225/kW(e). Mechanical investigations scheduled for Allen, Lee Station, Riverbend, Buck, and Cliffside units. These units will probably be modified using both routine and special outages. Only projected costs currently available are for Allen #1 and are $41/kW(e) for capital only. Total estimated cost for Allen #1 is $365/kW(e) including O&M over extended lifetime. Pending acid rain legislation treated as another planning uncertainty. State PSC ruled Dan River modifications as cost effective and allowed them into the rate base.
Iowa Public Service	32	No firm decision on implementing a program has been made. Are starting mechanical inspection of Neal #1.
Jersey Central	4	Gradual implementation. Inspection of three units in progress. No schedules or cost figures have been defined yet. Pending acid rain legislation treated as another planning uncertainly.

Table 5.1 (Continued)

Utility	NCM region	Status summary
Kansas City Power & Light	33	Just now starting scoping studies. No inspections, schedules, or costs have been defined yet. Pending acid rain legislation treated as another planning uncertainty.
Metropolitan Edison	5	Gradual implementation. Inspections complete and work started on Portland and Titus stations. Cost figures are considered business confidential. Pending acid rain legislation treated as another planning uncertainty.
Minnesota Power	27	Starting mechanical inspections. No cost figures have been defined yet. Pending acid rain legislation treated as another planning uncertainty.
Niagara Mohawk	3	Gradual implementation. Only now starting mechanical inspections. Huntly #6-7 has been completed, and will start on remaining nine units early in CY-86. Plan to modify critical systems first then come back to balance of plant. No total cost figures have been defined yet. Meeting any pending acid rain legislation will be a part of economic evaluations.
Northern States Power	34	Combined intensive and gradual implementation. To date have increased the capacity and extended Riverside Station at a cost of $57 million. Additional work on coal system to be completed soon. Total costs not yet available. Currently doing advanced planning on another 8 units. Pending acid rain legislation treated as any other planning uncertainty. Riverside station costs were allowed by the state PSC.
Ohio Edison	20	Just beginning mechanical inspections and have completed 11 of 25. Will define their program when these are finished. Preliminary capital cost estimate is $60—90/kW(e). Pending acid rain legislation treated as another planning uncertainty.
Pennsylvania Electric	5	Gradual implementation. Mechanical inspections complete on Frontstreet, Williamsburg, and Warren stations. No schedules or cost have been defined yet. Pending acid rain legislation treated as any other planning uncertainty.
Pennsylvania Power & Light	5	Gradual implementation. Currently inspect all 13 coal-fired plants on 5 year rotating cycle. Have committed $50 million to date and have the potential for additional $175 million. Pending acid rain legislation treated as another planning variable. Early costs only partially allowed by state PSC.
Philadelphia Electric	5	Gradual implementation. Plan to keep Eddystone #1,2 and Cromby #1 on line for extended period. No total costs have been defined yet. Pending acid rain legislation treated as another planning uncertainty.
Potomac Electric Power	10	Gradual implementation. Currently modifying Potomac River Station. Have $80 million budgeted and have spent $20 million to date. No total program costs have been defined yet. Pending acid rain legislation treated as another planning uncertainty. Costs have been allowed by the state PSC.
Public Service Colorado	38	Just beginning mechanical inspections. Do not have an established program or cost figures defined yet. Pending acid rain legislation treated as another planning uncertainly.
Public Service of Indiana	25	Just beginning mechanical inspections. Have completed 1 of 3 scheduled inspections and will make formal plans when all 3 are through. No total cost figures have been defined yet. Pending acid rain legislation treated as another planning uncertainty.

Table 5.1 (Continued)

Utility	NCM region	Status summary
Southern Company Services	12,19	Have commitment to keep existing units running for extended periods. At this time they have no formal program and no immediate plans to implement one.
Tennessee Valley Authority	Several	Just now starting life extension program. Have completed scoping study on Kingston #1. No total cost figures have been defined yet. Pending acid rain legislation treated as another planning uncertainty.
Utah Power & Light	37	Gradual implementation over the next 10 years. Have partially inspected and begun modifications on 3 plants. Project 10 year average cost of $200/kW(e). Pending acid rain legislation treated as another planning uncertainty.
Virginia Electric & Power	9	Just now starting life extension program. Have completed mechanical inspection on a single unit and will begin economic analysis soon. No total cost figures have been defined yet. Pending acid rain legislation treated as another planning uncertainty.
Wisconsin Electric Power	26	Gradual implementation. Completed inspection on Port Washington Station #1-4. Work to begin late 86-yearly 87. Total estimated cost is $80 million. Pending acid rain legislation is treated as another planning uncertainty. No costs have been recovered yet but initial reaction of state PSC is favorable.
Wisconsin Public Service	26	Gradual implementation. Program is designed to maintain nominal availability levels through the original design life. No firm costs have been designed yet. Pending acid rain legislation treated as another planning uncertainty.

The most prominent fact established is that the majority of utilities are only now beginning their programs. Of the 30 companies examined, only 9 have progressed beyond the initial inspection phase and started equipment modifications. An additional complication is that most utilities are not treating life extension as a discrete event. They have already, or intend to, implement their programs gradually, in close coordination with their routine maintenance outages. This differs considerably from the common perception of life extension as an intensive replacement and modernization effort followed by a relatively undisturbed extended operating period. Only two companies, Duke Power and Cincinnati Gas & Electric, have chosen the intensive approach. The consensus of opinion from the other 28 utilities was that a gradual replacement is more cost effective for those plants which are still good performers. There are two variations of the gradual implementation scheme that further complicate cost reporting. With one approach the program is fairly well defined in advance, and in the other equipment modifications are scheduled based on a series of continuing mechanical inspections. A third operating philosophy encountered is one in which utilities have gradually increased their annual operating and maintenance and capital investment expenditures to maintain their plants' existing performance. While this approach is not normally considered life extension, it does have the long term benefit of allowing plants to operate past their original design life. Carolina Power & Light and Detroit Edison are two companies that are implementing this type of program.

These circumstances combine to produce an inconclusive cost experience. There is only a very limited amount of data available for analysis. A specific complication is that two types of costs are being reported: total expenditures and amounts spent to date. Those utilities with intensive or well planned gradual programs are able to report total costs while those with gradual programs keyed to a series of continuing inspections can only give amounts spent to date. The situation is made even more difficult because of inconsistencies in the way costs are reported within these two categories. These additional complications

are:

(a) only one of the total cost figures quoted represented actual experience,

(b) some total costs contain only capital investment costs and others include both capital expenditures and incremental O&M costs, and

(c) when amounts spent to date are given, they are not expressed in the same year dollars.

Only 8 utilities reported any cost data. Four of these were classified as totals and 4 as cumulative amounts to date. Two companies, Dayton Power & Light and Metropolitan Edison, considered their cost estimates as business confidential. Using this limited data, a range of $41/kW(e) to $100/kW(e) was defined for total capital expenditures only. A second range was also defined which includes the total O&M expenses estimated for the extended operating period. These amounts varied from $225/kW(e) to $365/kW(e). In all of this data (i.e., both ranges) only one figure is based on actual experience. The $225/kW(e) amount was reported by Duke Power represented the total (i.e., capital and estimated O&M) investment for the Dan River Station.

The utilities pursuing the gradual approach have together spent more than $173 million on capital improvements in the last few years. In addition there are near term plans for an additional $360 million. There is no estimate for the modifications that will be made in the future as a result of the continuing mechanical inspections. The Northern States Power Company, for example, has spent $57 million to date for capital improvements at the Riverside Station. This does not include, however, the pulverized coal system which is still undergoing its initial inspection. Another example of a utility with currently undefined costs is the Atlantic City Electric Company. They are currently inspecting their Deepwater #6 unit and B. L. England station and so far have spent only $5 million for turbine-generator work at one station. Thus, as these inspections are completed, it is probable that a great deal more money could be spent.

Those utilities opting for increased annual expenditures to maintain performance levels do not specifically identify life extension costs and therefore cannot contribute to the cumulative experience. The

Detroit Edison Company is a good illustration of this approach in that they have more than doubled their annual capital and O&M budgets (in constant dollars) since 1974. It must be recognized that these types of programs have the potential to significantly affect the average age of the national plant population. Accordingly, they should be included in any future effort to define the impact and costs of life extension programs.

All but one utility indicated that future costs resulting from pending acid rain legislation were not a specific consideration in their planning activities, and that any new requirements would be factored into their economic analyses when, and if, they became law. If at that time life extension prove to be uneconomical, then alternate generating schemes would be considered. Only Niagara Mohawk indicated that its current life extension economic analyses included costs for meeting nominal acid rain environmental requirements.

5.2 Regulatory Treatment of Life Extension Costs

Even though only a few life extension programs have progressed to the point of being allowed to recover costs, the experience to date is quite favorable. Not unexpectedly, the experience base is quite limited and consists of only 5 companies: Detroit Edison, Duke Power, Northern States Power, Pennsylvania Power & Light, and Potomac Electric. In each case, if the expenditures were shown to be cost effective, they were allowed. Those few requests that were denied or only partially allowed were due to insufficient information or because they were submitted with other, much larger projects. A request by the Pennsylvania Power & Light Company was initially rejected because insufficient data was presented to prove the expenditures were cost effective. The company plans to resubmit with the necessary additional information, and they are confident it will then be approved. Duke Power's costs for their Dan River Station were only partially approved because they were included in a request with a nuclear plant.

Because the results of this study could not be considered representative, two national bodies were contacted in an effort to define a cost

recovery consensus. These were the National Regulatory Research Institute (NRRI) and the National Association of Regulatory Utility Commissioners (NARUC). Both indicated that their organizations had not done any work on how the state PSCs were treating life extension costs. It was their opinion however that if the expenditures were cost effective, they would be allowed in the rate base. These opinions together with the experience summarized above would seem to indicate that life extension costs will be treated as any other capital improvement program.

As was the case with the cost data in the preceding section, there proved to be insufficient information to adequately address the impact of life extension costs on electricity prices. Four of the 5 utilities that had recovered costs were implementing gradual programs, and therefore any one request and subsequent increase was relatively small. The only intensive program completed to date also contributed little to the eventual rate increase. As explained, Duke Power had requested the total costs of their Dan River Station life extension program together with the costs of one of their large nuclear stations. The size of the life extension costs relative to the nuclear plant were such that they contributed little to the resulting price increase. At this time it is not possible to predict what impact life extension will have on an individual utility's future price increases. Until more data is available concerning the total number of programs, their scope, costs, and financing plans, it will not be possible to make any kind of realistic projections. However, based on information available to date, it appears that costs of life extension programs are having minimal effects on rates. On the other hand, if life extension programs involving replacement of major equipment (i.e., steam generators and turbines) are implemented on a wide scale, there exists a potential for some rate increases.

6. CONCLUSIONS AND RECOMMENDATIONS

The information summarized in Section 4 shows, quite clearly, that the life extension decision making process is a very involved, extremely utility specific procedure. Life extension is not an automatic choice, and the type of program (i.e., number of plants, the particular plants

chosen, extent of modification) can vary greatly among utilities. Thus, it is not practical to expect that a simplified, all inclusive set of plant selection guidelines can be prepared. However, some generalizations are required. Given that simplification of the actual decision making process is not realistic, it is recommended that the plant selection criteria required as input to EIA computer models be based on actual industry experience. Accordingly, a set of recommendations is defined in the following paragraph. It is recognized that this empirical approach has limited accuracy and is subject to change as life extension becomes more common.

Two prominent conclusions can be drawn from the summary of current industry experience in Section 5:

(a) The majority of utilities are modifying their plants gradually over time, rather than all at once. Thus, the concept of life extension as a discrete event with distinctly different "before and after" plant configurations and operating characteristics is invalid.

(b) Plant life extension programs are just now being implemented on any kind of scale. Accordingly, there is insufficient data with which to define detailed, national trends.

These results, as well as the complex decision making process described in Section 4, combine to make highly uncertain any quantitative recommendations such as plant selection criteria, typical changes in plant performance after a life extension program, program costs as a function of coal type and DOE region, and cost profiles (i.e., costs of modifying major subsystems) as a function of plant size and amount of life extension. However, some very speculative guidelines can be defined. Accordingly, the following recommendations are made:

(a) Those coal-fired plants 25 years and older, between 100 MW(e) and 700 MW(e) in size should be selected for life extension programs.

(b) A life extension program will extend the operation of a coal-fired plant by 20 years and will cost $75/kW(e) in 1985 dollars for capital equipment improvements only. This amount can be spent as a lump sum when the life extension program is implemented as a discrete event or in five equal payments of $15/kW(e)-year when the program is to be implemented gradually. An additional cost of $10/kW(e)-year should be

used when it is desired to account for annual O&M expenditures during the extended operating period. Increased O&M expenditures after a life extension program are necessary to operate a more sophisticated system and to maintain the plant's increased availability.

(c) The post improvement performance of a plant can be determined from the historical performance data summarized in Section 3. As a first approximation, it is reasonable to assume that a life extension program will return the plant's performance to that when it was new. The curve fits that were supplied with the performance data presented as a function of year of operation can be used to calculate these performance levels.

BIBLIOGRAPHY

1. Anson, D., *Availability Patterns in Fossil-Fired Steam Power Plants*, EPRI FP-583-SR, Electric Power Research Institute, Palo Alto, California, 1977.

2. Hudson II, C. R., *Age and Capacity Profile of Electric Generation Plants in the United States*, ORNL/TM-8510, Oak Ridge National Laboratory, Oak Ridge, Tennessee, 1983.

3. Fiore, D. D., Kettler, D. J., and Nobile, P. A., "Conditions for System Planning in This Uncertain Time," Presented at EBASCO Services Incorporated Fifty Fourth Annual Executive Conference, Tucson, Arizona, 1983.

4. Cagnetta Jr., A. C., Mora, J., Connell, J. M., Rao, R., and Andonedis, A., "Optimizing Capacity and Performance of Existing Fossil Units," Presented at EBASCO Services Incorporated Fifty Fourth Annual Executive Conference, Tucson, Arizona, 1983.

5. Cavanaugh, H. A., "Capacity Additions: How much? How Soon?," *Electrical World*, January 1985.

6. Armor, A. F., "Efficiency Improvement in Fossil-Fired Power Plants," Presented at the Joint Power Generation Conference, Indianapolis, Indiana, 1983.

7. Reisdorf, J. B., Wainwright, R. M., and Sebesta, J. J., "Economic Impact of Availability for a 500 MW Power Plant," *Proceedings of the American Power Conference*, Volume 47, Chicago, Illinois, 1985.

8. Jewell, P. R., Stoll, H. G., Szczepanski, R. S., and Tice, J. B., "Trends in Generating Unit Availability and Their Impact on Reserve Margins," *Proceedings of the American Power Conference*, Volume 41, Chicago, Illinois, 1979.

9. Lafontaine, J. K., Craft Jr., R. E., Dore, B. L., and Grant, W. S., "Generating Station Availability Improvement Program," *Proceedings of the American Power Conference*, Volume 47, Chicago, Illinois, 1985.

10. "35th Annual Electric Utility Industry Forecast: Economic Recovery Drives kWh Sales Up," *Electrical World*, September, 1984.

11. Armor, A. F., Scheibel, J. R., Dooley, R. B., and Parkes, J. B., "A Strategy for Fossil Power Plant Life Extension," *Proceedings of the American Power Conference*, Volume 47, Chicago, Illinois, 1985.

12. Stoll, H. G., and Heiges, H. H., "The Benefits of Power Plant Life Extension in Today's Utility Business Climate," *Proceedings of the American Power Conference*, Volume 47, Chicago, Illinois, 1985.

13. "Extending the Lifespan of Fossil Plants," *EPRI Journal*, June, 1983.

14. Braun, Chaim, "Economic Factors Related to Life Extension of Nuclear and Coal Fired Power Plants," Presented at the American Nuclear Society Annual Meeting, New Orleans, Louisiana, 1984.

15. Papamarcos, J., "New Generating Plants: When, Where, and by Whom," *Power Engineering*, April, 1985.

16. Le, K. D., and McCutchan, D. A., "What is the Worth of Baseload Availability?," *The Engineering Economist*, Volume 26, Number 2, 1981.

17. *Economic Evaluation of Plant-upgrading Investments, Volume 1: Summary Report*, EPRI EA-3890, Volume 1, Electric Power Research Institute, Palo Alto, California, 1985.

18. *Economic Evaluation of Plant-upgrading Investments, Volume 2: Case Studies*, EPRI EA-3890, Volume 2, Electric Power Research Institute, Palo Alto, California, 1985.

19. "Pennsylvania PUC Proposes Incentives for Utilities to Upgrade Coal Units," *Electric Utility Week*, August 26, 1985.

20. Generating Unit Reference File, Oak Ridge National Laboratory, Oak Ridge, Tennessee, 1985.

21. Generating Availability Data System, North American Electric Reliability Council, Princeton, New Jersey, 1985.

22. Foster, J. L., Penland, J. R., Roll Jr., C. R., and Hedges, K. A., *Case Studies of Plant Demographics: Efficiency and Availability Enhancements*, Science Applications, Incorporated, McLean, Virginia, January, 1983.

23. Makansi, J., "Upgrading Steam and Gas Turbines: Overcoming Today's Operating Constraints," *Power*, March, 1985.

24. Stoll, H. G., "Economic Evaluation Procedures for Turbine-Generator Upgrading," *Power Generation Engineering Report #167*, General Electric Company, Schenectady, New York, 1983.

25. Rittenhouse, R. C., "Diagnostics for Operation, Maintenance and Upgrading," *Power Engineering*, March 1985.

26. Czeratzki, A., Busse, L., and Stys, Z. S., "Remaining Useful Lifetime of Older Steam Turbines," *Proceedings of the American Power Conference*, Volume 45, Chicago, Illinois, 1983.

27. Willis, Jr., C. B., "Boiler Upgrading", *Heat Engineering*, Foster Wheeler Corporation, Livingston, New Jersey, January-March 1984.

28. Ernest, C. R., Fischetti, J. W., and Wilson, W. H., "Upgrading - A Way to Extend the Life of Turbine - Generator Units," *Proceedings of the American Power Conference*, Volume 45, Chicago, Illinois, 1983.

29. Mazzarell, G. R. and Krueger, C. H., "Upgrading - Uprating to Achieve Availability and Economical Capacity," *Proceedings of the American Power Conference*, Volume 45, Chicago, Illinois, 1983.

30. Scheibel, J. R., Draft Proceedings of EPRI Life Extension Conference, Washington, D.C., June 12-15, 1984.

31. Ernest, C. R., Fischetti, J. W., and Nock, H. T., "New Life for Long-Service Turbine Generators, *Electric Forum*, Volume 9, Number 1, 1983.

32. Davis, K., Hunter, J. S., and King, J. P., "Boiler Life Extension-A New Lease on Life," *Proceedings of the American Power Conference*, Chicago, Illinois, Volume 47, 1985.

33. United Engineers & Constructors, "Presentation on the Construction of Coal-Fired Generating Units," Sponsored by the Electric Power Division, Energy Information Administration, Washington, DC, June 12, 1984.

34. *Steam*, The Babcock and Wilcox Company, New York, New York, 1972.

Appendix

PLOTS OF COAL-FIRED POWER PLANT HISTORICAL PERFORMANCE TRENDS

ORNL-DWG 85-5218 ETD

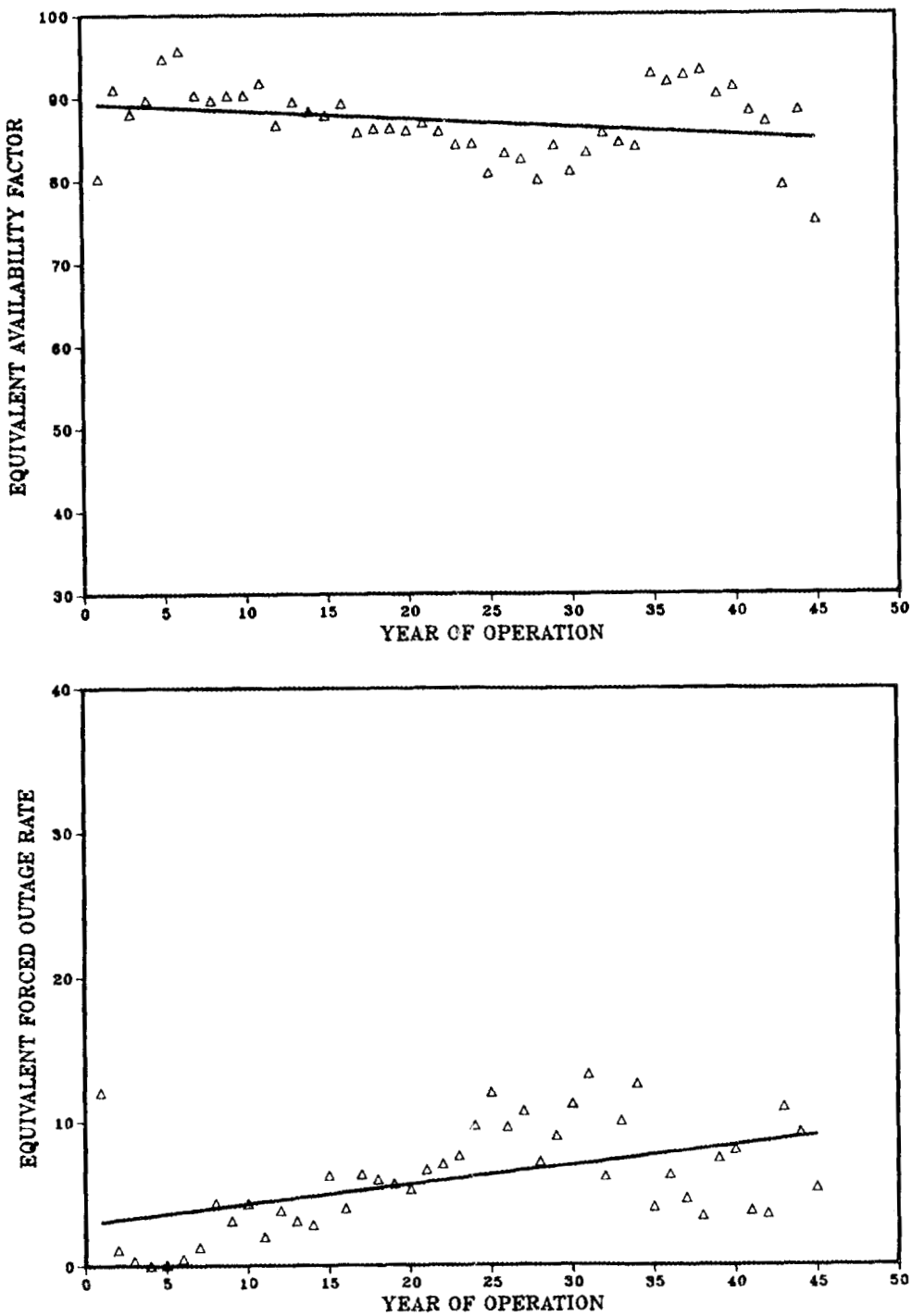

Fig. A.1. Average equivalent forced outage rate and equivalent availability factor as a function of year of operation for the 1-99 MW(e) size range.

ORNL-DWG 85-5219 ETD

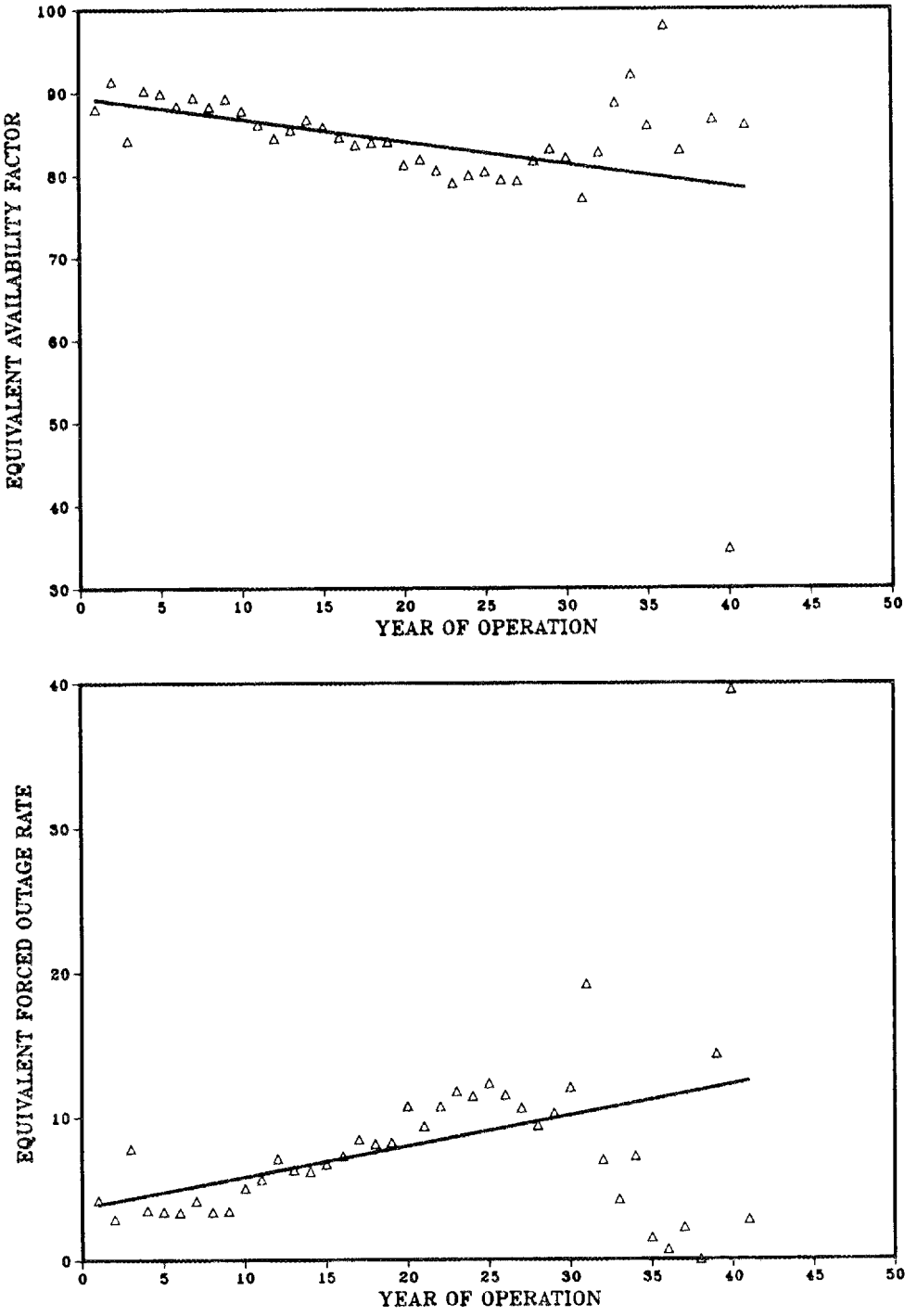

Fig. A.2. Average equivalent forced outage rate and equivalent availability factor as a function of year of operation for the 100-199 MW(e) size range.

ORNL-DWG 85-5220 ETD

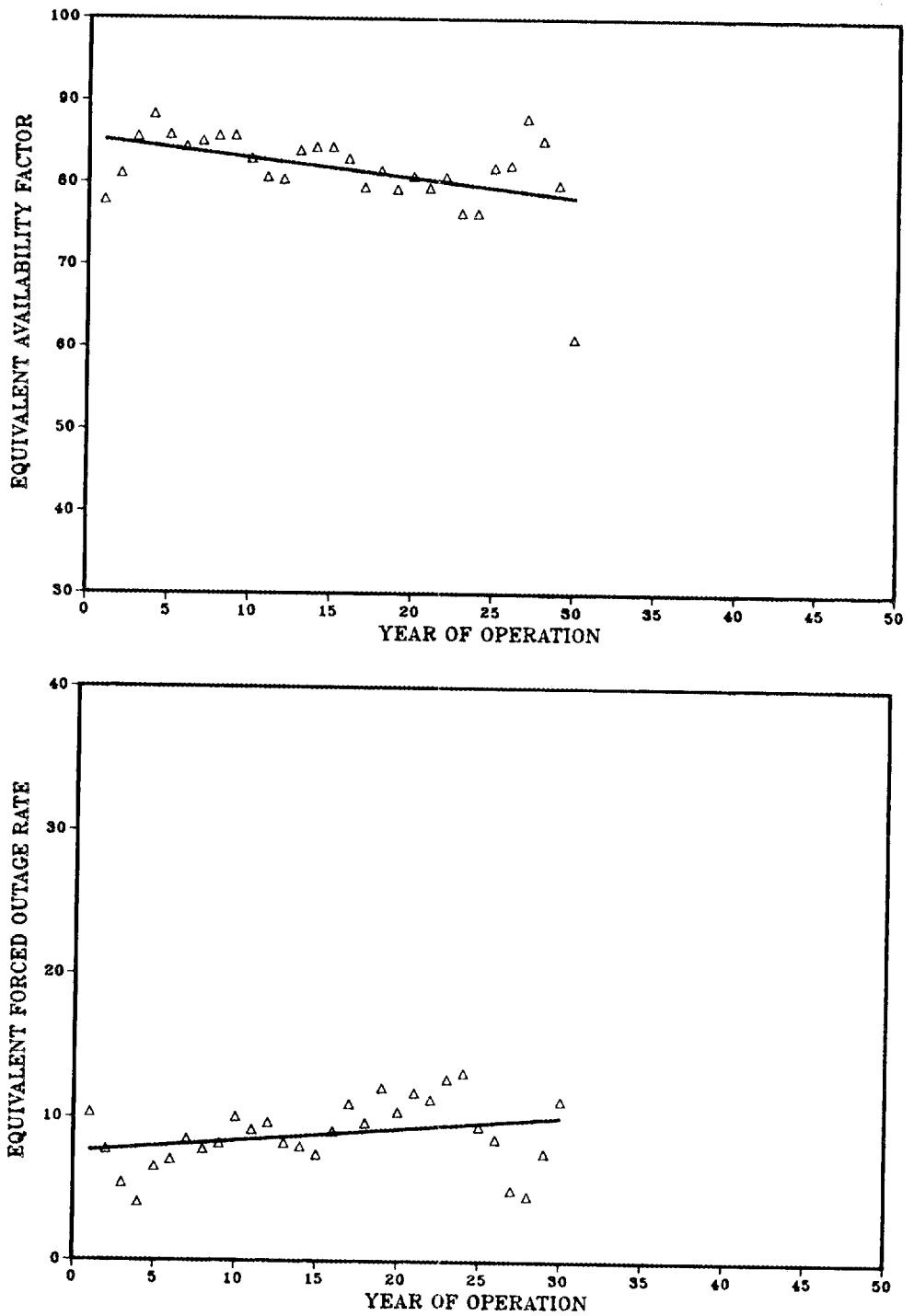

Fig. A.3. Average equivalent forced outage rate and equivalent availability factor as a function of year of operation for the 200-299 MW(e) size range.

ORNL-DWG 85-5221 ETD

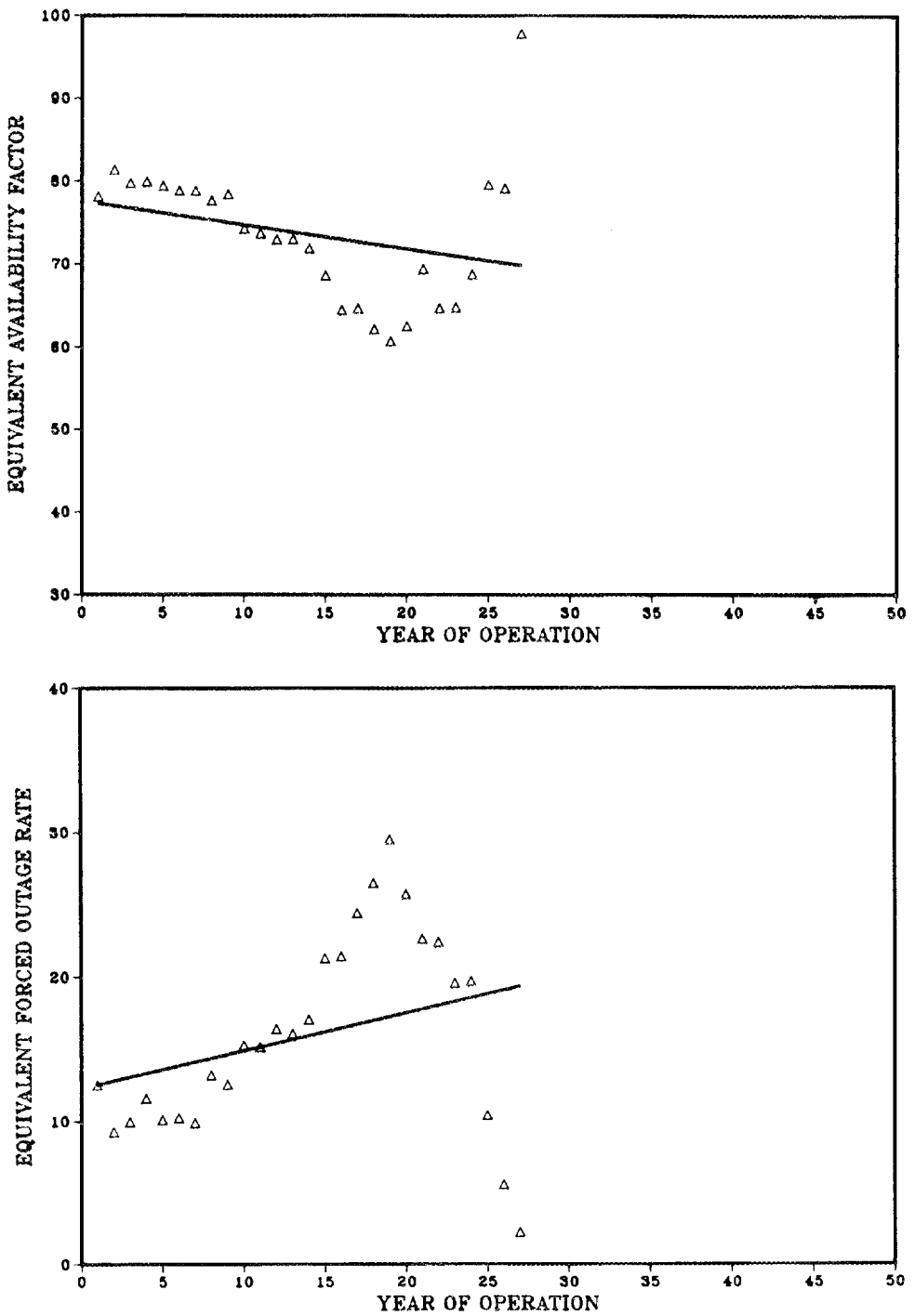

Fig. A.4. Average equivalent forced outage rate and equivalent availability factor as a function of year of operation for the 300-399 MW(e) size range.

ORNL–DWG 85–5222 ETD

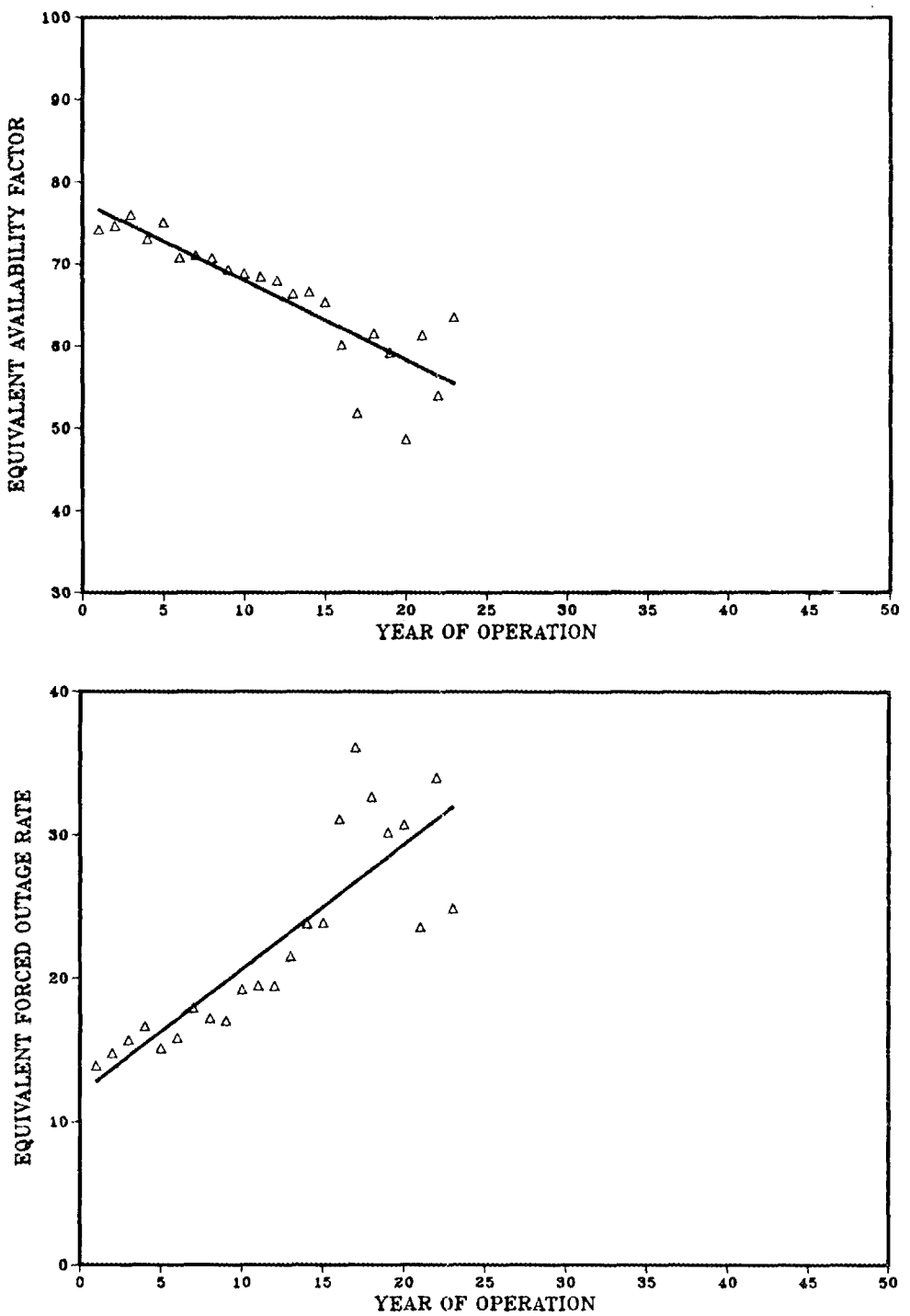

Fig. A.5. Average equivalent forced outage rate and equivalent availability factor as a function of year of operation for the 400-599 MW(e) size range.

ORNL-DWG 85-5223 ETD

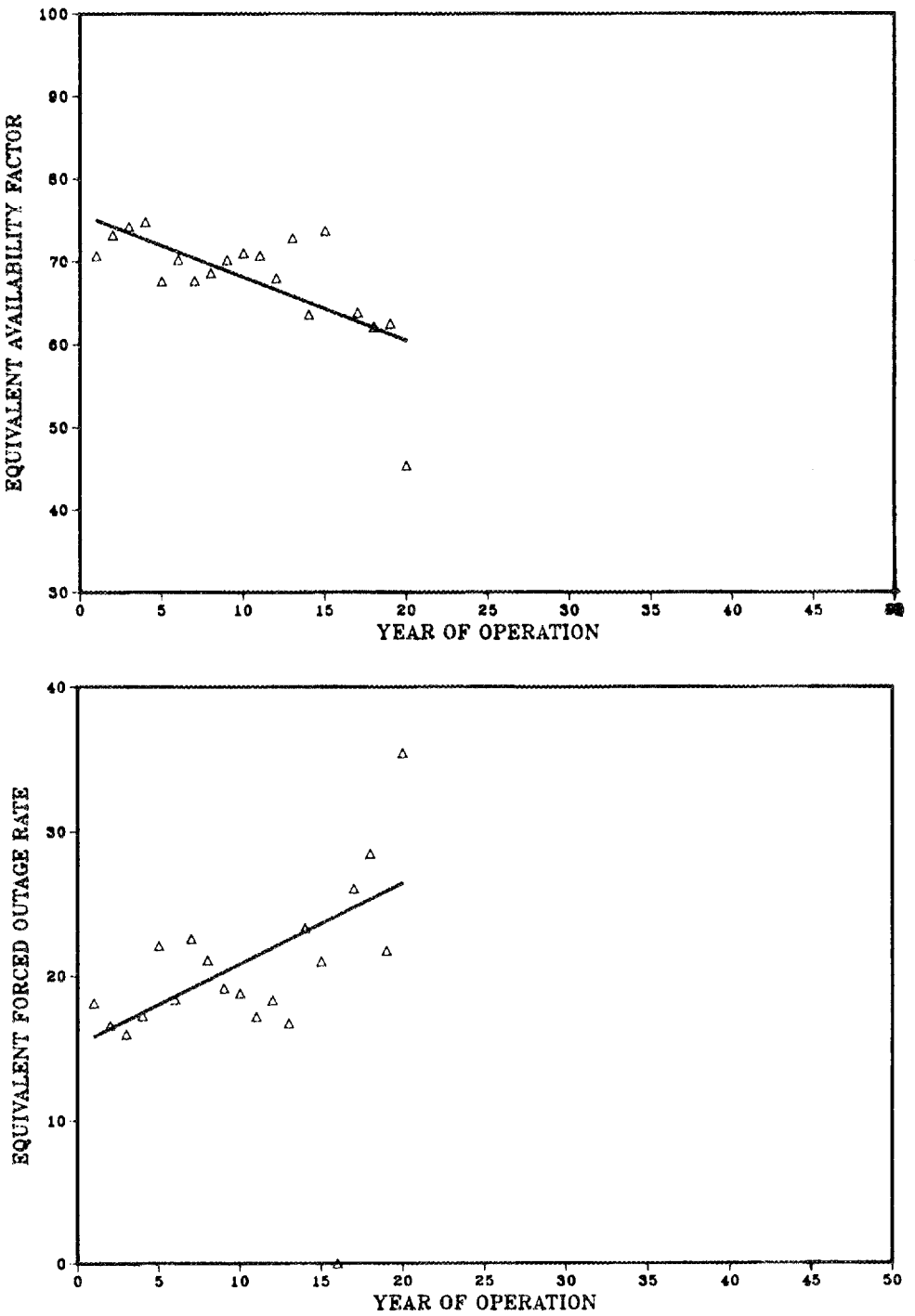

Fig. A.6. Average equivalent forced outage rate and equivalent availability factor as a function of year of operation for the 600-799 MW(e) size range.

ORNL--DWG 85--5224 ETD

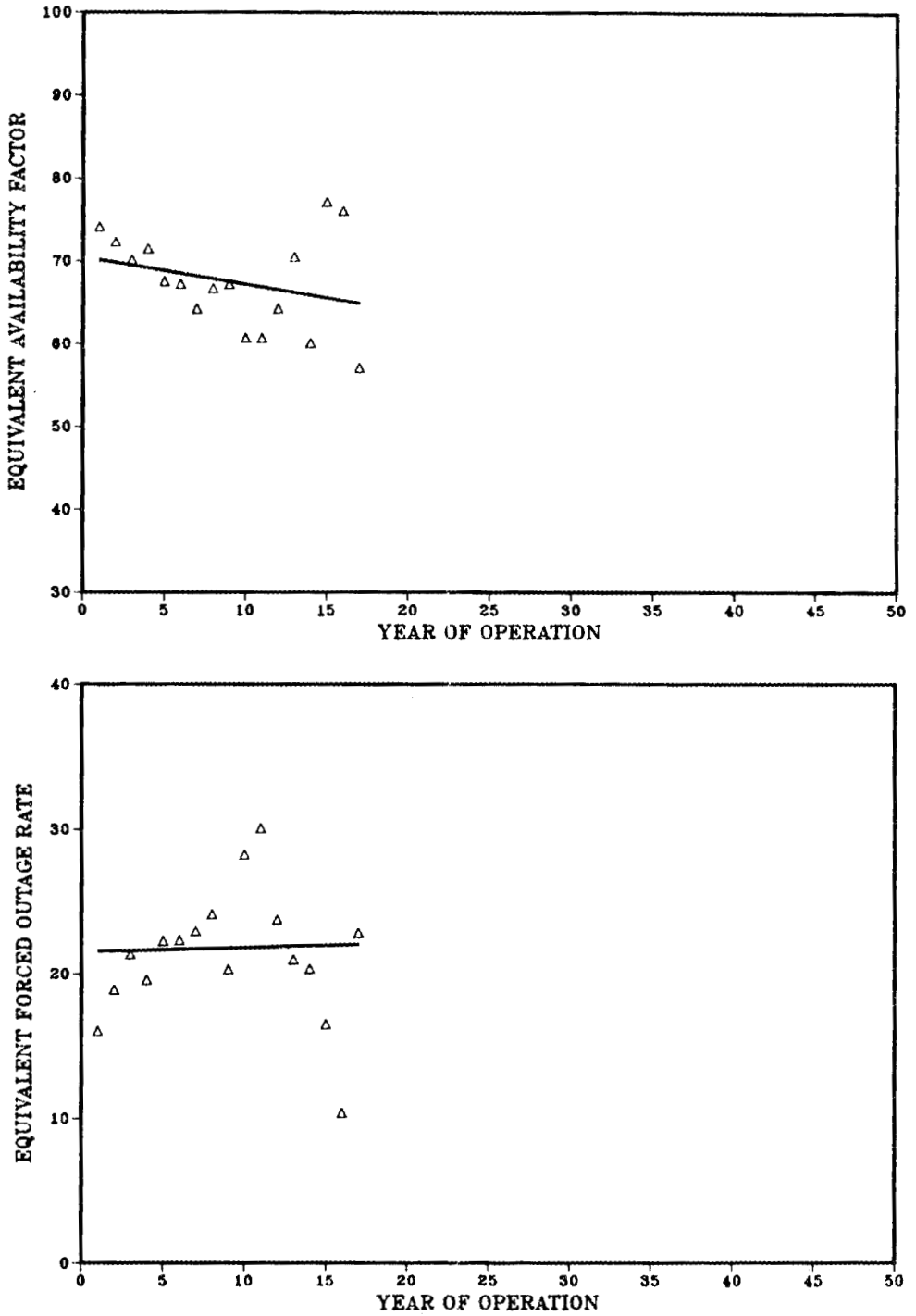

Fig. A.7. Average equivalent forced outage rate and equivalent availability factor as a function of year of operation for the > 800 MW(e) size range.

ORNL-DWG 85-5211 ETD

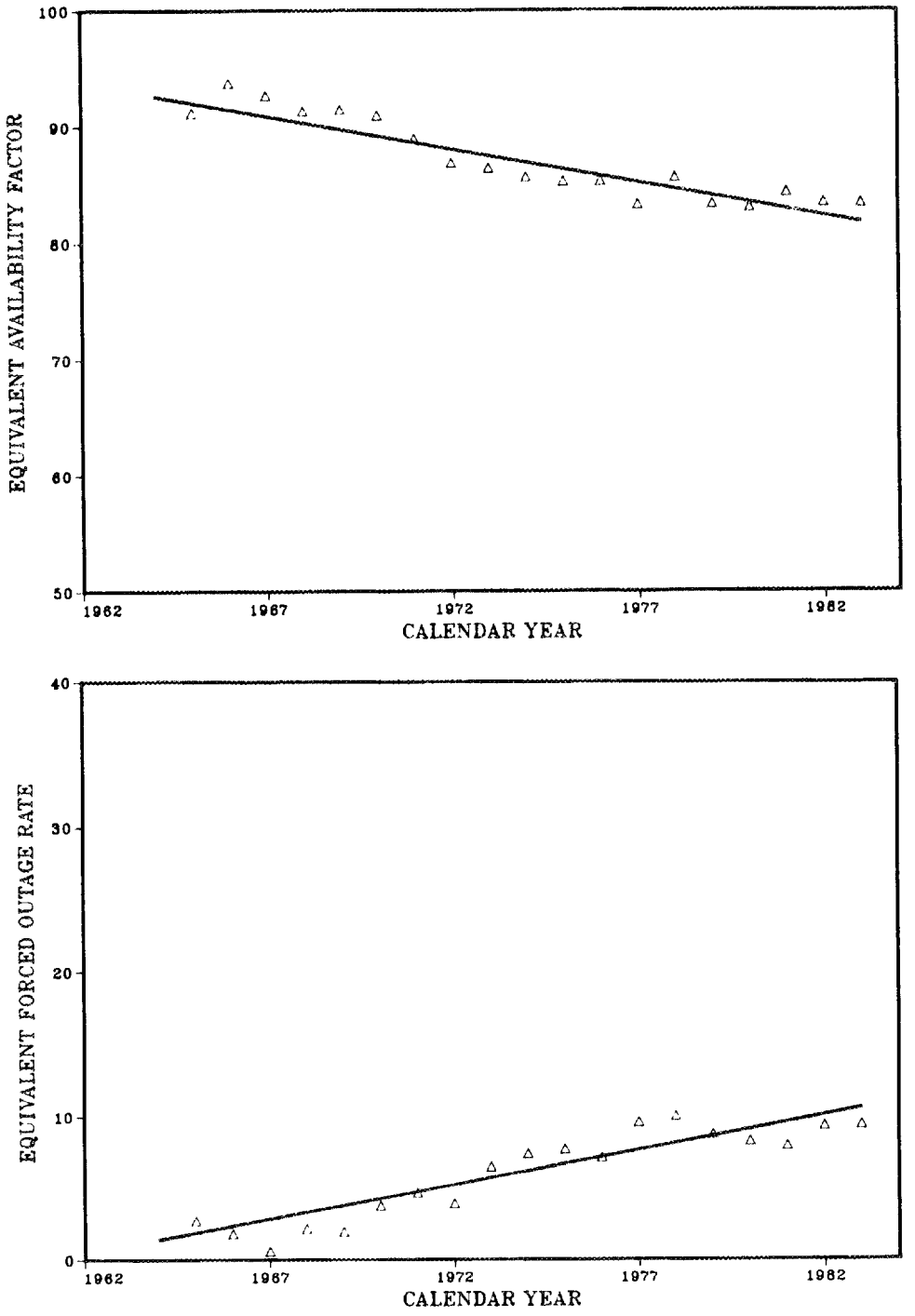

Fig. A.8. Average equivalent forced outage rate and equivalent availability factor as a function of calendar year of operation for the 1-99 MW(e) size range.

ORNL-DWG 85-5212 ETD

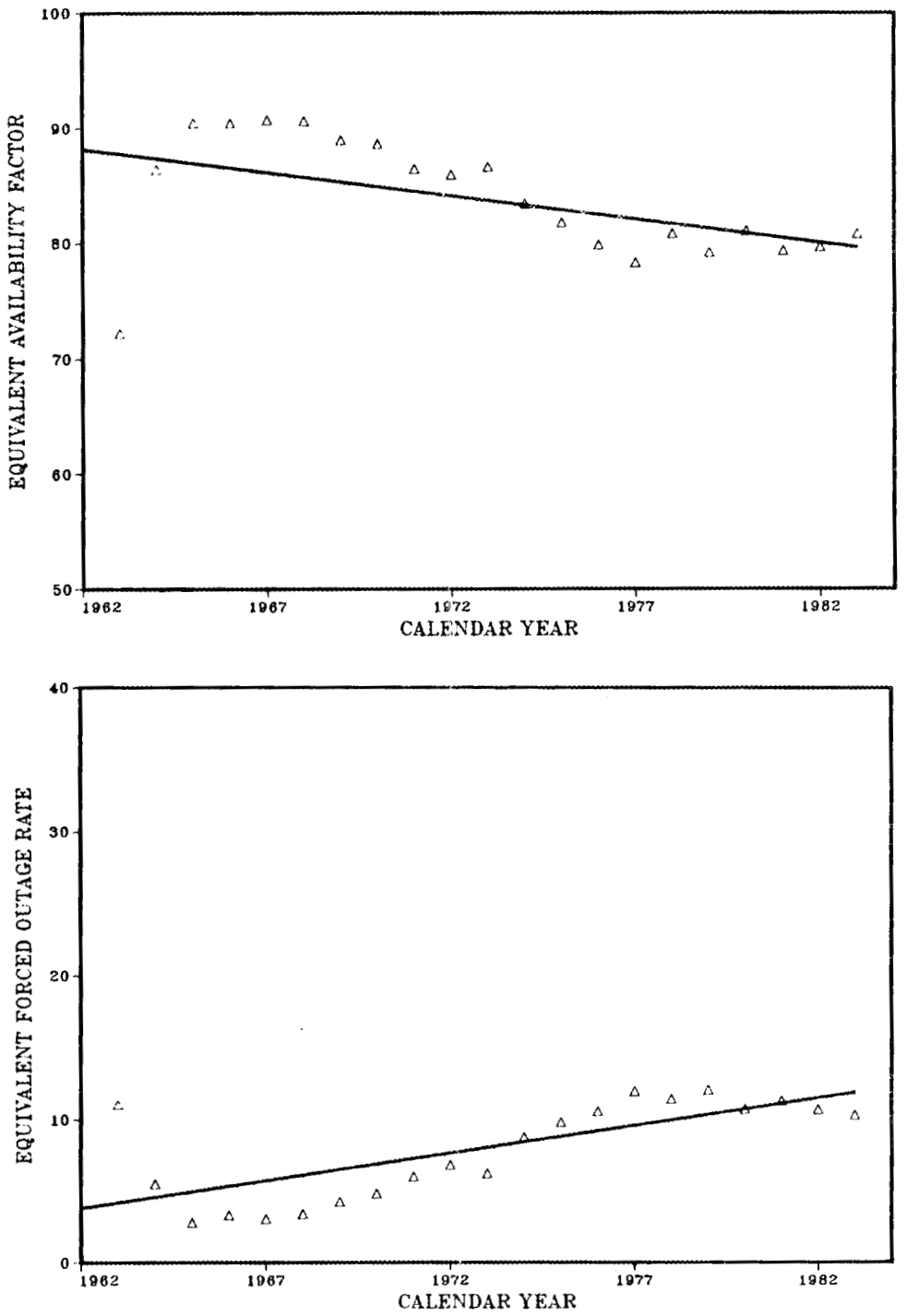

Fig. A.9. Average equivalent forced outage rate and equivalent availability factor as a function of calendar year of operation for the 100-199 MW(e) size range.

ORNL-DWG 85-5213 ETD

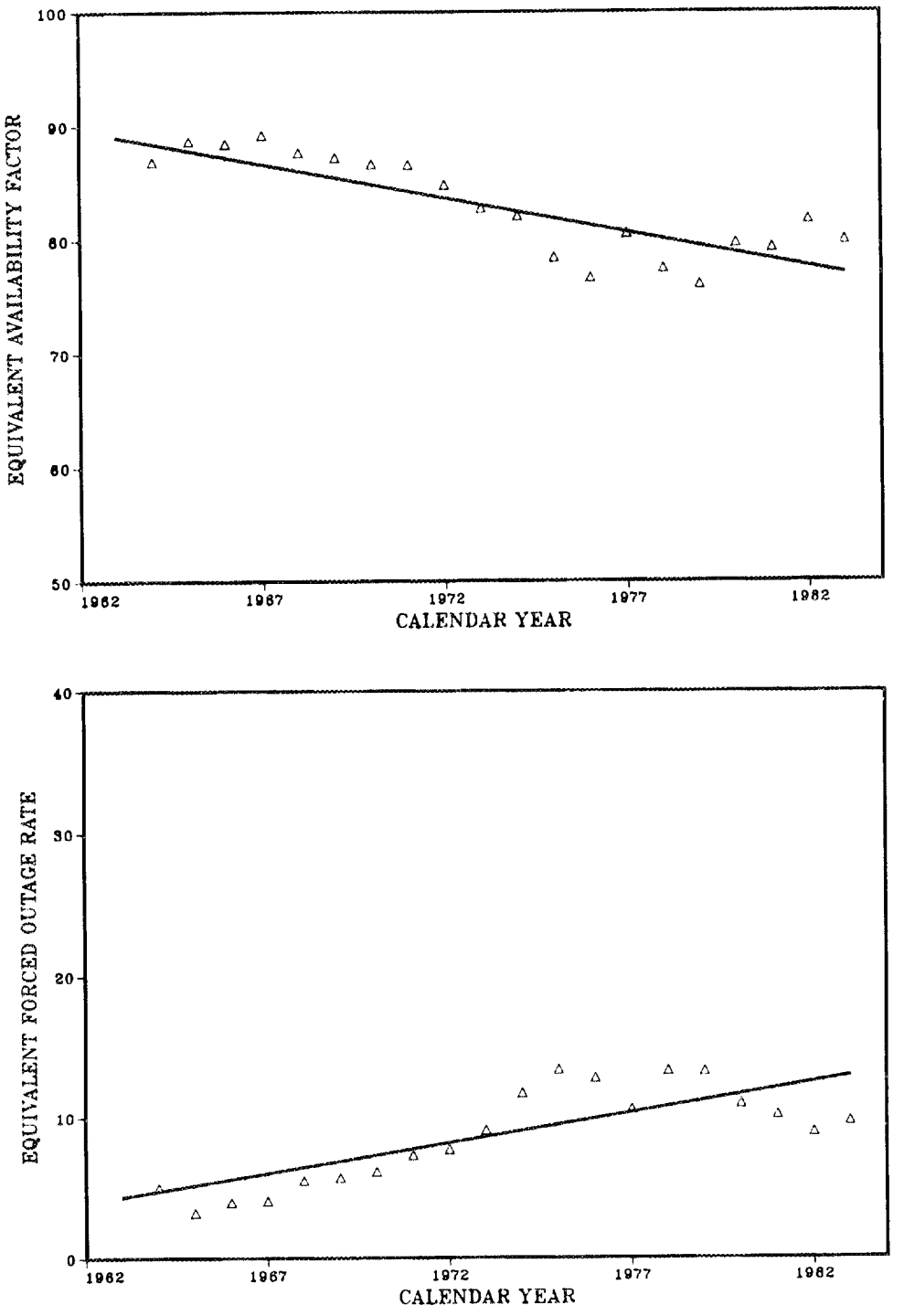

Fig. A.10. Average equivalent forced outage rate and equivalent availability factor as a function of calendar year of operation for the 200-299 MW(e) size range.

ORNL-DWG 85-5214 ETD

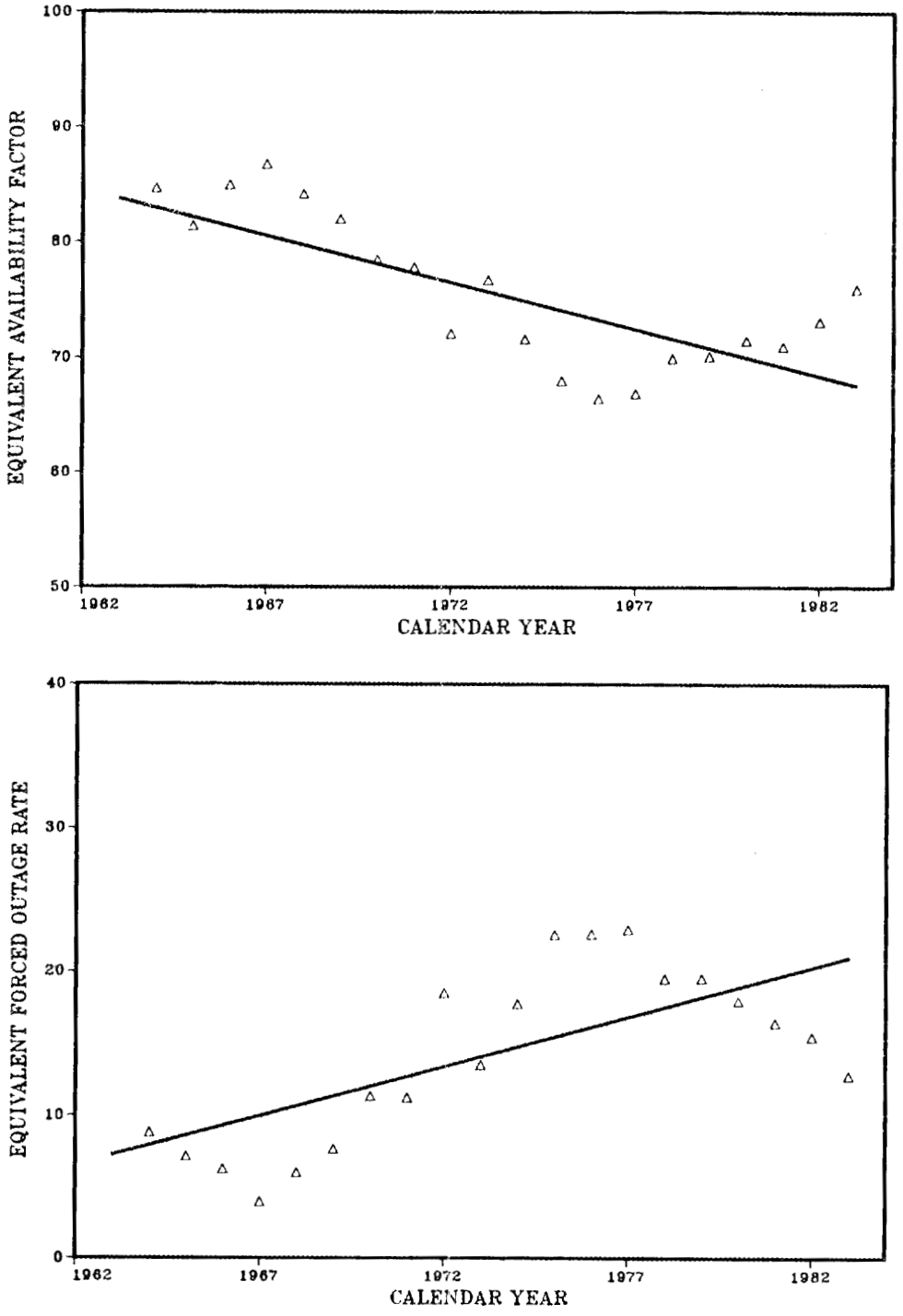

Fig. A.11. Average equivalent forced outage rate and equivalent availability factor as a function of calendar year of operation for the 300-399 MW(e) size range.

ORNL-DWG 85-5215 ETD

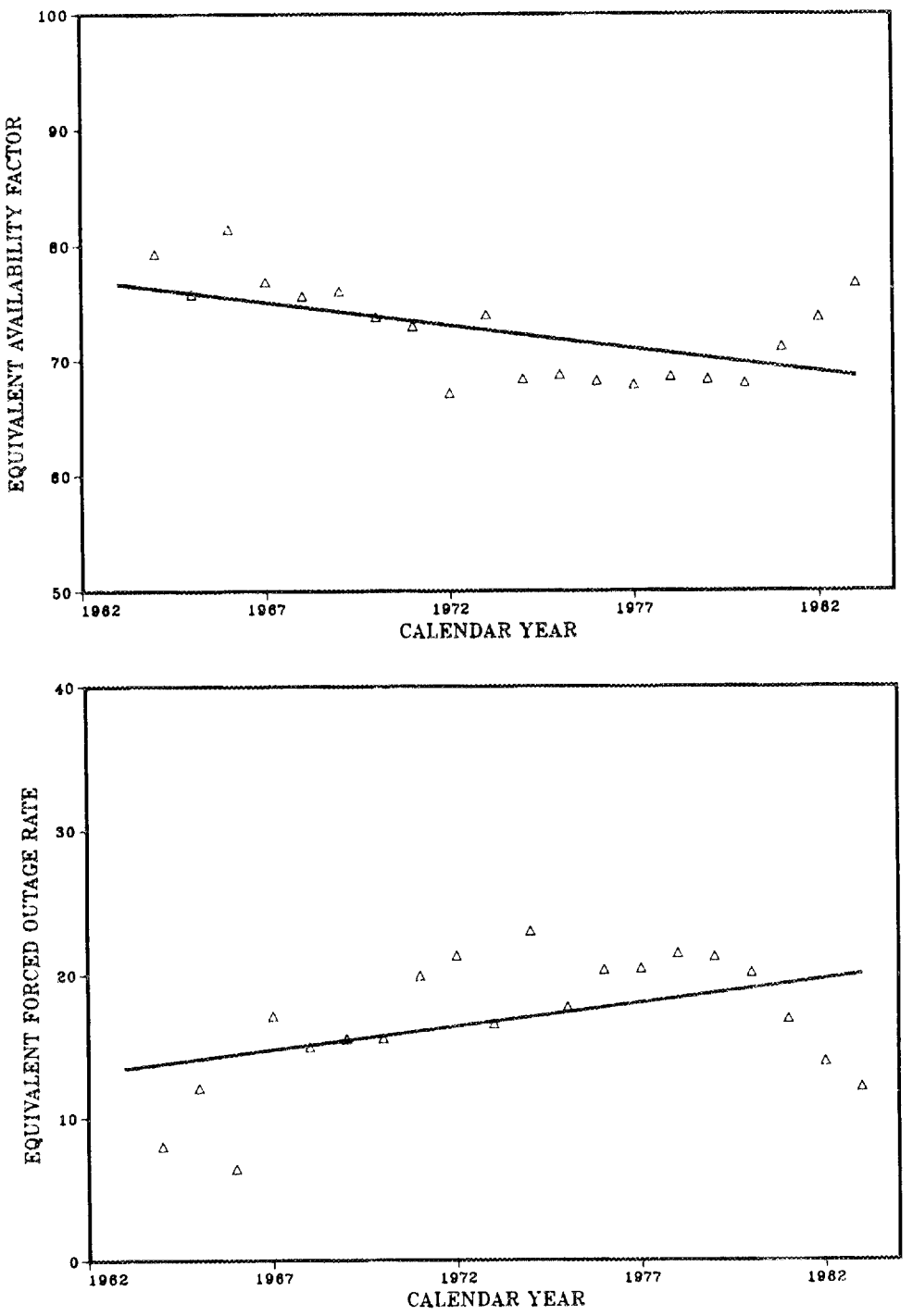

Fig. A.12. Average equivalent forced outage rate and equivalent availability factor as a function of calendar year of operation for the 400-599 MW(e) size range.

ORNL-DWG 85-5216 ETD

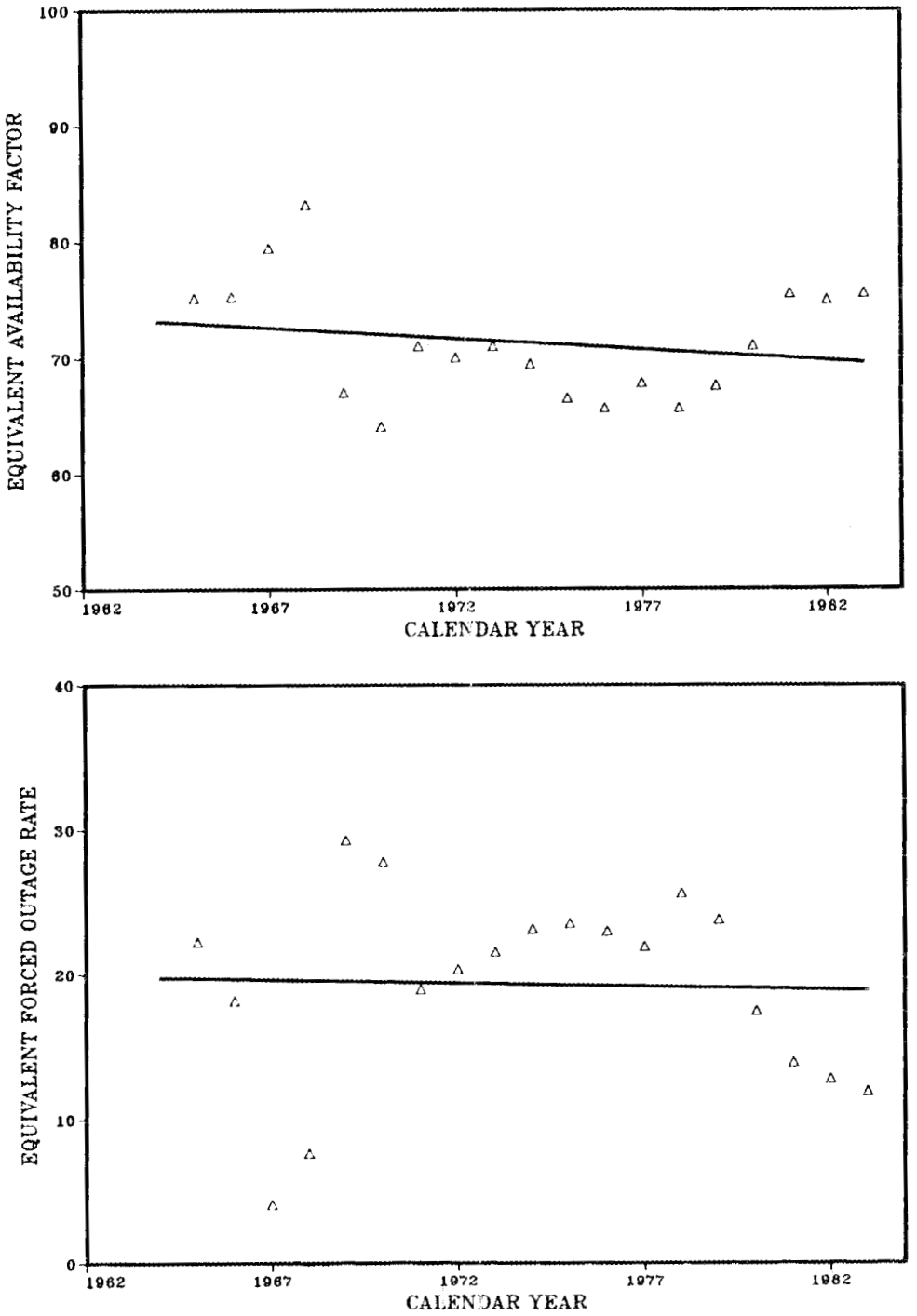

Fig. A.13. Average equivalent forced outage rate and equivalent availability factor as a function of calendar year of operation for the 600-799 MW(e) size range.

ORNL-DWG 85-5217 ETD

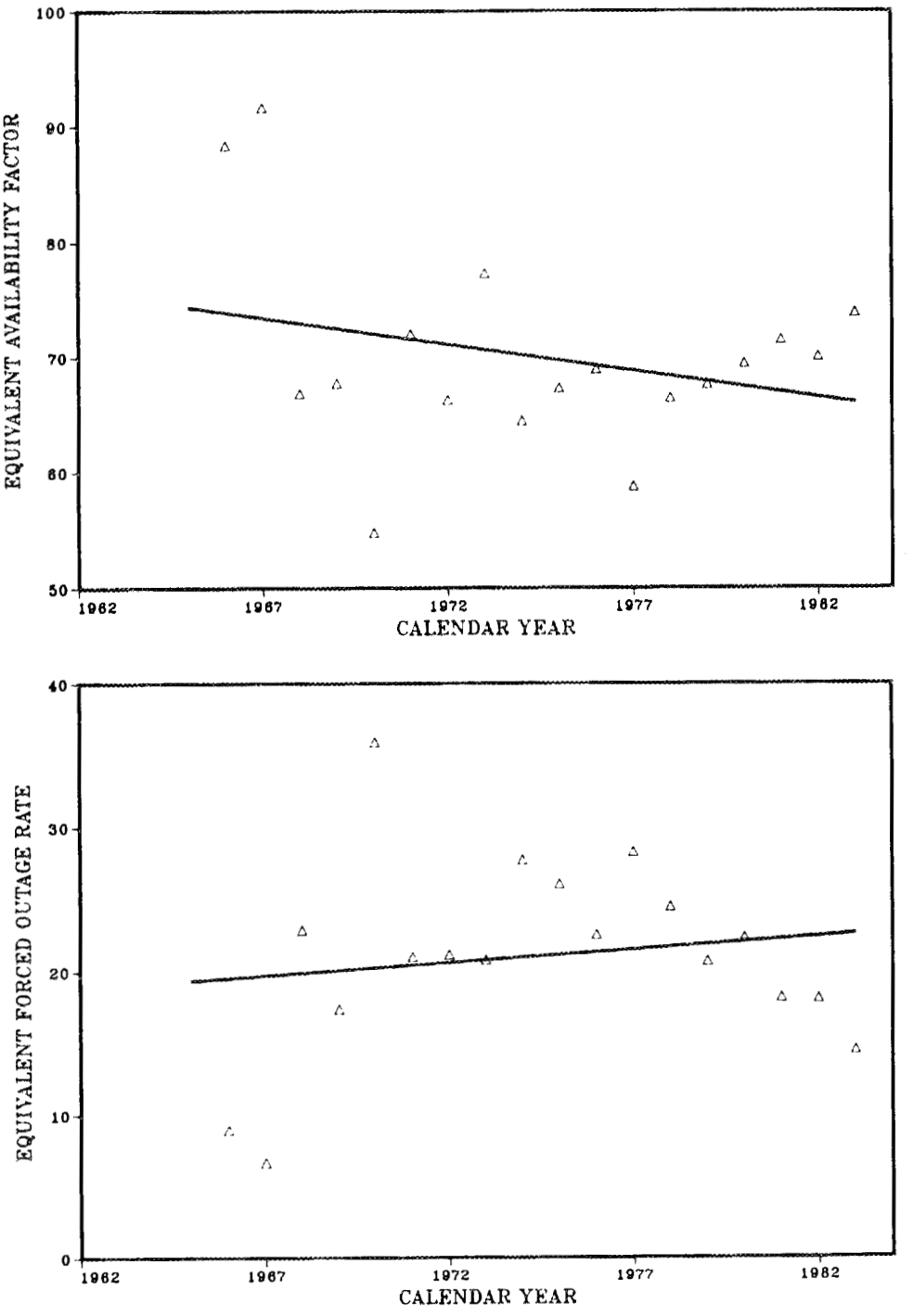

Fig. A.14. Average equivalent forced outage rate and equivalent availability factor as a function of calendar year of operation for the > 800 MW(e) size range.

ORNL-DWG 85-5279 ETD

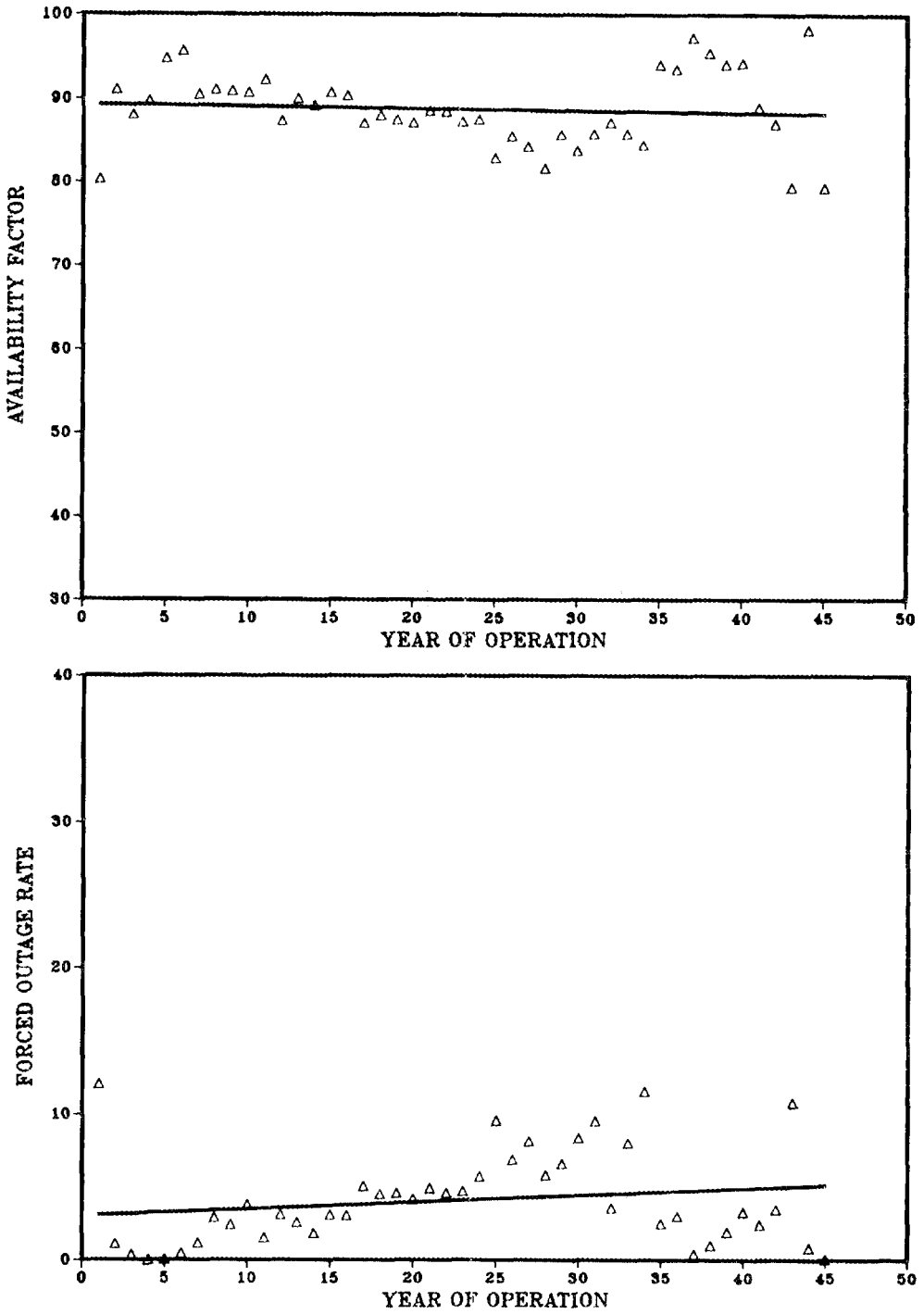

Fig. A.15. Average forced outage rate and availability factor as a function of year of operation for the 1-99 MW(e) size range.

ORNL-DWG 85-5280 ETD

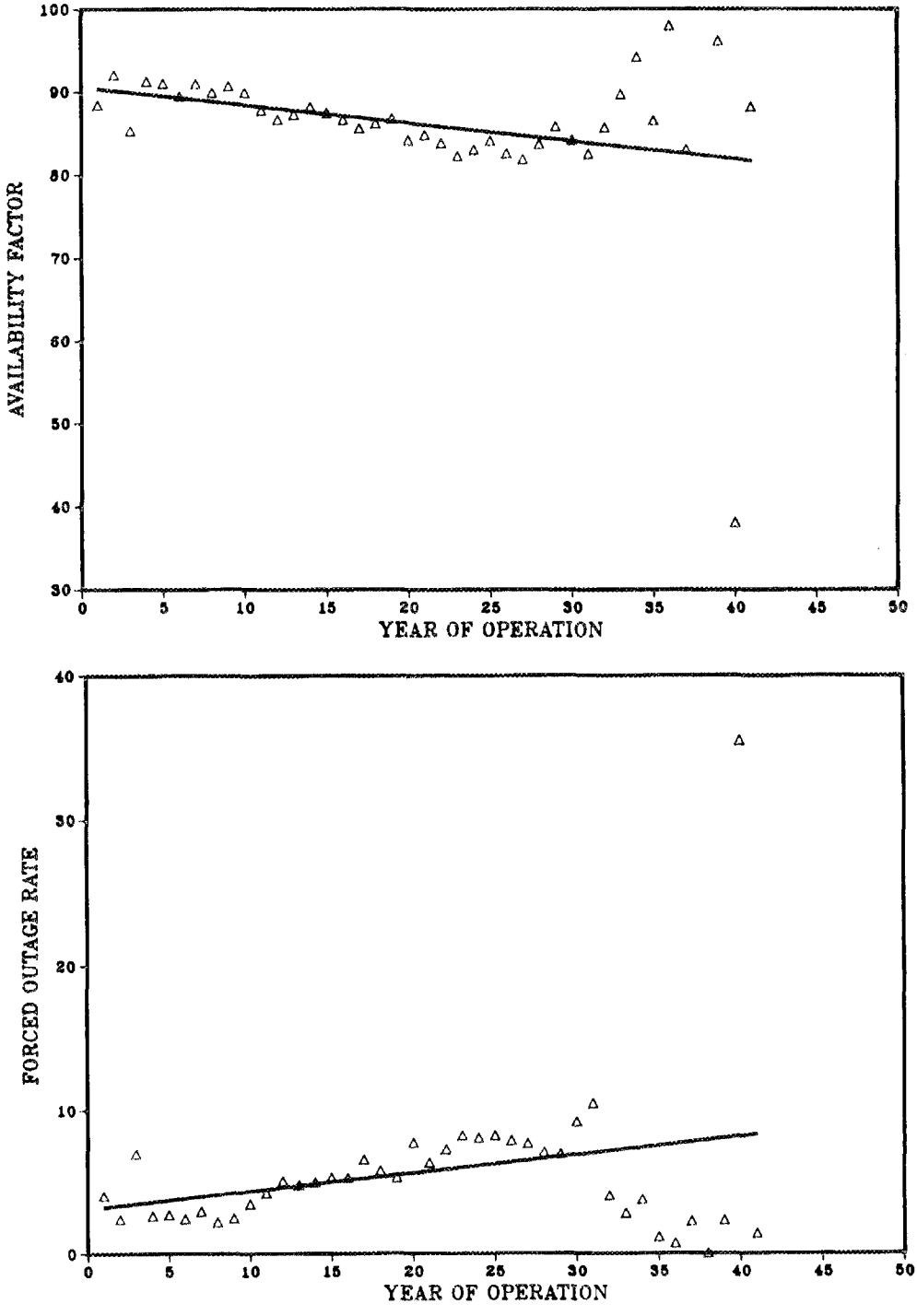

Fig. A.16. Average forced outage rate and availability factor as a function of year of operation for the 100-199 MW(e) size range.

ORNL--DWG 85--5281 ETD

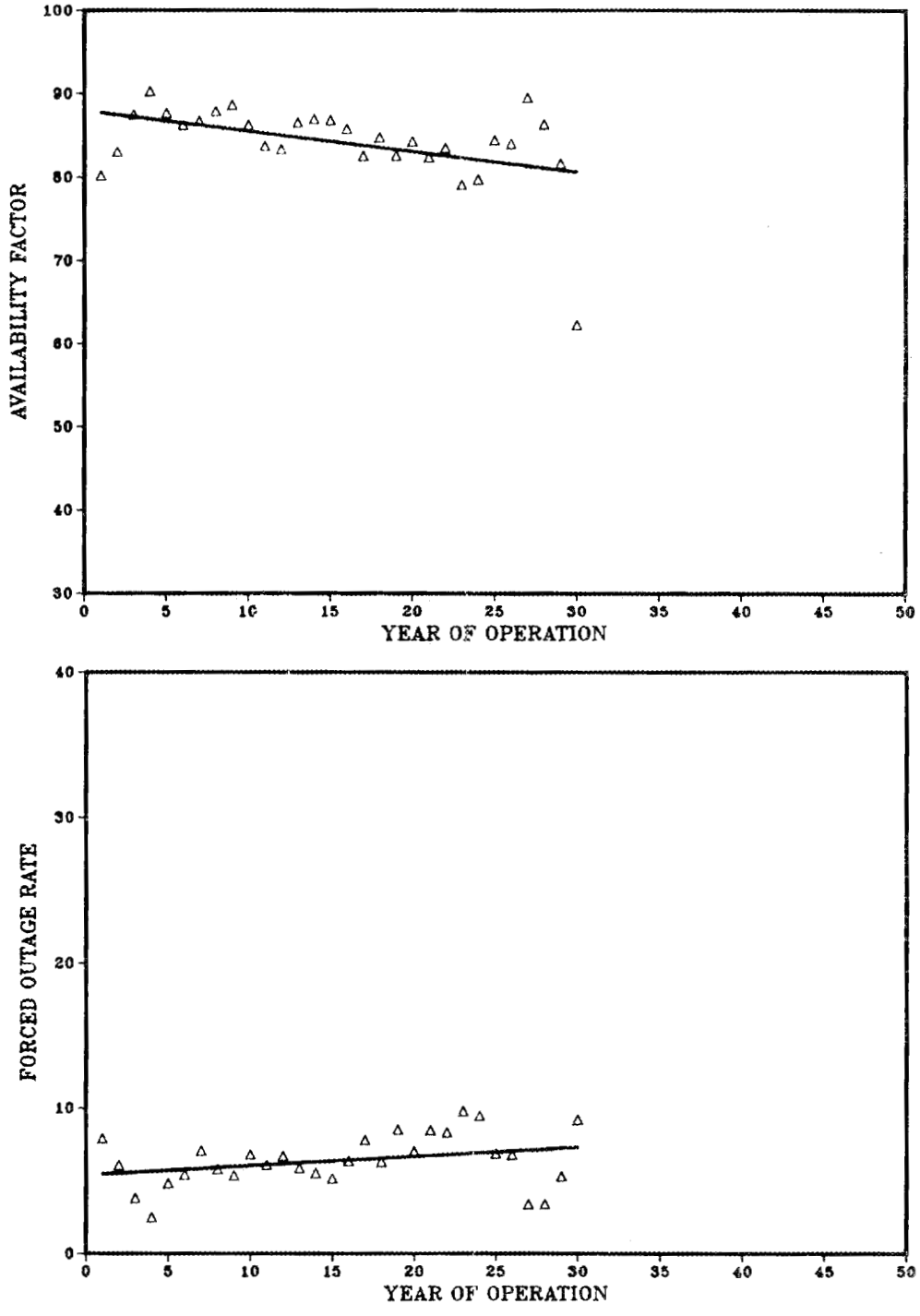

Fig. A.17. Average forced outage rate and availability factor as a function of year of operation for the 200-299 MW(e) size range.

ORNL–DWG 85–5282 ETD

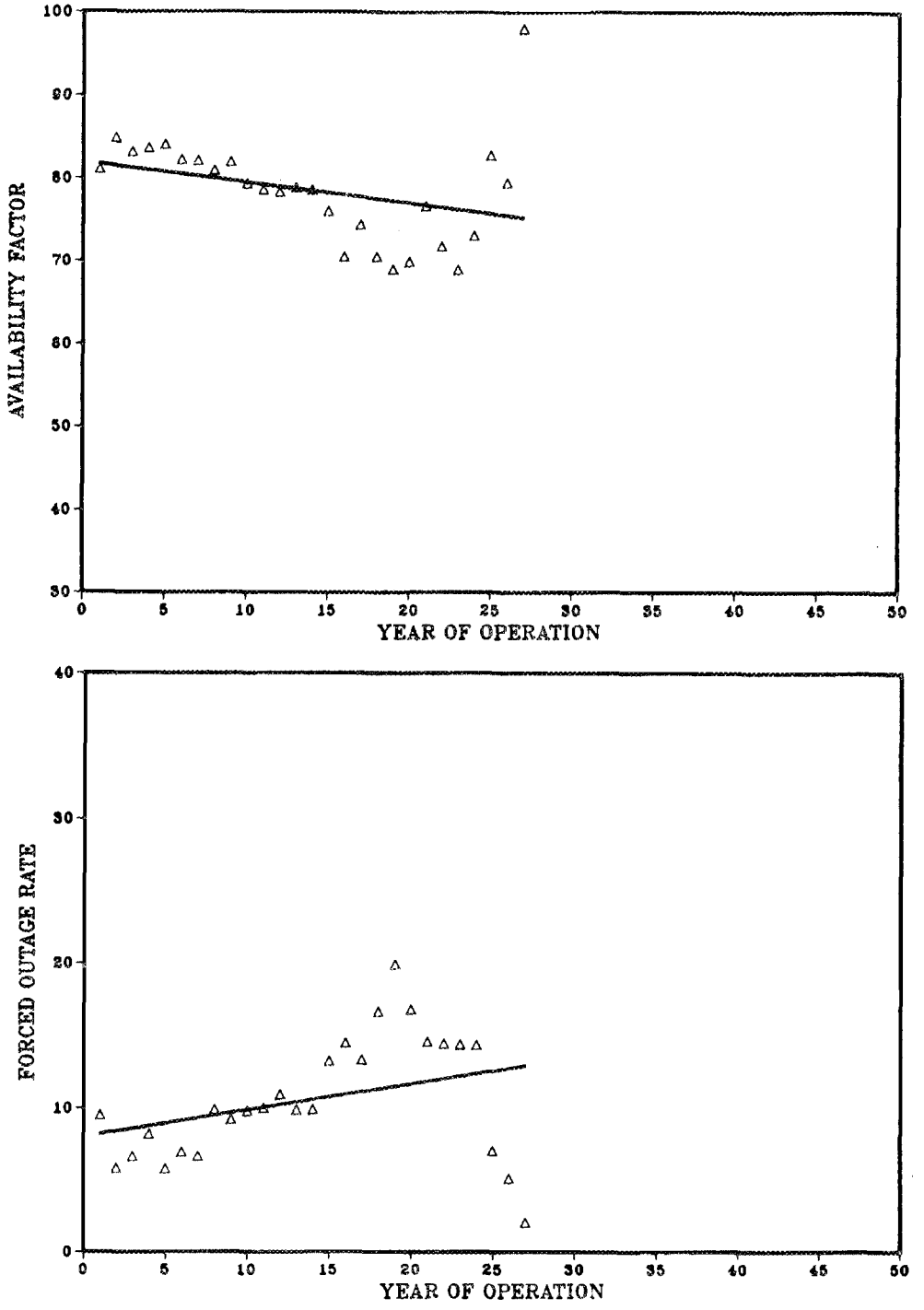

Fig. A.18. Average forced outage rate and availability factor as a function of year of operation for the 300-399 MW(e) size range.

ORNL-DWG 85-5283 ETD

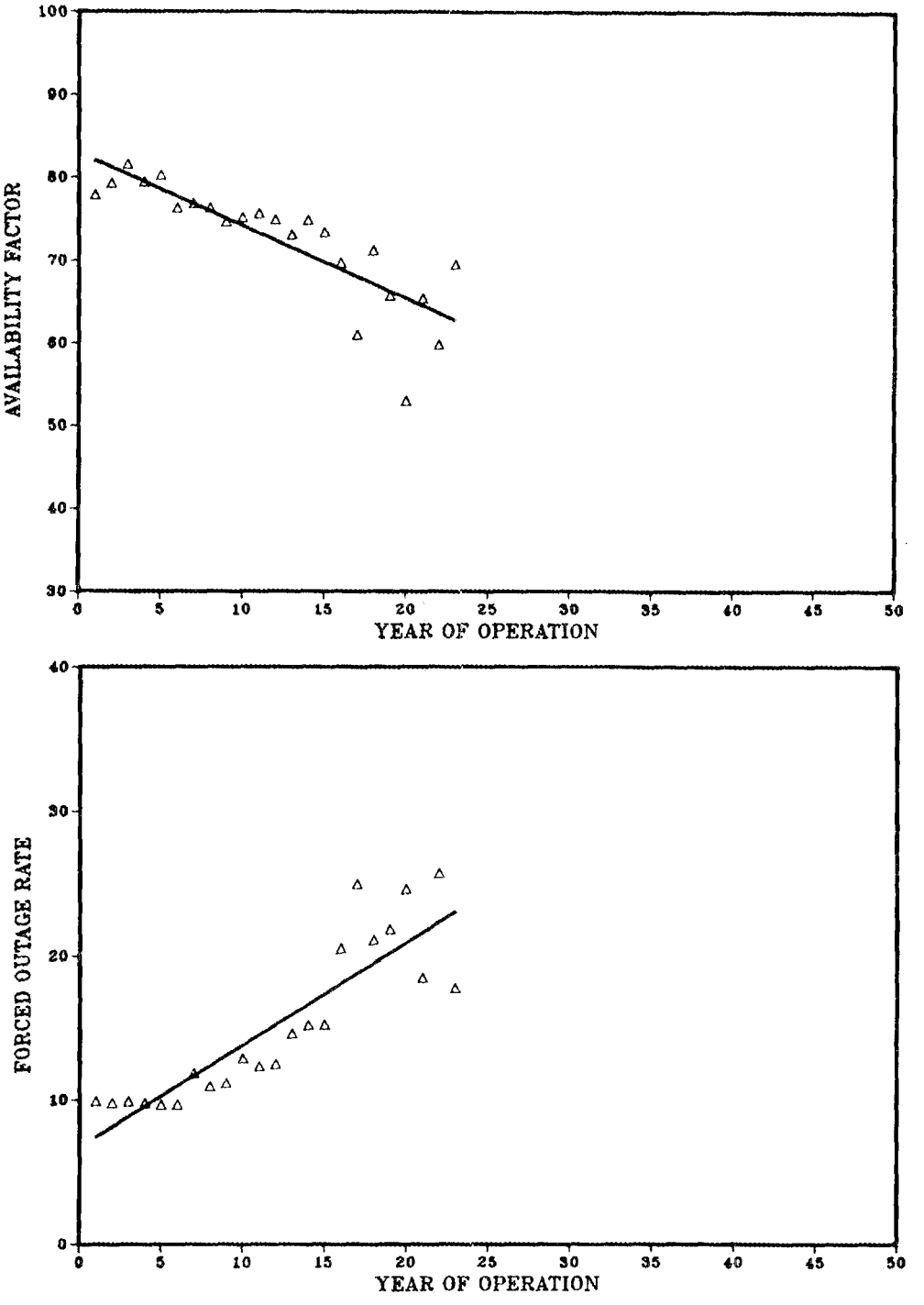

Fig. A.19. Average forced outage rate and availability factor as a function of year of operation for the 400-599 MW(e) size range.

ORNL-DWG 85-5284 ETD

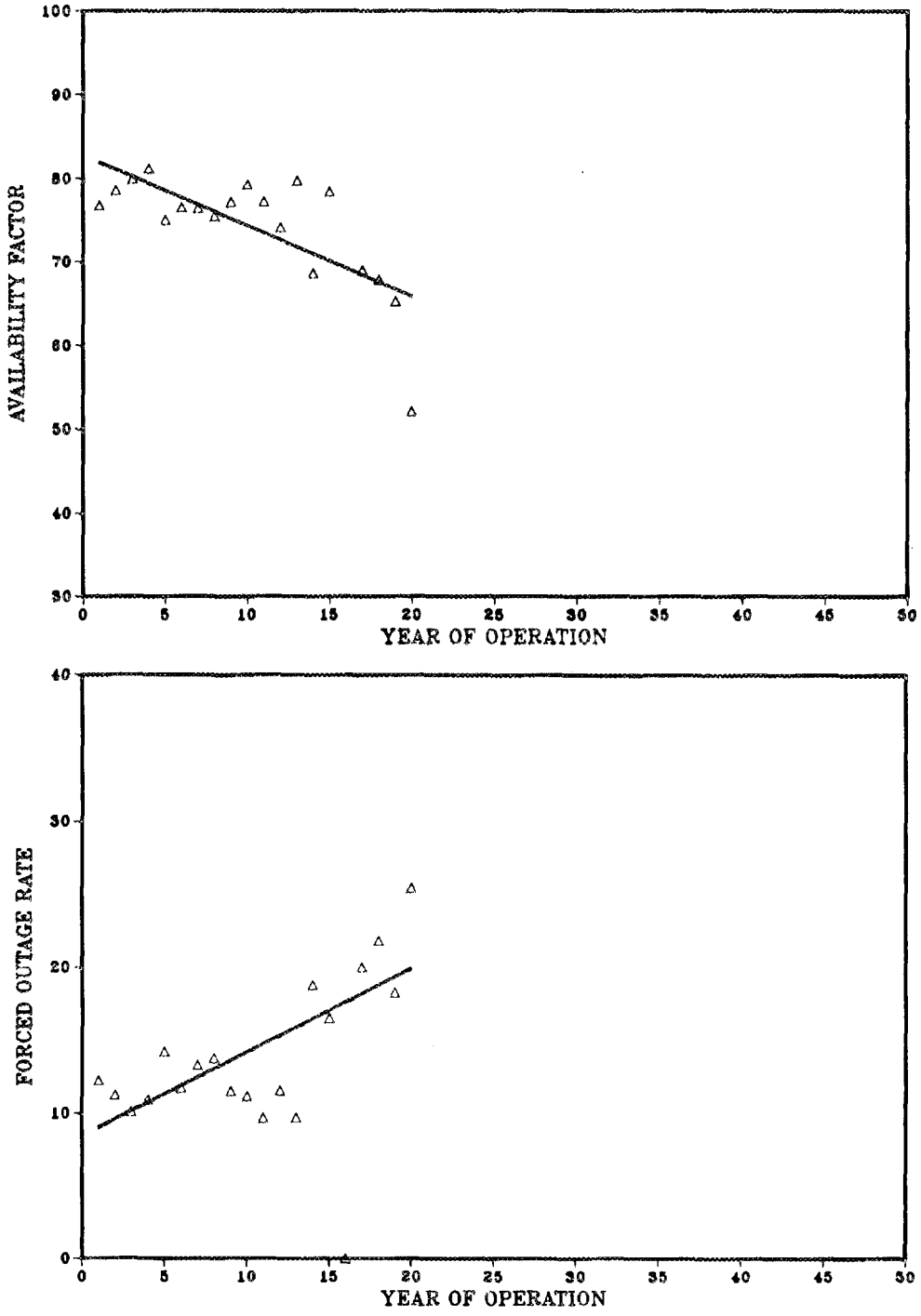

Fig. A.20. Average forced outage rate and availability factor as a function of year of operation for the 600-799 MW(e) size range.

ORNL-DWG 85-5285 ETD

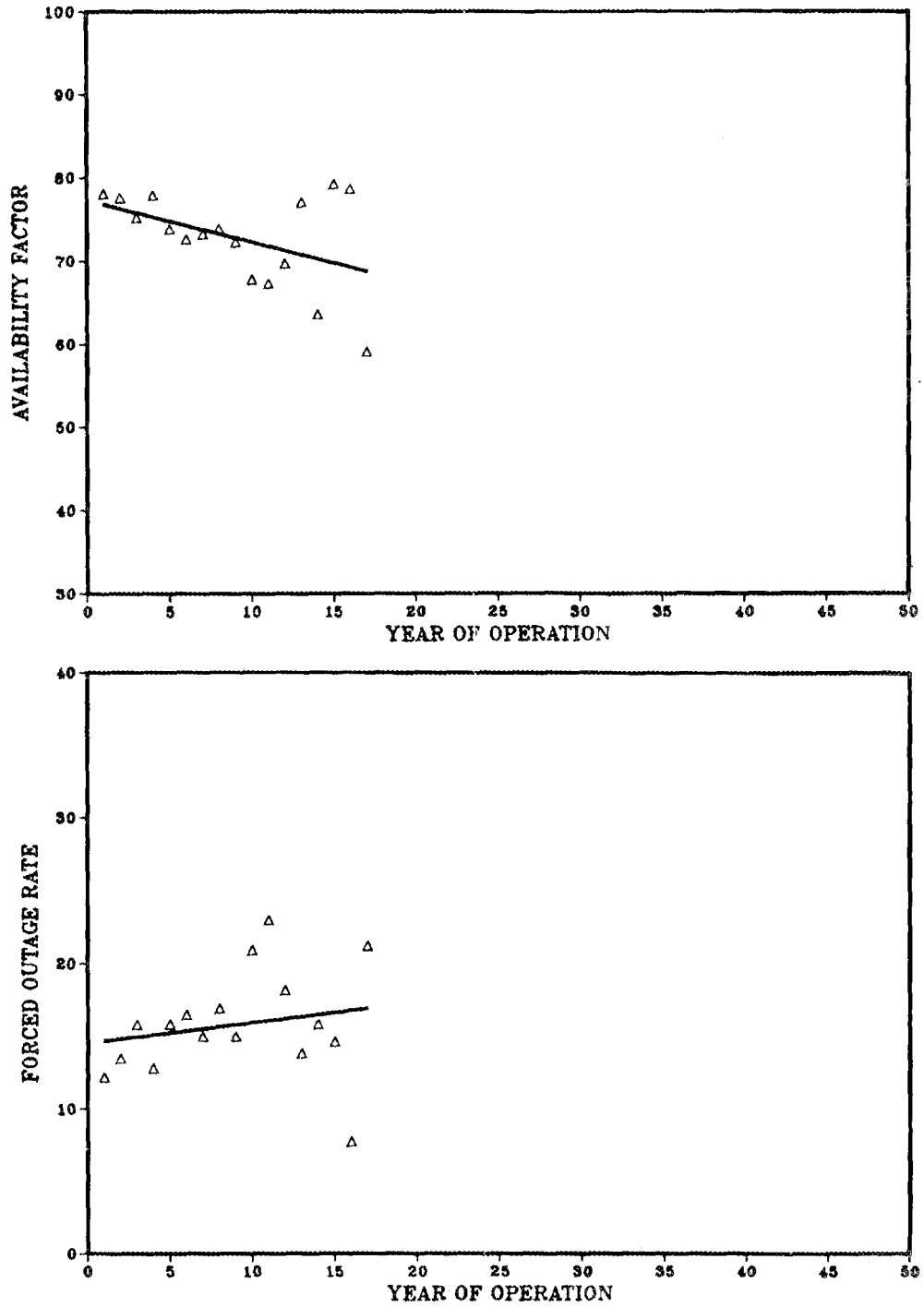

Fig. A.21. Average forced outage rate and availability factor as a function of year of operation for the > 800 MW(e) size range.

ORNL-DWG 85-5272 ETD

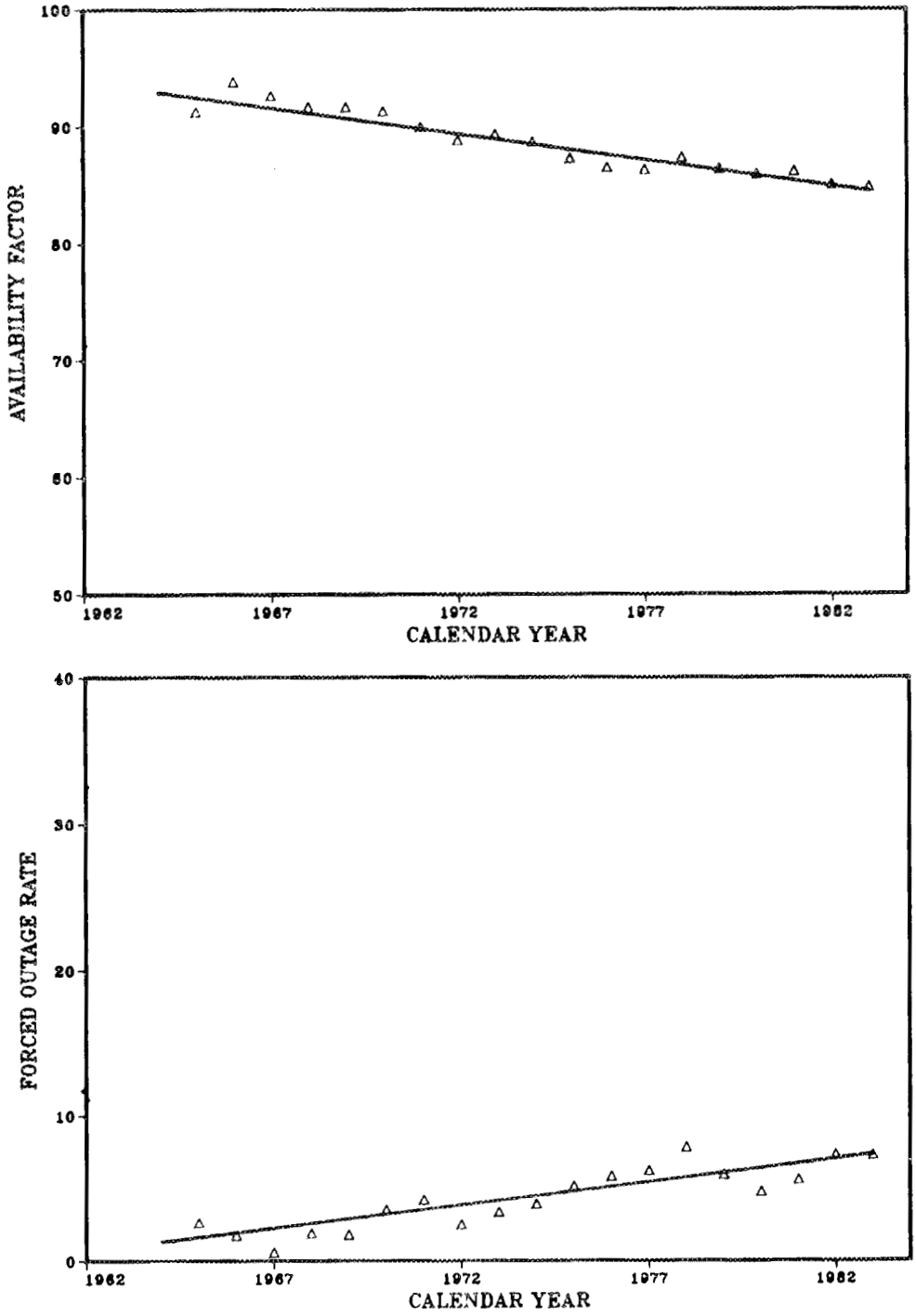

Fig. A.22. Average forced outage rate and availability factor as a function of calendar year of operation for the 1-99 MW(e) size range.

ORNL-DWG 85-5273 ETD

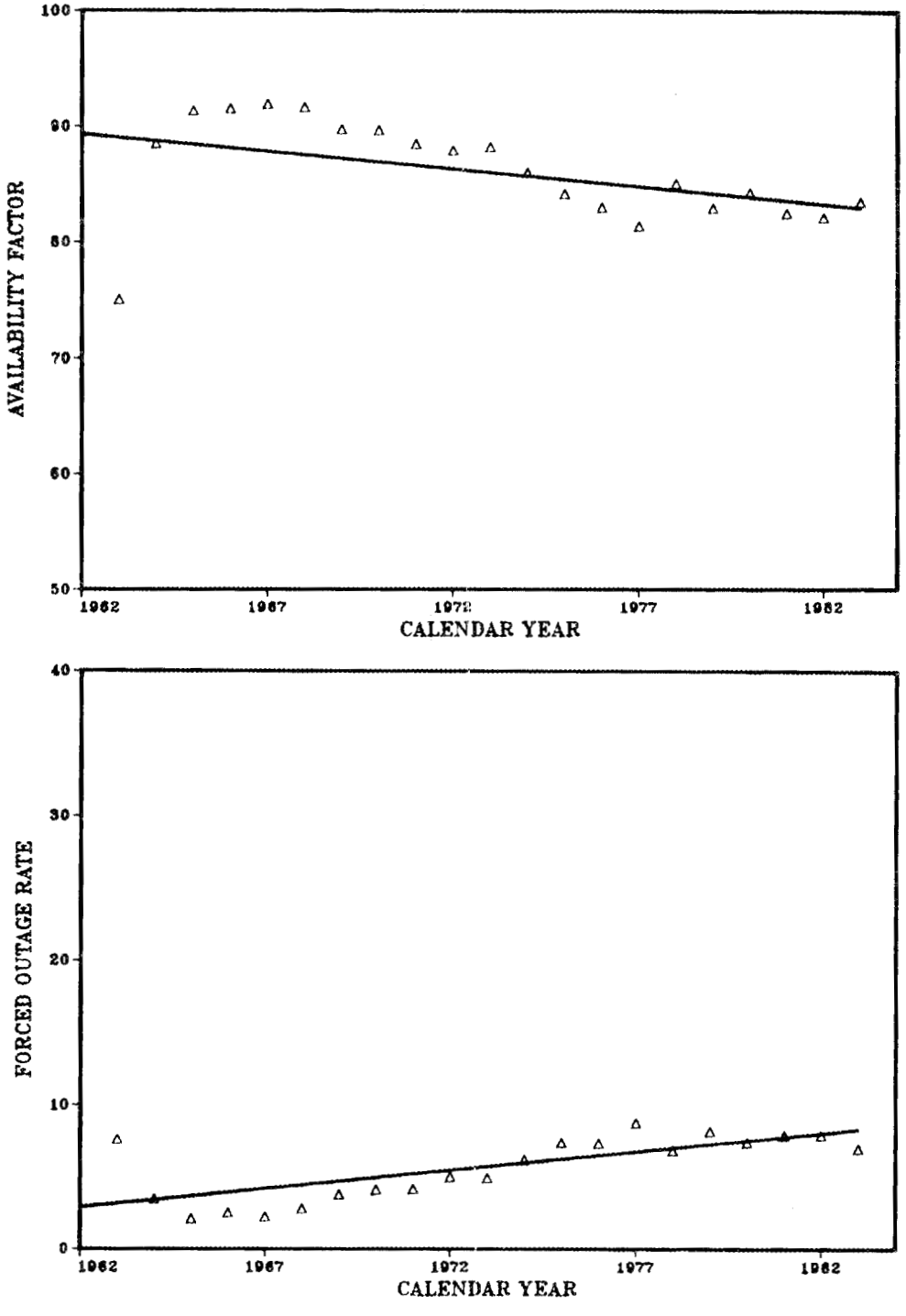

Fig. A.23. Average forced outage rate and availability factor as a function of calendar year of operation for the 100-199 MW(e) size range.

ORNL-DWG 85-5274 ETD

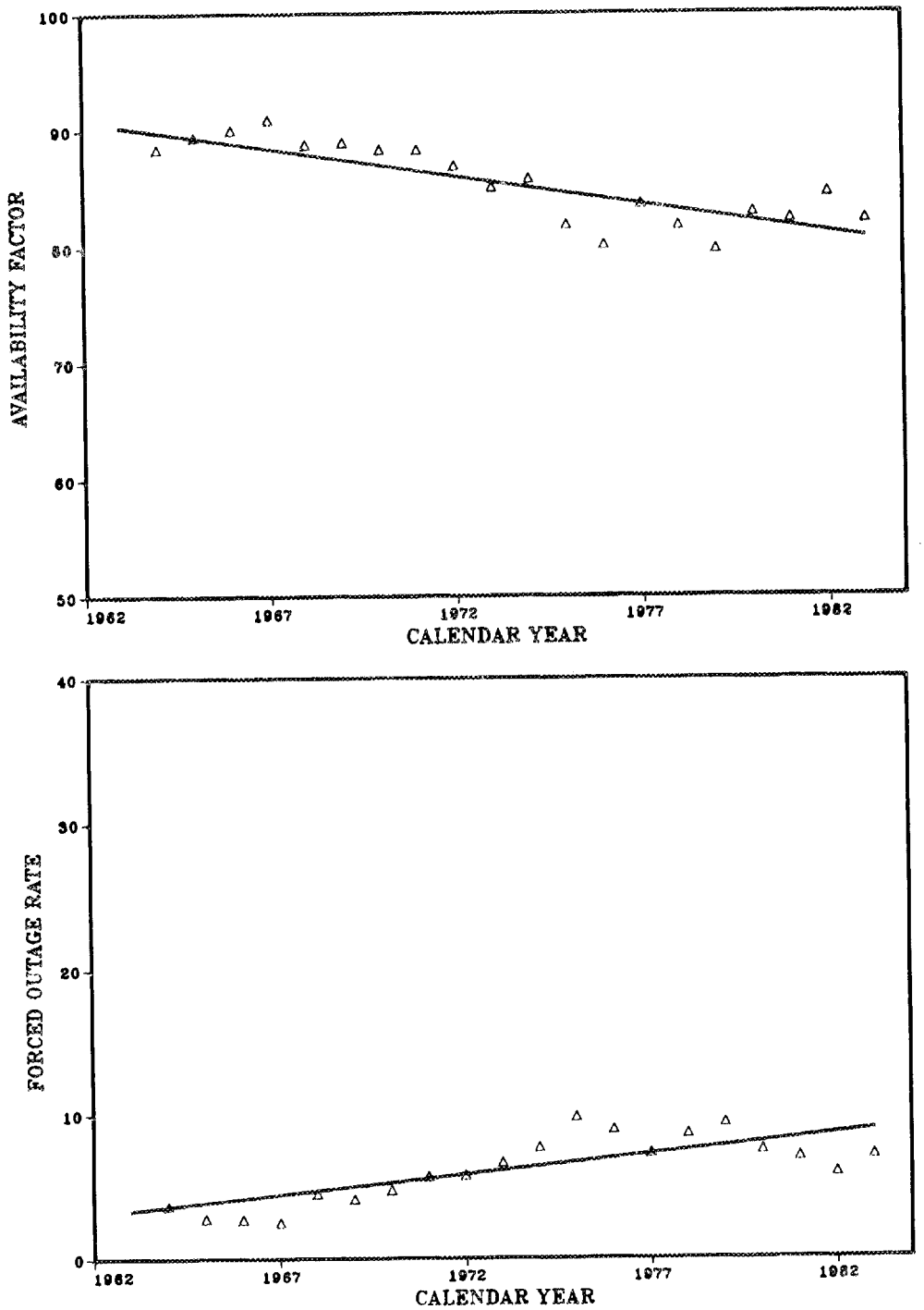

Fig. A.24. Average forced outage rate and availability factor as a function of calendar year of operation for the 200-299 MW(e) size range.

ORNL-DWG 85-5275 ETD

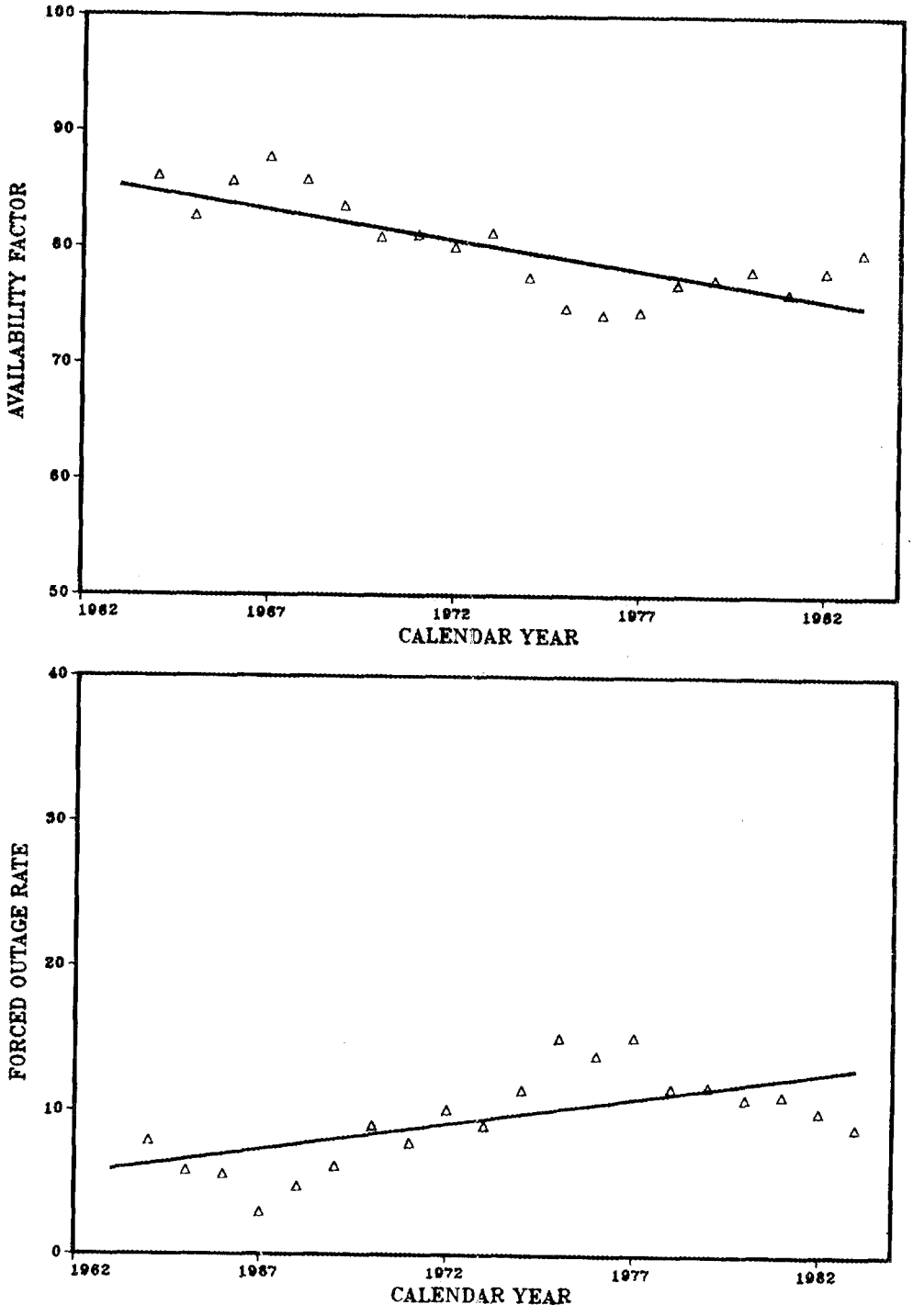

Fig. A.25. Average forced outage rate and availability factor as a function of calendar year of operation for the 300-399 MW(e) size range.

ORNL-DWG 85-5276 ETD

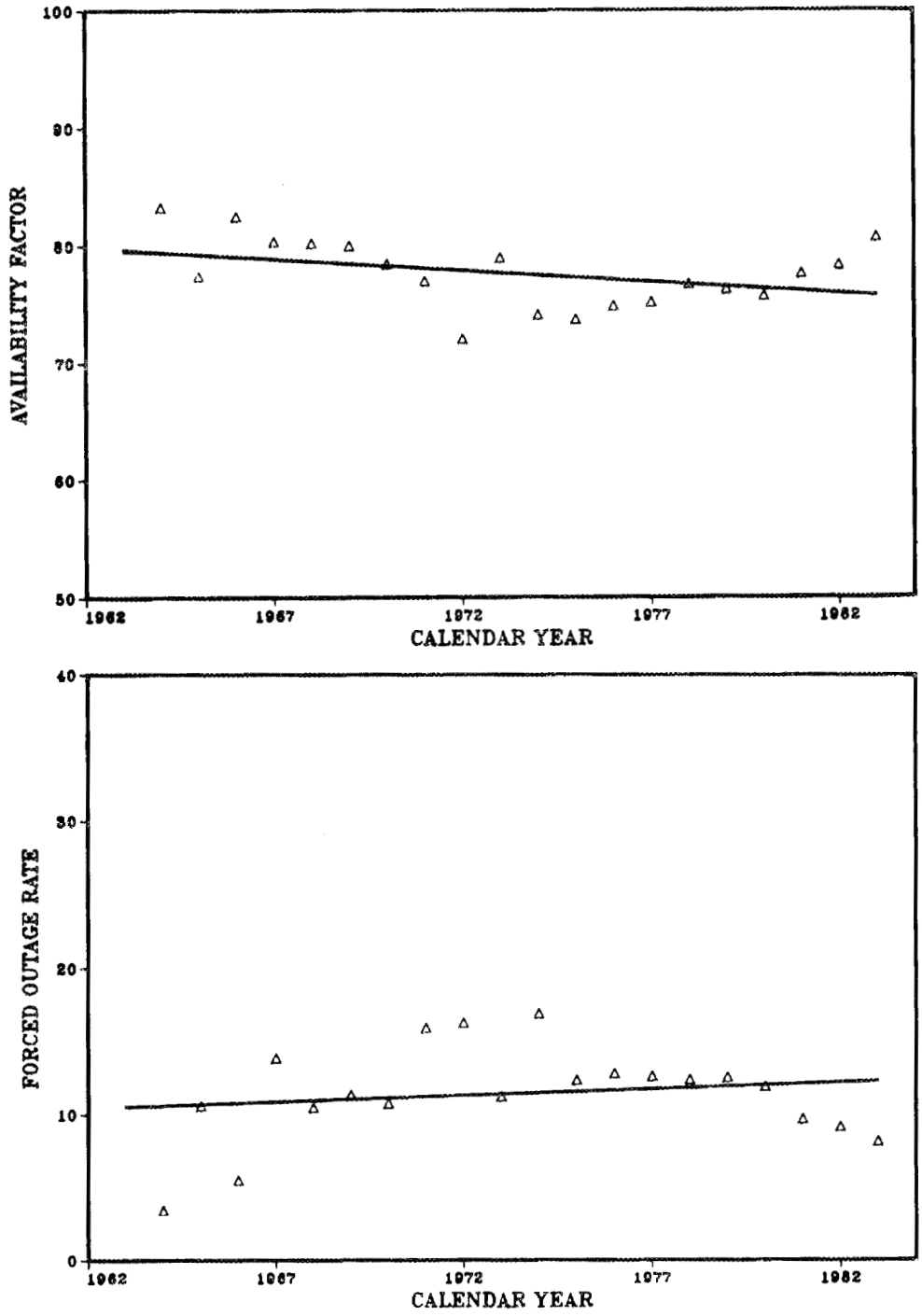

Fig. A.26. Average forced outage rate and availability factor as a function of calendar year of operation for the 400-599 MW(e) size range.

ORNL-DWG 85-5277 ETD

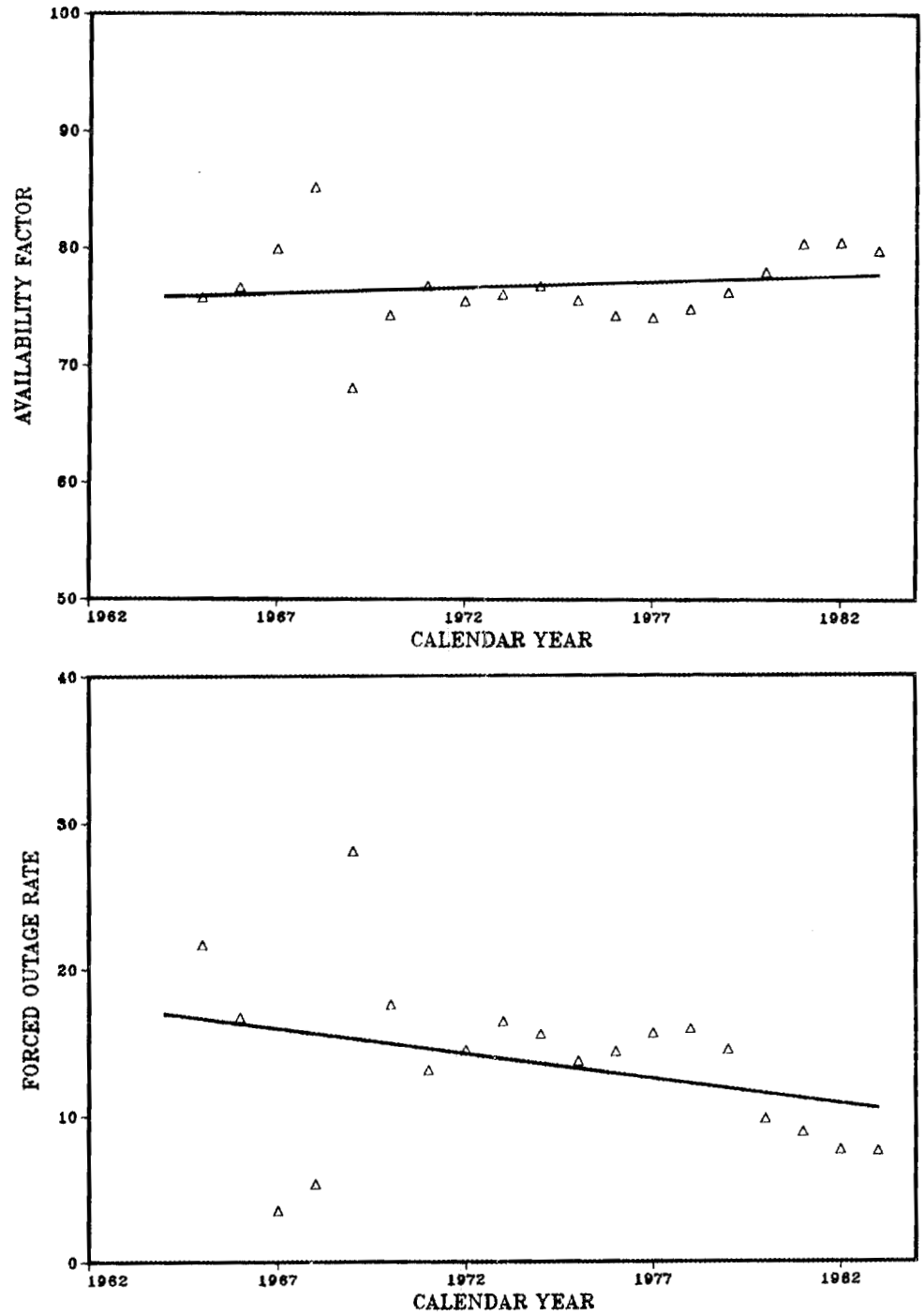

Fig. A.27. Average forced outage rate and availability factor as a function of calendar year of operation for the 600-799 MW(e) size range.

ORNL-DWG 85-5278 ETD

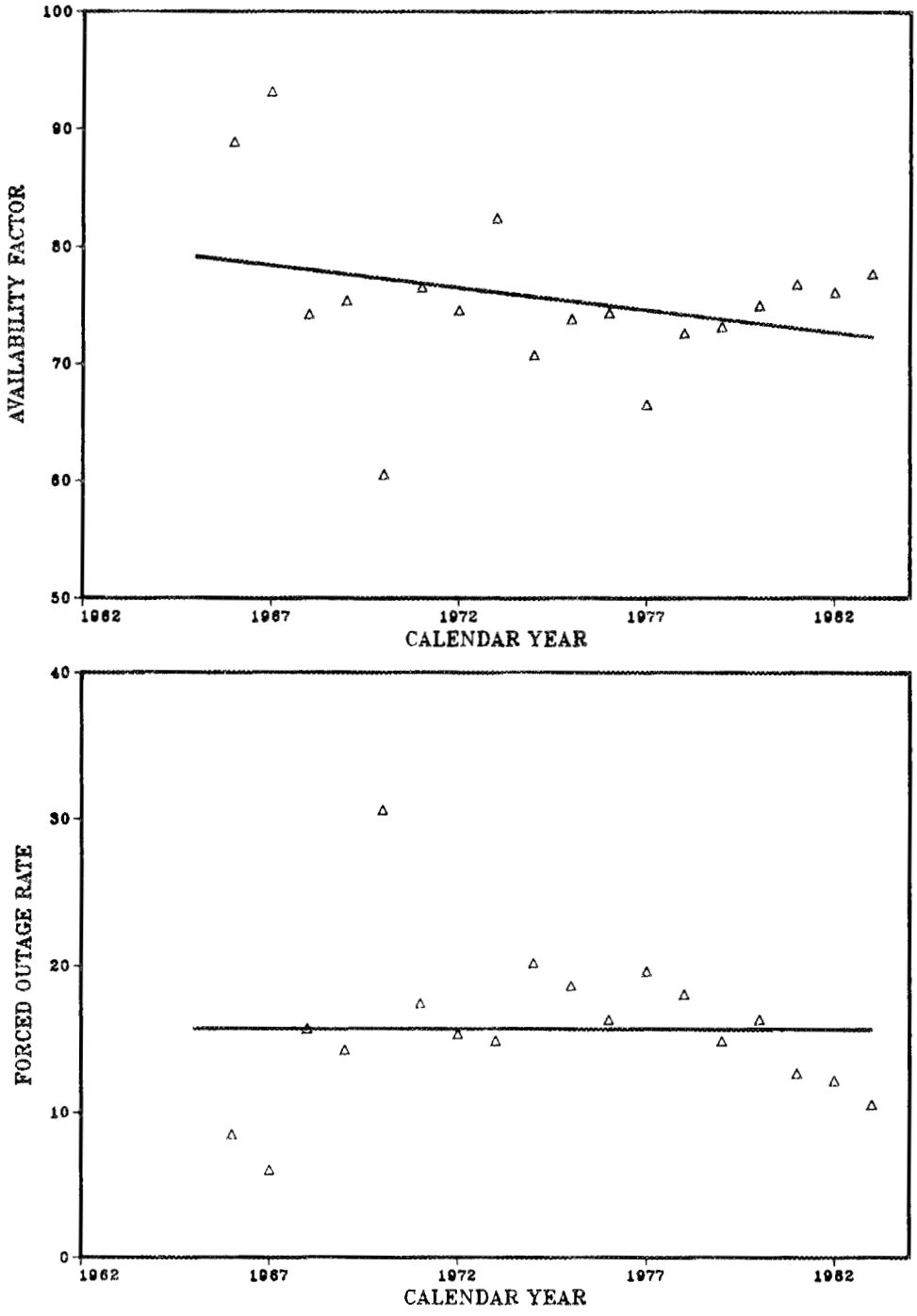

Fig. A.28. Average forced outage rate and availability factor as a function of calendar year of operation for the 800 MW(e) size range.

Internal Distribution

1. H. W. Bertini
2. D. J. Bjornstad
3-7. H. I. Bowers
8. W. G. Craddick
9. J. G. Delene
10. L. C. Fuller
11. C. R. Hudson II
12-16. M. J. Taylor
17. H. E. Trammell
18. K. A. Williams
19. ORNL Patent Office
20. Central Research Library
21. Document Reference Section
22-23. Laboratory Records Department
24. Laboratory Records (RC)

External Distribution

25-34. A. H. Fuldner, MS-2F-021, Energy Information Administration, Department of Energy, Washington, D.C. 20585
35. J. Jones, MS-2F-021, Energy Information Administration, Department of Energy, Washington, D.C. 20585
36. Office of Assistant Manager for Energy Research and Development, Department of Energy, ORO, Oak Ridge, TN 37831
37-63. DOE Technical Information Center, P.O. Box 62, Oak Ridge, TN 37831