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GUIDE FOR PRIORITIZING POWER PLANT
PRODUCTIVITY IMPROVEMENT PROJECTS

HANDBOOK OF AVAILABILITY IMPROVEMENT METHODOLOGY

September 15, 1981

Prepared by

TRIDENT ENGINEERING ASSOCIATES, INC.
448 Maryland Avenue
Annapolis, Maryland 21401

under Subcontract Number 7435 for

OAK RIDGE NATIONAL LABORATORY
Oak Ridge, Tennessee 37830

Operated by

UNION CARBIDE CORPORATION
for the
DEPARTMENT OF ENERGY
(Contract No. W-7405-eng-26)

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PREFACE

The recent energy crisis and the continued escalation of fossil-fuel cost, combined with diminishing fuel supplies, have highlighted the urgency for improving power plant productivity. Increased cost-effective plant productivity has a three-fold economic effect for a utility:

1. Reduction or elimination of the need to construct new units;
2. Reduction in power replacement usage from less efficient and/or high fuel cost units; and
3. Reduced need to purchase power at increased cost from other utilities.

With today's uncertainties in available plant sites, high capital cost, high interest rates for new construction, licensing delays, and extended construction schedules, any plant improvements that reduce the need for constructing additional generating capacity have a substantial economic benefit. Considering the size of most U. S. electric utilities, even a small improvement in the productivity of each generating station results in a sizeable increase in the total system yearly generating capacity. Such a gain in production may result in the deferment of new plant construction.

Performance improvements in low fuel cost units reduce the need to operate less efficient plants or plants that burn high cost fuel. In addition to prolonging the usable life of some of the older units by reducing their operating schedules, the direct saving to a utility in fuel replacement cost is sizeable. The replacement power cost for a modern base-load unit is often cited as approaching \$1 million per day. Any improvement project that results in increased operating performance of these units can usually be justified as good economics.

To improve specific plant systems and hardware performance, it is necessary to know accurately the past performance for all components which contributed to unavailability. This requires an accurate and detailed data base and an engineering analysis to predict future performance of improved designs. Areas where improvements are necessary can often be identified from

past performance histories and/or discussions with responsible plant operations and maintenance personnel. But simply identifying problem areas is not enough to convince utility management that large expenditures of money are warranted to purchase new equipment or add additional plant personnel. Only with quantitative analysis that develops such classical reliability parameters as meantime-to-failure and meantime-to-repair can the reliability engineer begin to accurately rank the contribution of various systems on plant performance. Combining this ranking with cost estimates for improvement projects, the engineer can identify those areas which have the greatest potential cost impact on future plant operation. Based on the costs associated with implementing improvement projects and the projected return on investment resulting from improved plant operation, utility management can determine the economic merits of each project. The productivity improvement projects must be weighed, in turn, against other projects available to the corporation to increase operating efficiency. Power plant improvement projects must be carefully evaluated to assure that they are cost-effective within the context of all possible investment opportunities. Increased plant availability must not be sought as an end unto itself. It should only be sought where it is a most economic means of reducing overall costs.

During recent years, several federal and state agencies, individual utilities, utility groups, and various consultants have developed methods for identifying the key problems that cause reduced plant productivity. To some extent, nearly all the methods are similar in that historical plant data is used to calculate various reliability parameters which allow an estimate of plant operating availability. These calculations, combined with estimated costs of improvement projects, allow a benefit/cost analysis to determine the merits of specific projects.

Although generally similar, reliability methods do have some basic differences. These differences are most apparent in how and where equipment performance data is obtained. Some methods use actual plant equipment failure data gathered from plant maintenance and operating reports to predict future trends. Other methods rely on statistical methods, trending, or equipment manufacturers' predictions to construct a data base. In either case, accurate equipment failure data is probably the most important single parameter needed to perform power plant reliability/availability analyses.

The Availability Improvement Methodology (AIM) presented in this handbook describes a method for calculating the increase

in plant equivalent availability factor resulting from a proposed improvement project. AIM uses the recently developed IEEE definitions along with other reliability parameters for establishing unit availability and performance. Additionally, AIM calculations are based primarily on data being collected for the Generating Availability Data System (GADS) of the National Electric Reliability Council. Several utilities are presently collecting equipment outage data on the GADS Performance and Event Report Forms. This data, if properly developed, is sufficient for performing most of the AIM calculations. The more descriptive the GADS data, the more detailed the AIM calculations become, allowing for the analysis of a wider range of improvement projects.

Once collected and sorted, this data is used to construct an historical gross available generation (GAG) profile and to develop reliability parameters describing past plant operation. Based on assumptions concerning the effect of a specific improvement project to increase plant operation, a hypothetical gross available generation (GAG) profile is constructed, along with necessary reliability parameters, and compared to the historical one. The differences in the historical and hypothetical GAG profiles and reliability parameters show the resultant increase in plant equivalent availability factor that results from the improvement project under study. All definitions, data sheets, and equations needed to apply the methodology are presented in this handbook. In order to allow a utility engineer to fully understand the application of the methodology, several examples of the evaluation of various improvement projects are presented. In each case, the analysis consists of using plant data to assess future operation after the improvement project is implemented. Based on the result of one of the improvement projects, a benefit/cost analysis is performed to determine the financial merits of such a project.

In applying the AIM methodology, utility engineers should be mindful that replacement power costs are frequently greater for forced outages than for planned outages. Equivalent availability includes both. A cost-effective ranking of alternative plant improvement projects must discern between those projects which will reduce forced outages and those which might reduce planned outages.

AIM is not appropriate for assessing the reduction or elimination of the need to construct new units. For this objective, it is necessary to separate forced and maintenance outages in the computations because the forced outages will be several

times as effective per fraction of time in requiring additional reserves compared with planned maintenance outages. As is the case with any analytical procedure, engineering judgement must be exercised with respect to the results of purely mathematical calculations.

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1.0 INTRODUCTION, OVERVIEW, AND REQUIREMENTS

As part of its program to help improve electrical power plant productivity, the Department of Energy (DOE) has developed a methodology^[1] for evaluating productivity improvement projects. This handbook presents a simplified version of this methodology called the Availability Improvement Methodology (AIM), which provides a systematic approach for prioritizing plant improvement projects. Also included in this handbook is a description of data taking requirements necessary to support the AIM methodology, benefit/cost analysis, and root cause analysis for tracing persistent power plant problems.

In applying the AIM methodology, utility engineers should be mindful that replacement power costs are frequently greater for forced outages than for planned outages. Equivalent availability includes both. A cost-effective ranking of alternative plant improvement projects must discern between those projects which will reduce forced outages and those which might reduce planned outages. As is the case with any analytical procedure, engineering judgement must be exercised with respect to results of purely mathematical calculations.

1.1 OVERVIEW OF THE AIM METHODOLOGY

To analyze power plant productivity, several measures of performance should be examined. However, a single index widely used for base-load plants is the equivalent availability factor (EAF). The EAF is essentially equivalent to the percentage of time during which a unit was available for operation at its full capability. The EAF takes into account those times during which the unit was available at less than full rating due to all outages, including forced-partial and scheduled-partial outages.

The methodology described in this handbook uses the change in equivalent availability factor (ΔEAF) as the performance parameter to assess increases in plant productivity resulting from corrective actions. The change in equivalent availability factor measures the additional megawatt hours of available generation divided by the unit's maximum possible generation in a given time period. The method calculates the change in the unit equivalent availability factor resulting from a planned improvement project and considers the impact of the new improvement project on two major factors:

- ° Unit equivalent unavailability factor due to component events; and

- Unit equivalent unavailability factor due to external/economic events.

A component event is defined to occur when a component undergoes any of the following:

- Loss of function capability (i.e., mechanical breakdown, rotational or vibrational problem, operation out of spec, etc.);
- Preventive and routine maintenance;
- Inspection, surveillance, or testing;
- Modification.

An event can result in a plant outage, derate, or even non-curtailment of service. The equivalent availability factor considers both maintenance and forced outages. Since the power replacement cost of these outages is apt to be different, care must be taken in performing the analysis of the benefits associated with improvement projects that affect various types of outages.

An external/economic event is defined as an event which potentially limits the plant output and which is not component-related, such as a unit derated to meet environmental emission standards or a unit off-line due to earthquakes, floods, or labor problems.

The methodology considers the effect of concurrent component and external/economic events when evaluating an improvement project. Examples of concurrent events include a pulverizer mill at a coal plant out for maintenance while the unit is derated to meet environmental emission standards, or a condensate pump and a boiler circulation pump both simultaneously out for repair.

The methodology determines the increase in plant equivalent availability factor resulting from improvement projects by use of the equation:

$$\Delta EAF = -\Delta EUF_F - \Delta EUF_{EE} \quad (1)$$

where

ΔEAF = Change in unit equivalent availability factor resulting from a given improvement project

ΔEUF_F = Change in unit's equivalent unavailability factor due to the improvement project's impact on the unit's component events

ΔEUF_{EE} = Change in unit's equivalent unavailability factor due to the improvement project's impact on the unit's external/economic events

Physically, ΔEAF is the additional megawatt hours of energy the unit will generate divided by the megawatt hours the unit could generate in a given time period operating at its gross maximum capacity after implementing an improvement project. A ΔEAF equal to .274%* results in a unit producing one more full power day of energy per year of operation.

The methodology requires the collection of detailed plant data which can be developed from properly completed GADS Performance and Event Report Forms. Data such as:

- ° Time to cool down unit before component repairs can be initiated;
- ° Time servicing is delayed as well as cause of servicing delay;
- ° Work crew size and man-hours spent on component repair;
- ° Time component servicing initiated and completed;

are needed to perform the AIM calculations. This data is referred to in the methodology as the unit historical data. The historical data combined with the improvement project are used to generate hypothetical plant data, which is assumed to represent the behavior of the plant following the implementation of the improvement project. The methodology then evaluates the historical and hypothetical plant data to determine the ΔEUF_F and ΔEUF_{EE} parameters in equation (1). Consequently, the methodology provides a productivity improvement prediction which is dependent on the unit's historical operating and maintenance practices.

This handbook contains an example of properly completed GADS forms and details of how the collected data is applied in the methodology's reliability equations. Also described is how a root cause analysis can be performed so an improvement project can be defined as well as procedures to calculate the cost/benefit ratio for a prospective improvement project.

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* $\Delta EAF = \frac{1}{365} \times 100 = .274\%$

The purpose of this handbook is to provide step-by-step instructions which permit application of the AIM methodology without the need to be a reliability specialist. This is accomplished by simplifying the equations and streamlining the computations needed to evaluate prospective improvement projects.

To assist the user in understanding the AIM methodology and procedures, the handbook is divided into the following sections:

- Section 2.0   STEP-BY-STEP PROCEDURES IN APPLYING
THE METHODOLOGY

The procedures to be followed are outlined in this section. The construction of the unit model and application of the unit's historical data for evaluation of the productivity improvement projects are explained.

- Section 3.0   DEFINITIONS

All concepts and symbols with their physical interpretations are listed so the user can understand the equations presented in the handbook.

- Section 4.0   DATA COLLECTION

This section describes the type of data that needs to be collected on the GADS data forms and how it should be organized for the step-by-step analysis.

- Section 5.0   EQUATIONS

An organized listing of the basic reliability equations used in the methodology are given. The simplified equations are further broken down into tables and formulas for easy application in analyzing systems containing parallel components.

- Section 6.0   DETAILED EXAMPLES

Five examples are shown in this section to illustrate the step-by-step calculations and to demonstrate some of the various types of problems that can be analyzed by this method. Typical data organizing and handling problems are also included.

• APPENDICES

To elaborate on some of the other aspects of the methodology, three appendices have been included:

- Appendix A - GADS Cause/Component Codes

In order to identify recurring problems in similar plant equipment, event types resulting in outages, derates, etc., are reported by cause/component codes. This appendix presents a detailed listing of the GADS cause/component codes for identifying plant equipment and outage causes.

- Appendix B - Root Cause Analysis

This appendix describes how an investigation can be conducted for determining the root cause of an event by use of a logic tree approach.

- Appendix C - Financial and Benefit/Cost Analysis

The cost analysis aspects of the improvement programs are discussed in order to prioritize the improvement programs on a benefit/cost basis.

1.2 GENERAL REQUIREMENTS FOR USE OF METHODOLOGY

This handbook is written for the user with a hand calculator and good background in mathematics, including some algebra. In addition, the user should have a good understanding of a power plant's operation, maintenance, and outage procedures. Immediate and free access to plant and equipment outage data is also needed by those wishing to use this methodology.

It should be emphasized that a background in statistics and reliability methods is not necessary to utilize the methodology developed in this handbook. The procedural steps of the manual have been reduced to such elementary steps that the probabilistic-statistical origin of the analysis does not need to be understood. Much more important than an understanding of statistics is an understanding of a plant's one-line diagram and how various systems and subsystems interrelate during plant operation.

Although the manual and the procedures do not require a background in programming or a computer facility for immediate application on a plant model, the procedures and equations

are easily amenable to automatic data processing. This is especially true, and even advisable, if a computerized data base exists for various outage and maintenance events.

1.3 DATA COLLECTION AND STORAGE REQUIREMENTS

To apply the AIM methodology, failure, repair, and maintenance data must be collected at a fine level of detail. GADS Performance and Event Report Forms are used for this purpose. Other data methods may be used, but at least the level of data described in the sample GADS data sheets are needed if an analysis of the type explained in this handbook is to be conducted. If data is lacking, estimates may be used based on the experience of operating personnel and on engineering judgment. The methodology will provide a systematic procedure for ranking alternatives.

In order for AIM to establish a credible Δ EAF for an improvement project, approximately six component events are needed. For components that have frequent failures (i.e., boiler tubes), this amount of data may be collected in a relatively short period of time, such as a year. For components that fail less frequently (i.e., boiler circulation pumps), it might require several years before a sufficient data base is established and AIM can be used to evaluate an improvement project.

The need for large amounts of plant performance data requires that the data collection, storage, and retrieval be planned in a systematic manner so that the data will eventually be available in a credible and usable format. To aid in keeping track of this data, GADS cause/component codes are presented in Appendix A. This numbering scheme is flexible and permits easy identification, storage, and retrieval of data and is amenable to computerized methods where such facilities exist.

Another important aspect of data preparation is storage. Plant data is often distributed among operating logs, maintenance and repair work orders, and individual component repair records. These are stored in various departments at either the plant or headquarters. In time, this data may be discarded, lost, or misplaced. Reliability calculations are often carried out several years after an event takes place. It is difficult, if not impossible, to separate and correlate data months or years after events take place.

This process is further aggravated by such plant events as overlapping and multiple failures and events resulting in different levels of derates.

To avoid, or at least minimize, data base deterioration and to maintain adequately detailed reliable data, it must be correlated and stored in a systematic manner. To do this, data should be systematically recorded on the GADS Performance and Event Report Forms. Use of these data forms will allow the utility engineer to reconstruct an event years after it has occurred.

As a last item to consider in collecting and storing data, it should be pointed out that proper data management is a time-consuming process. Collection and preparation of the data consume a majority of the time spent in doing reliability analysis. Once the data is in the proper format, evaluation of the reliability equations and determination of the availability factors for a particular improvement project can be carried out in only a few hours.

The successful application of the AIM methodology depends on:

- ° Adequate data being available to the detailed level of analysis required;
- ° Person(s) dedicated to the task of applying the methodology who have a good knowledge of the entire plant's operation and history;
- ° Adequate time available to carry out the data collection, processing, and procedural steps of the methodology.

1.4 PRELIMINARY SCREENING OF PROSPECTIVE IMPROVEMENT PROJECTS

Most plants have a qualitative ranking of the systems and components that are causing the majority of their outages. An example is given in references [7] and [8]. This list can be used in a preliminary screening of possible improvement projects. With this list, the AIM methodology can be used to develop a quantitative assessment of the increase in generation that results from specific improvement projects. Based on the costs associated with implementing various improvement projects, utility management can determine the economic merits of each project and whether or not such projects should be undertaken.

2.0. STEP-BY-STEP PROCEDURES FOR THE AIM METHODOLOGY

This section of the handbook describes the procedures that are to be followed in using the AIM methodology. The application of the methodology has been divided into the following steps:

- STEP 1: Define level of detail for collecting component and external/economic event data
- STEP 2: Collect and format historical unit data on GADS Performance Report Forms and Event Report Forms
- STEP 3: Define improvement project
- STEP 4: Develop assumptions for the improvement project effect on unit historical GADS data obtained in Step 2
- STEP 5: Calculate historical equivalent unavailability factors for the component on which improvement project is to be evaluated
- STEP 6: Calculate equivalent unavailability factors for component with improvement project implemented using assumptions developed in Step 4
- STEP 7: Evaluate change in unit equivalent availability factor
- STEP 8: Evaluate benefit/cost of improvement project

Each of these steps is described in detail in this section.

STEP 1: Define Level of Detail for Collecting Component and External/Economic Event Data

A list of systems, components, parts, and even subparts needs to be developed for the unit. This equipment list defines the level of component event data which need to be collected for use of the methodology.

The GADS cause/component code list included in Appendix A of this handbook can be used to establish the level of detail for recording component and external/economic event data. In using the GADS cause/component code, events with code numbers between 0001-8999 can be treated as component events, while events with cause code numbers between 9000 and 9999 can be treated as external/economic events.

Determining the components for which event data is to be collected defines the elements of the reliability model. There is no maximum or minimum number of elements that the methodology requires for its application. In general, the more elements in the unit model, the more detailed improvement projects can be evaluated by the methodology. However, increasing the number of elements will also increase the time and manpower requirements to apply the methodology.

STEP 2: Collect and Format Unit Historical Data on GADS Performance Report Forms and Event Report Forms

As discussed in section 4.0, AIM calculations are based primarily on data contained in the Generating Availability Data System (GADS) reporting forms. Sections 4.1 and 4.2 describe how the GADS Performance Report Forms (PRF's) and Event Report Forms (ERF's) should be completed to perform AIM calculations.

In addition to collecting the GADS event data, the following information is suggested to be collected in order to allow AIM to evaluate a wider range of improvement projects:

- ° Unit cool-down time before equipment servicing can be initiated

For example, in a coal plant, if waterwall tube leaks are to be repaired, the time required to cool the unit down before the work crew can physically enter the boiler and initiate repair of the waterwall tubes.

- ° Number of parallel components in systems within unit

This information is needed to analyze improvement projects on systems containing parallel components.

- ° Number of parallel components needed for the unit to achieve gross maximum capacity

The number of parallel components in a system required to be operational at each component's maximum rated capacity for the unit to achieve its gross maximum capacity, if known, allows the methodology to compute the equivalent meantime-to-event (eM) for a system containing parallel components.

- ° Component's serviceability with unit on-line

This information can be used by the AIM methodology in computing the equivalent meantime-to-event (eM) for systems containing parallel components. In general, systems containing parallel components that are serviceable with the unit on-line have larger equivalent meantime-to-events (eM) than systems with parallel components that are serviceable only with a unit outage.

- ° Unit gross available capacity when a system or some number of components in a system are out-of-service

The resultant unit gross available capacity (GAC) due to a system not being operational or component(s) in a system containing parallel components being out-of-service must be known, assuming all other components and systems in the unit are in service and fully operational, in order to evaluate an improvement project on such a system.

For a system containing parallel components, the unit gross available capacity should be known as a function of the total number of components out-of-service. For example, if a unit has three parallel condensate pumps, the unit gross available capacity needs to be known if one (1), two (2), or three (3) of the condensate pumps are out-of-service if an improvement project on this system is to be evaluated.

STEP 3: Define Improvement Project

The AIM methodology is used to evaluate the effects on plant availability of improvement projects. For example, an improvement project to be evaluated could involve adding more redundant components to a system or installing more reliable components in a system. Section 6.0 of the handbook shows how the AIM methodology can be used to assess the change in plant equivalent availability factor by instituting five different improvement projects.

STEP 4: Develop Assumptions on the Effect of the Improvement Project on Unit Historical GADS Data Developed in Step 2

With a specific improvement project defined in Step 3, engineering assumptions must be developed showing the effect of the improvement project on the unit historical event data developed in Step 2. The assumptions developed must consider the impact of the improvement project on all historical data collected, which includes:

- ° Unit historical equipment event data;
- ° Unit historical external/economic event data;
- ° Unit historical gross available capacity over the time period event data has been collected.

These assumptions are then used to generate in Step 6 hypothetical event data for the unit which, when analyzed with the unit historical data, determine the effect of the improvement project on the unit equivalent availability factor.

STEP 5: Calculate Historical Equivalent Unavailability Factors for the Component on which Improvement Project is to be Evaluated

Using the unit historical GADS data collected in Step 2 and equations described in section 5.0, the historical equivalent unavailability factors are calculated. Only the events associated with the component(s) on which the improvement project is to be determined need to be used to calculate these factors. For example, if a pulverizer improvement project is to be evaluated, only pulverizer and associated concurrent

events need to be analyzed using the GADS data base. The EUF parameters calculated in this step are the unit equivalent unavailability factor due to a particular component (EUF_F) and/or external/economic events (EUF_{EE})_{no}. It is not necessary to compute an overall unit EUF to apply the AIM methodology.

STEP 6: Calculate Equivalent Unavailability Factors for Component with Improvement Project Implemented Using Assumptions Developed in Step 4

Using the unit historical GADS data and supplemental data collected in Step 2, the assumptions developed in Step 4, and the equations described in section 5.0, component and external/economic hypothetical event data is constructed. Section 4.3 describes the construction of unit hypothetical data from unit historical data.

A useful tool to aid in the calculation of these hypothetical reliability parameters (EUF_F and EUF_{EE}) is the construction of a unit hypothetical gross available generation (GAG) profile. This procedure is described in five examples in sections 6.3 through 6.7. The hypothetical GAG profile is the unit gross available capacity had the improvement project been implemented over the time period for which GADS data has been collected.

STEP 7: Evaluate Change in Unit Equivalent Availability Factor

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Inserting the (EUF_F)_{no} and (EUF_{EE})_{no} parameters developed in Step 5 and the EUF_F and EUF_{EE} parameters from Step 6 into the following equation:

$$\Delta EAF = -\Delta EUF_F - \Delta EUF_{EE} \quad (1)$$

where

$$\Delta EUF_F = EUF - (EUF_F)_{no}$$

$$\Delta EUF_{EE} = EUF_{EE} - (EUF_{EE})_{no}$$

gives the change in the unit equivalent availability factor (ΔEAF) for implementing the improvement project.

STEP 8: Evaluate Benefit/Cost of Improvement Project

Using the ΔEAF obtained for the improvement project in Step 7, the financial and benefit/cost of implementing the improvement project is performed. The procedures and equations for this analysis are described in Appendix C.

3.0 DEFINITIONS

The terminology adopted for AIM uses utility standard definitions, such as GADS and IEEE definitions. For parameters not defined by IEEE definitions, different words have been used to avoid confusion with the standard IEEE definitions.

This section is composed primarily of Table 1 which contains six columns with the following information:

- An alphabetical list of all the symbols used in the methodology (column 1);
- The parameter characterized by an appropriate symbol (column 2);
- The definition of the parameter including, where possible, a physical interpretation of the parameter (column 3);
- The equation(s) used to calculate the parameter or the GADS data form from which the parameter can be found (column 4);
- Units of parameters (column 5);
- General comments regarding the parameters or assumption on which the equation to calculate the parameter is based (column 6).

Table 1 is intended as a reference for the terminology and symbols used in this handbook. It is expected that the reader will refer to Table 1 while reading the next three sections (4.0 through 6.0). It is suggested that Table 1 not be read at this time, but only referenced to as unfamiliar symbols or terminology arise in the following sections of the handbook.

TABLE 1

DEFINITIONS AND EQUATIONS FOR PARAMETERS USED IN HANDBOOK

SYMBOL	PARAMETER	DEFINITION/PHYSICAL MEANING	EQUATION(S)/DATA FORMAT LOCATION	UNITS	COMMENTS
$(cs)_i$	Crew size with improvement project implemented	Average crew size assigned to physically service component in i th hypothetical component event	Data determined by estimating effect of improvement project on $(csno)_i$	Persons	
$(csno)_i$	Crew size without improvement project implemented	Average crew size assigned to physically service component in i th historical component event	Data read from GADS ERF's for event i (card 02 or 03, under verbal description)	Persons	Data not required by GADS.
em	Equivalent meantime-to-restore with improvement project implemented while component or system limiting unit gross available capacity	$\left(\begin{array}{l} \text{Megawatt hours lost by unit due to} \\ \text{hypothetical component events over} \\ \text{given period of time} \end{array} \right)$ $\left(\begin{array}{l} \text{Number of hypothetical} \\ \text{events occurring with} \\ \text{component over given} \\ \text{period of time} \end{array} \right) \quad \left(\begin{array}{l} \text{Unit Gross} \\ \text{Maximum} \\ \text{Capacity} \end{array} \right)$	$em = \frac{\sum_{i=1}^n (UND)_i (m)_i}{(n) (GMC)}$ $em = em_1 + em_2 + em_3$	Hours	$(UND)_i$ may vary over event i duration if there are concurrent events.
em_{no}	Equivalent meantime-to-restore before improvement project implemented while component or system limiting unit gross available capacity	$\left(\begin{array}{l} \text{Megawatt hours lost by unit due to} \\ \text{historical component events over} \\ \text{given period of time} \end{array} \right)$ $\left(\begin{array}{l} \text{Number of historical} \\ \text{events occurring with} \\ \text{component over given} \\ \text{time period} \end{array} \right) \quad \left(\begin{array}{l} \text{Unit Gross} \\ \text{Maximum} \\ \text{Capacity} \end{array} \right)$	$em_{no} = \frac{\sum_{i=1}^{n_{no}} (UND_{no})_i (m_{no})_i}{(n_{no}) (GMC)}$ $em_{no} = em_{no_1} + em_{no_2} + em_{no_3}$	Hours	$(UND_{no})_i$ may vary over event i duration if there are concurrent events.
em_1	Equivalent meantime for unit cool-down with improvement project implemented while component or system limiting unit gross available capacity	$\left(\begin{array}{l} \text{Megawatt hours lost by unit while} \\ \text{cooling down before service on com-} \\ \text{ponent can be initiated due to} \\ \text{hypothetical component events over} \\ \text{given period of time} \end{array} \right)$ $\left(\begin{array}{l} \text{Number of hypothetical} \\ \text{events occurring with} \\ \text{component over given} \\ \text{time period} \end{array} \right) \quad \left(\begin{array}{l} \text{Unit Gross} \\ \text{Maximum} \\ \text{Capacity} \end{array} \right)$	$em_1 = \frac{\sum_{i=1}^n (UND)_i (m_1)_i}{(n) (GMC)}$	Hours	$(UND)_i$ may vary over event i duration if there are other concurrent events.
$(em_{no})_1$	Equivalent meantime for unit cool-down without improvement project implemented while component or system limiting unit gross available capacity	$\left(\begin{array}{l} \text{Megawatt hours lost by unit while} \\ \text{cooling down before service on com-} \\ \text{ponent can be initiated due to his-} \\ \text{torical component events over given} \\ \text{period of time} \end{array} \right)$ $\left(\begin{array}{l} \text{Number of historical} \\ \text{events occurring with} \\ \text{component over given} \\ \text{time period} \end{array} \right) \quad \left(\begin{array}{l} \text{Unit Gross} \\ \text{Maximum} \\ \text{Capacity} \end{array} \right)$	$em_{no_1} = \frac{\sum_{i=1}^{n_{no}} (UND_{no})_i (m_{no_1})_i}{(n_{no}) (GMC)}$	Hours	
(...continued)					

DEFINITIONS AND EQUATIONS FOR PARAMETERS USED IN HANDBOOK (Continued)

SYMBOL	PARAMETER	DEFINITION/PHYSICAL MEANING	EQUATION(S)/DATA FORMAT LOCATION	UNITS	COMMENTS
em_2	Equivalent meantime service delayed after improvement project implemented while component or system limiting unit gross available capacity	$\left(\begin{array}{l} \text{Megawatt hours lost by unit due to} \\ \text{service delays on component due to} \\ \text{hypothetical component events over} \\ \text{given period of time} \end{array} \right)$ $\left(\begin{array}{l} \text{Number of hypothetical} \\ \text{events occurring with} \\ \text{component over given} \\ \text{time period} \end{array} \right) \left(\begin{array}{l} \text{Unit Gross} \\ \text{Maximum} \\ \text{Capacity} \end{array} \right)$	$em_2 = \frac{\sum_{i=1}^n (UND)_i (m_2)_i}{(n) (GMC)}$	Hours	
$(em_{no})_2$	Equivalent meantime service delayed before improvement project implemented while component or system limiting unit gross available capacity	$\left(\begin{array}{l} \text{Megawatt hours lost by unit due to} \\ \text{service delays on component due to} \\ \text{historical events over given period} \\ \text{of time} \end{array} \right)$ $\left(\begin{array}{l} \text{Number of historical} \\ \text{events occurring with} \\ \text{component over given} \\ \text{time period} \end{array} \right) \left(\begin{array}{l} \text{Unit Gross} \\ \text{Maximum} \\ \text{Capacity} \end{array} \right)$	$(em_{no})_2 = \frac{\sum_{i=1}^{n_{no}} (UND_{no})_i (m_{no2})_i}{(n_{no}) (GMC)}$	Hours	
em_3	Equivalent meantime to physically service by work crew after improvement project implemented while component or system limiting unit gross available capacity	$\left(\begin{array}{l} \text{Megawatt hours lost by unit while work} \\ \text{crew physically services component due} \\ \text{to hypothetical component events over} \\ \text{given period of time} \end{array} \right)$ $\left(\begin{array}{l} \text{Number of hypothetical} \\ \text{events occurring with} \\ \text{component over given} \\ \text{time period} \end{array} \right) \left(\begin{array}{l} \text{Unit Gross} \\ \text{Maximum} \\ \text{Capacity} \end{array} \right)$	$em_3 = \frac{\sum_{i=1}^n (UND)_i (m_3)_i}{(n) (GMC)}$	Hours	
$(em_{no})_3$	Equivalent meantime to physically service by work crew before improvement project implemented while component or system limiting unit gross available capacity	$\left(\begin{array}{l} \text{Megawatt hours lost by unit while work} \\ \text{crew physically services component due} \\ \text{to historical component events over} \\ \text{given period of time} \end{array} \right)$ $\left(\begin{array}{l} \text{Number of historical} \\ \text{events occurring with} \\ \text{component over given} \\ \text{time period} \end{array} \right) \left(\begin{array}{l} \text{Unit Gross} \\ \text{Maximum} \\ \text{Capacity} \end{array} \right)$	$(em_{no})_3 = \frac{\sum_{i=1}^{n_{no}} (UND_{no})_i (m_{no3})_i}{(n_{no}) (GMC)}$	Hours	
			(...continued)		

DEFINITIONS AND EQUATIONS FOR PARAMETERS USED IN HANDBOOK (Continued)

SYMBOL	PARAMETER	DEFINITION/PHYSICAL MEANING	EQUATION(S)/DATA FORMAT LOCATION	UNITS	COMMENTS
eM	Equivalent meantime-to-event for component or system after improvement project implemented at unit	(Unit hypothetical service hours in given time period) Number of hypothetical events for component or system which result in a reduction in unit gross available capacity in a given time period	Single component system $eM = M_1$ System containing parallel components repairable with unit on-line $eM = \frac{\sum_{j=r}^{n'} \binom{n'}{j} M_1^j m^{n'-j}}{n' \binom{n'-1}{r-1} M_1^{(r-1)} m^{(n'-r)}}$ System containing parallel components repairable only with unit outage $eM = M_1 \sum_{j=r}^{n'} \frac{(j-1)!}{j!}$	Hours	Formulas for parallel components assume identical parallel components in system. Table for these values given in section 5.1.1.
eM _{no}	Equivalent meantime-to-event for component or system before improvement project implemented at unit	(Unit historical service hours in given time period) Number of historical events for component or system which result in a reduction in unit gross available capacity in a given time period	Single component system. $eM_{no} = M_{1no}$ System containing parallel components repairable with unit on-line $eM_{no} = \frac{\sum_{j=r_{no}}^{n'_{no}} \binom{n'_{no}}{j} M_{1no}^j m_{no}^{n'_{no}-j}}{n'_{no} \binom{n'_{no}-1}{r_{no}-1} M_{1no}^{(r_{no}-1)} m_{no}^{(n'_{no}-r_{no})}}$ System containing parallel components repairable only with unit outage $eM_{no} = M_{1no} \sum_{j=r_{no}}^{n'_{no}} \frac{(j-1)!}{j!}$	Hours	Formulas for parallel components assume identical parallel components in system. Tables for these values given in section 5.1.1.
			(...continued)		

DEFINITIONS AND EQUATIONS FOR PARAMETERS USED IN HANDBOOK (Continued).

SYMBOL	PARAMETER	DEFINITION/PHYSICAL MEANING	EQUATION(S)/DATA FORMAT LOCATION	UNITS	COMMENTS
EUF_{EE}	Unit equivalent unavailability factor due to external/economic events with improvement project implemented	$\frac{\left(\text{Megawatt hours lost by unit due to hypothetical external/economic events in given period of time} \right)}{\left(\text{Megawatt hours unit could have generated in given period of time if continuously operated at its gross maximum capacity} \right)} \times 100$	$EUF_{EE} = \frac{\sum_{i=1}^{n_{EE}} \left[\left((t_{1EE})_i - (t_{0EE})_i \right) (UND_{EE})_i \right]}{(PH) (GMC)} \times 100$	Percent (%)	
$EUF_{EE_{no}}$	Unit equivalent unavailability factor due to external/economic events without improvement project implemented	$\frac{\left(\text{Megawatt hours lost by unit due to historical external/economic events in given period of time} \right)}{\left(\text{Megawatt hours unit could have generated in given period of time if operated continuously at its gross maximum capacity} \right)} \times 100$	$EUF_{EE_{no}} = \frac{\sum_{i=1}^{(n_{EE})_{no}} \left[\left((t_{iEE_{no}})_i - (t_{0EE_{no}})_i \right) (UND_{EE_{no}})_i \right]}{(PH) (GMC)} \times 100$	Percent (%)	
ΔEUF_{EE}	Change in unit equivalent unavailability factor due to external/economic events following implementation of improvement project	$\frac{\left(\text{Change in megawatt hours lost by unit due to external/economic events following implementation of improvement project over given period of time} \right)}{\left(\text{Megawatt hours unit could have generated in given period of time if operated continuously at its gross maximum capacity} \right)} \times 100$	$\Delta EUF_{EE} = EUF_{EE} - (EUF_{EE})_{no}$	Percent (%)	
EUF_F	Unit equivalent unavailability factor due to component events with improvement project implemented	$\frac{\left(\text{Megawatt hours lost by unit due to hypothetical component events in given period of time} \right)}{\left(\text{Megawatt hours unit could have generated in given period of time if operated continuously at its gross maximum capacity} \right)} \times 100$	$EUF_F = \left(\frac{\bar{e}_m}{e_M} \right) \frac{SH}{PH} \times 100$	Percent (%)	
$EUF_{F_{no}}$	Unit equivalent unavailability factor due to component events without improvement project implemented	$\frac{\left(\text{Megawatt hours lost by unit due to historical component events in given period of time} \right)}{\left(\text{Megawatt hours unit could have generated in given period of time if operated continuously at its gross maximum capacity} \right)} \times 100$	$EUF_{F_{no}} = \left(\frac{e_{m_{no}}}{e_{M_{no}}} \right) \frac{SH_{no}}{PH} \times 100$	Percent (%)	
			(...continued)		

DEFINITIONS AND EQUATIONS FOR PARAMETERS USED IN HANDBOOK (Continued)

SYMBOL	PARAMETER	DEFINITION/PHYSICAL MEANING	EQUATION(S)/DATA FORMAT LOCATION	UNITS	COMMENTS
ΔEAF	Change in unit equivalent availability factor	Change in unit equivalent availability factor following implementation of improvement project. Physically, ΔEAF is 100 times the additional megawatt hours of energy the unit is available to generate, divided by the megawatt hours the unit could generate in a given time period operating at its gross maximum capacity after implementing improvement project.	$\Delta EAF = -\Delta EUF_F - \Delta EUF_{EE}$ $\Delta EAF = \frac{\left(\begin{array}{c} \text{Additional megawatt} \\ \text{hours unit is available} \\ \text{to generate following} \\ \text{implementation of} \\ \text{improvement project in} \\ \text{time period PH} \end{array} \right)}{(PH) (GMC)} \times 100$	Percent (%)	EAF defined as: $EAF = \frac{GAG}{PH \times GMC} \times 100$
ΔEUF_F	Change in unit equivalent unavailability factor due to component events following implementation of improvement project	$\left(\begin{array}{c} \text{Change in megawatt hours lost by} \\ \text{unit due to component events} \\ \text{following implementation of} \\ \text{improvement project over} \\ \text{given period of time} \end{array} \right) \times 100$ $\left(\begin{array}{c} \text{Megawatt hours unit could have} \\ \text{generated in given period of} \\ \text{time if operated continuously} \\ \text{at its gross maximum capacity} \end{array} \right)$	$\Delta EUF_F = EUF_F - EUF_{F_{no}}$	Percent (%)	
GAC_i	Gross available capacity with improvement project implemented	Unit gross available capacity as a result of i^{th} hypothetical event	Determined by estimating effect of improvement project to $(GAC_{no})_i$	Megawatts (MW)	Unit gross available capacity equals unit GDC modified for equipment limitation at time of event
$(GAC_{no})_i$	Gross available capacity without improvement project implemented	Unit gross available capacity as a result of i^{th} historical event	Read from GADS ERF (card 01, columns 54-57) for event i	Megawatts (MW)	Unit gross available capacity equals unit GDC modified for equipment limitation at time of event
$(GAC_{EE})_i$	Unit gross available capacity as a result of external/economic event with improvement project implemented	Unit gross available capacity as a result of hypothetical external/economic event i	Determined by estimating effect of improvement project to $(GAC_{EE_{no}})_i$	Megawatts (MW)	
$(GAC_{EE_{no}})_i$	Unit gross available capacity as a result of external/economic event without improvement project implemented	Unit gross available capacity as a result of historical external/economic event i	Read from GADS ERF (card 01, columns 54-57) for event i	Megawatts (MW)	
GAG	Gross available generation	The gross energy that could have been generated by unit in given time period if operated continuously at its gross available capacity	$GAG = GAC \times PH$	Megawatts (MW)	
			(...continued)		

DEFINITIONS AND EQUATIONS FOR PARAMETERS USED IN HANDBOOK (Continued)

SYMBOL	PARAMETER	DEFINITION/PHYSICAL MEANING	EQUATION(S)/DATA FORMAT LOCATION	UNITS	COMMENTS
GDC	Gross dependable capacity	Unit gross maximum capacity modified for ambient limitations for specified period of time	Recorded on GADS PRF (card 01, columns 18-21)	Megawatts (MW)	
GDC_i^*	Shadowed unit gross dependable capacity	Either (a) unit gross dependable capacity in event i if no other concurrent events occurring in unit (excluding noncurtailing events) or (b) unit GDC as a result of other concurrent events in unit	$GDC_i^* = GDC$ (no concurrent events in unit) $GDC_i^* = \text{Min. } (GDC)_j$ (concurrent events j with event i)	Megawatts (MW)	
GMC	Gross maximum capacity	Maximum capacity a unit can sustain over given period of time	Recorded on GADS PRF (card 01, columns 14-17)	Megawatts (MW)	
M_1	Meantime-to-event for single component with improvement project implemented	$\frac{\left(\begin{array}{c} \text{System operational time with improvement project implemented in given period of time} \\ \text{(Number of hypothetical events for component in given time period)} \end{array} \right)}{}$	$M_1 = r \frac{SH}{n}$	Hours	
M_{1no}	Meantime-to-event for single component without improvement project implemented	$\frac{\left(\begin{array}{c} \text{System operation time without improvement project implemented in given period of time} \\ \text{(Number of historical events for component in given time period)} \end{array} \right)}{}$	$M_{1no} = r_{no} \frac{SH_{no}}{n_{no}}$	Hours	
m	Meantime-to-restore single component with improvement project implemented	Average time to restore single component with improvement project implemented	$m = \frac{1}{n} \sum_{i=1}^n \left[(m_1)_i + (m_2)_i + (m_3)_i \right]$	Hours	
$(m)_{no}$	Meantime-to-restore single component without improvement project implemented	Average time to restore single component without improvement project implemented	$(m)_{no} = \frac{1}{n_{no}} \sum_{i=1}^{n_{no}} \left[(m_{1no})_i + (m_{2no})_i + (m_{3no})_i \right]$	Hours	
			(...continued)		

DEFINITIONS AND EQUATIONS FOR PARAMETERS USED IN HANDBOOK (Continued)

SYMBOL	PARAMETER	DEFINITION/PHYSICAL MEANING	EQUATION(S)/DATA FORMAT LOCATION	UNITS	COMMENTS
$(m_1)_i$	Time for unit cool-down with improvement project implemented	Time for unit cool-down in i^{th} component hypothetical event	Data determined by estimating impact of improvement project on $(m_{1no})_i$	Hours	
$(m_{1no})_i$	Time for unit cool-down without improvement project implemented	Time for unit cool-down in i^{th} component historical event	Data read from verbal description for event i on GADS ERF (card 02 or 03, under verbal description)	Hours	Data not required by GADS
$(m_2)_i$	Time component service delayed with improvement project implemented	Time component service delayed in i^{th} hypothetical event	Data determined by estimating impact of improvement project on $(m_{2no})_i$	Hours	
$(m_{2no})_i$	Time component service delayed without improvement project implemented	Time component service delayed in i^{th} historical event	Data read from verbal description for event i on GADS ERF (card 02 or 03, under verbal description)	Hours	Data not required by GADS
$(m_3)_i$	Time to physically service component with improvement project implemented	Time to physically service component in i^{th} hypothetical event	$(m_3)_i = \frac{(t_{mh})_i}{(cs)_i}$	Hours	
$(m_{3no})_i$	Time to physically service component without improvement project implemented	Time to physically service component in i^{th} historical event	$(m_{3no})_i = \frac{(t_{mhno})_i}{(csno)_i}$	Hours	
n	Number of components in system with improvement project implemented	Total number of parallel components in system with improvement project implemented	Data found from unit design information	---	
n_{no}	Number of components in system without improvement project implemented	Total number of parallel components in system without improvement project implemented	Data found from unit design information	---	
n_{no}	Number of component events without improvement project implemented	Number of historical events for a component or system in given period of time	Data determined from GADS ERF for unit	---	
			(...continued)		

DEFINITIONS AND EQUATIONS FOR PARAMETERS USED IN HANDBOOK (Continued)

SYMBOL	PARAMETER	DEFINITION/PHYSICAL MEANING	EQUATION(S)/DATA FORMAT LOCATION	UNITS	COMMENTS
$(n_{EE})_{no}$	Number of historical external/economic events without improvement project implemented	Number of historical external/economic events in given period of time	Data determined from GADS ERF for unit	---	
n	Number of component events with improvement project implemented	Number of hypothetical events for a component or system in given period of time	Data determined by estimating effect of improvement project on GADS ERF's for unit	---	
n_{EE}	Number of external/economic events with improvement project implemented	Number of hypothetical external/economic events in a given period of time	Data determined by estimating effect of improvement project on GADS ERF's for unit	---	
PH	Period hours	Hours in a given period time	Determined from GADS PRF for unit (card 02, columns 54-57)	Hours	
r	Number of components in a system required for unit to achieve its gross maximum capacity with improvement project implemented	Number of parallel components in a system required in operation for unit to achieve its gross maximum capacity with improvement project implemented	Data found from unit design information	---	
r_{no}	Number of components in a system required for unit to achieve its gross maximum capacity without improvement project implemented	Number of parallel components in a system required in operation for unit to achieve its gross maximum capacity without improvement project implemented	Data found from unit design information	---	
SH	Unit service hours with improvement project implemented	Hours generator is synchronized in a given period of time with improvement project implemented	$SH = SH_{no} + \Delta SH$	Hours	
SH_{no}	Unit service hours without improvement project implemented	Hours generator is synchronized in a given period of time without improvement project implemented	Determined from GADS PRF for unit (card 02, columns 14-17)	Hours	
			(...continued)		

DEFINITIONS AND EQUATIONS FOR PARAMETERS USED IN HANDBOOK (Continued)

SYMBOL	PARAMETER	DEFINITION/PHYSICAL MEANING	EQUATION(S)/DATA FORMAT LOCATION	UNITS	COMMENTS
ΔSH	Change in time generator synchronized following implementation of improvement project	Change in hours generator is synchronized in given period of time based on implementation of improvement project	Determined by estimating effect of improvement project on SH_{no}	Hours	
$(t_{oEE})_i$	Time hypothetical external/economic event initiated	Time (month·day·hour·minute) i^{th} hypothetical external/economic event initiated	Data determined by estimating effect of improvement project on $(t_{oEE_{no}})_i$	Month·day·hour·minute	
$(t_{oEE_{no}})_i$	Time historical external/economic event initiated	Time (month·day·hour·minute) i^{th} historical external/economic event initiated	Data read from GADS ERF for event i (card 01, columns 18-25)	Month·day·hour·minute	
$(t_{lEE})_i$	Time hypothetical external/economic event terminated	Time (month·day·hour·minute) i^{th} hypothetical external/economic event terminated	Data determined by estimating effect of improvement project on $(t_{lEE_{no}})_i$	Month·day·hour·minute	
$(t_{lEE_{no}})_i$	Time historical external/economic event terminated	Time (month·day·hour·minute) i^{th} historical external/economic event terminated	Data read from GADS ERF for event i (card 01, columns 46-53)	Month·day·hour·minute	
$(t_{mh})_i$	Man-hours spent to service component in hypothetical event i	Man-hours spent to service component in i^{th} hypothetical event i	Data determined by estimating effect of improvement project on $(t_{mh_{no}})_i$	Man-Hours	
$(t_{mh_{no}})_i$	Man-hours spent to service component in historical event i	Man-hours spent to service component in i^{th} historical event	Data read from GADS ERF for event i (card 02, columns 44-47)	Man-Hours	
$(UND)_i$	Unit derating in event i following implementation of improvement project	Reduction in unit gross available capacity due to i^{th} hypothetical event	$(UND)_i = GDC_i^* - GAC_i$	Megawatts (MW)	Can vary over duration of event i
			(...continued)		

DEFINITIONS AND EQUATIONS FOR PARAMETERS USED IN HANDBOOK (Continued)

SYMBOL	PARAMETER	DEFINITION/PHYSICAL MEANING	EQUATION(S)/DATA FORMAT LOCATION	UNITS	COMMENTS
$(UND_{no})_i$	Unit derating in event i without improvement project implemented	Reduction in unit gross available capacity due to i^{th} historical event	$(UND_{no})_i = GDC_i^* - (GAC_{no})_i$	Megawatts (MW)	Can vary over duration of event i
$(UND_{EE})_i$	Unit derating in external/economic event i following implementation of improvement project	Reduction in unit gross available capacity due to i^{th} hypothetical external/economic event	$(UND_{EE})_i = GDC_i^* - (GAC_{EE})_i$	Megawatts (MW)	Can vary over duration of event i
$(UND_{EE_{no}})_i$	Unit derating in external/economic event i without improvement project implemented	Reduction in unit gross available capacity due to i^{th} historical external/economic event	$(UND_{EE_{no}})_i = GDC_i^* - (GAC_{EE_{no}})_i$	Megawatts (MW)	Can vary over duration of event i

4.0 HISTORICAL DATA COLLECTION AND CONSTRUCTION OF UNIT HYPOTHETICAL DATA

This section of the handbook describes the data collection requirements of the AIM methodology. AIM calculations are based primarily on the data contained on the Generating Availability Data System (GADS) reporting forms. Several utilities are presently collecting equipment outage data on the GADS Performance and Event Report Forms. If properly developed, this data base is sufficient for performing most of the AIM calculations discussed in this handbook.

4.1 GADS PERFORMANCE REPORT FORM (PRF)

The GADS Performance Report Form (Figure 1) consists of three cards used to provide an overall summary of the operating results of a unit. Card 01 is used to identify the unit, the report period, the gross and net maximum capacity, and gross and net dependable capacity during the reporting period. The difference between the maximum and dependable capacities entered on card 01 accounts for any seasonal derates that the unit might be experiencing. Also entered on card 01 are the gross and net actual generation (MWHR) of the unit during the reporting period and the unit starting characteristics. The AIM methodology is based on the calculation of the change in equivalent availability factor as a result of various improvement projects and requires that the unit's gross maximum and gross dependable capacities be known during the period that serves as the AIM data base.

Card 02 of the PRF describes unit time information and lists the hours the unit operated in various modes, such as unit service hours, reserve shutdown, etc., during the reporting period. This data is a compilation of the GADS Event Report Forms and is used in the AIM methodology to establish the unit Service Hours (SH) and the Period Hours (PH) over which an improvement project is evaluated.

Card 03 of the PRF describes the primary and secondary fuel used in the operation of the unit. The data contained in this card is not used in performing AIM calculations and is, therefore, not included in this handbook. This data could, however, become important in performing benefit/cost analysis (Appendix C) associated with the various improvement projects that are evaluated by the AIM methodology.

PERFORMANCE REPORT FORM

UNIT NAME _____ UTILITY NAME _____
 REPORTED BY _____ PHONE NO _____ DATE _____

This Performance Report Form may be used for reporting *either* Quarterly or Monthly Performance Data.
 (See "Report Period" — Column 11 and 12.)

A—UNIT IDENTIFICATION

Data Card Code	Utility Code	Unit Code	Year	Report Period	Enter if: Monthly	Enter if: Quarterly	Report Revision Code
9 5					01 = Jan. 02 = Feb. 12 = Dec.	X1 = 1/1-3/31 X2 = 4/1-6/30 X3 = 7/1-9/30 X4 = 10/1-12/31	0-Original Report 1-9-Revisions
1 2	3 4 5	6 7 8	9 10	11 12			13

B—UNIT GENERATION PERFORMANCE*

Gross Maximum Capacity	Gross Dependable Capacity	Gross (MWHR) Actual Generation	*Gross Data Preferred • If Gross unavailable, report Net Data • If both Gross and Net Data available, report both.
14 17	18 21	22 28	
Net Maximum Capacity	Net Dependable Capacity	Net (MWHR) Actual Generation	
29 32	33 36	37 43	

C—UNIT STARTING CHARACTERISTICS

Typical Unit Loading Characteristics

- 44 ☐ 1—Base Loaded Minor Load-Following
☐ 2—Periodic Startup Load-Follow Daily Reduced Load Nightly
☐ 3—Weekly Startup Load-Follow Daily Reduce Load Nightly
☐ 4—Daily Startup Load-Follow Daily Off-line Nightly
☐ 5—Startup chiefly to meet Daily Peaks
☐ 6—Other. Describe in Columns 54-78

Number of Attempted Unit Starts	Actual Unit Starts
45 47	48 50

VERBAL DESCRIPTION (If #6 was used in Column 44)

54 57	58 78	79 80
		0 1

KEY PUNCH — Duplicate Columns 1-13 Card 01

D—UNIT TIME INFORMATION

Unit Service Hours	Reserve Shutdown Hours	Pumping Hours	Synchronous Condensing Hours	=	AVAILABLE HOURS
14 17	18 21	22 25	26 29		30 33
Planned Outage Hours (PØ)	Unplanned Outage Hours U1 + U2 + U3	Maintenance Outage Hours (MØ)	Extension of Scheduled Outages (SE)	=	UNAVAILABLE HOURS
34 37	38 41	42 45	46 49		50 53
					PERIOD HOURS
					54 57
					0 2
					79 80

Figure 1

4.2 GADS EVENT REPORT FORM (ERF)

The GADS Event Report Form (Figure 2) provides a detailed summary for each event that results in lost generation or noncurtailing outages due to equipment failures and/or external/economic events. This card must be properly filled out for each plant event and entered into a data base. After accumulating sufficient numbers of plant events that resulted in lost generation or noncurtailing equipment repairs, the data base can be used in the AIM methodology to evaluate various improvement projects.

ERF card 01 describes the event number and event type. As specified by the GADS instructions, event types indicate such operating occurrences as unplanned outages, plant deratings, and reserve shutdown for the unit for which data is being reported. Additionally, card 01 reports the time an event started (columns 18-25) and the time an event ended (columns 46-53), as well as any changes in the event type. The end of event as specified by GADS and used in the AIM calculations is that time at which the unit is synchronized to the system for outages and reserve shutdowns or the time at which the unit is actually or potentially increased in unit available capacity for derating events. AIM uses the difference of the start of event time and the end of event to calculate the actual hours over which the event lasted. Also on GADS ERF 01 is the gross available capacity as a result of event (columns 58-61) for events that result in a plant derating. AIM uses the gross available capacity as a result of an event in evaluating the effect of a proposed improvement project on such an event. This number should be the capacity that results from the event reported on the ERF if it acted independent of other events that might be occurring in the unit. It is not the gross capacity that is read from the station meter when the event is occurring as several concurrent events could also be acting to reduce the output of the unit.

Card 02 of the ERF describes the primary cause of the event. Columns 18-21 are used to list the system/component cause code (Appendix A) and are used in the AIM methodology to extract potential improvement projects from the data base. It is important that the correct cause code be used to describe each event and, if necessary, the cause of event should be further described in the verbal section of this card, if possible.

EVENT REPORT FORM

UNIT NAME _____ UTILITY NAME _____
 REPORTED BY _____ PHONE NO _____ DATE _____

A - EVENT IDENTIFICATION

Data Card Code 9 7 1 2	Utility Code 3 4 5	Unit Code 6 7 8	Year Event Started 9 10	Event Types P0 - Planned Outage SE - Extension of P0 or M0 U1 - Immediate U2 - Delayed U3 - Postponed PD - Planned Derating Unplanned Derating D1 - Immediate D2 - Delayed D3 - Postponed D4 - Deferred M0 - Maintenance Outage RS - Reserve Shutdown NC - Non-Curtailing Outage
Event Number 11 12 13 14	Report Revision Code 15 0-Original Report 1-9-Revisions	Event Type 16 17		

B - EVENT MAGNITUDE

Start of Event Month Day Hour Minute 18 19 20 21 22 23 24 25	Time: Change in Event Type Month Day Hour Minute 26 27 28 29 30 31 32 33	Event Type Changed To: 34 35	Allowable* Event Type Changes <table border="1"> <thead> <tr> <th>TO</th> <th>P0</th> <th>SE</th> <th>U1</th> <th>U2-U3</th> <th>M0</th> <th>RS</th> </tr> </thead> <tbody> <tr> <td>FROM P0</td> <td></td> <td>yes</td> <td>yes</td> <td>no</td> <td>no</td> <td>yes</td> </tr> <tr> <td>SE</td> <td>no</td> <td></td> <td>yes</td> <td>no</td> <td>no</td> <td>yes</td> </tr> <tr> <td>U1</td> <td>yes</td> <td>no</td> <td></td> <td>no</td> <td>yes</td> <td>yes</td> </tr> <tr> <td>U2-U3</td> <td>yes</td> <td>no</td> <td>yes</td> <td></td> <td>yes</td> <td>yes</td> </tr> <tr> <td>M0</td> <td>yes</td> <td>yes</td> <td>yes</td> <td>no</td> <td></td> <td>yes</td> </tr> <tr> <td>RS</td> <td>yes</td> <td>no</td> <td>yes</td> <td>no</td> <td>yes</td> <td></td> </tr> </tbody> </table>	TO	P0	SE	U1	U2-U3	M0	RS	FROM P0		yes	yes	no	no	yes	SE	no		yes	no	no	yes	U1	yes	no		no	yes	yes	U2-U3	yes	no	yes		yes	yes	M0	yes	yes	yes	no		yes	RS	yes	no	yes	no	yes	
TO	P0	SE		U1	U2-U3	M0	RS																																													
FROM P0		yes		yes	no	no	yes																																													
SE	no			yes	no	no	yes																																													
U1	yes	no		no	yes	yes																																														
U2-U3	yes	no	yes		yes	yes																																														
M0	yes	yes	yes	no		yes																																														
RS	yes	no	yes	no	yes																																															
Time: Change in Event Type Month Day Hour Minute 36 37 38 39 40 41 42 43	Event Type Changed To: 44 45	End of Event Month Day Hour Minute 46 47 48 49 50 51 52 53																																																		
(Report for Deratings Only)																																																				
Gross Available Capacity MWe As Result of Event ** 54 55 56 57	Net Available Capacity MWe As Result of Event 58 59 60 61	0 1 78 30																																																		

KEY PUNCH - Duplicate Columns 1-17 Card 01

C - PRIMARY CAUSE OF EVENT

System/Component Cause Code (See Appendix A) 18 19 20 21 22 23	Time: Work Started Month Day Hour Minute 24 25 26 27 28 29 30 31	Time: Work Completed Month Day Hour Minute 32 33 34 35 36 37 38 39	Man Hours Worked on This System/Component 40 41
Event Contribution Code 1 42 1-Primary Cause of Event	Problem Alert 43 Enter X only if cause is thought to be generic		
VERBAL DESCRIPTION 44 45 46 47 48 49 50 51 52 53 54 55 56 57 58 59 60 61 62 63 64 65 66 67 68 69 70 71 72 73 74 75 76 77 78			
0 2 78 30			

KEY PUNCH - Duplicate Columns 1-17 Card 01

System/Component Cause Code (See Appendix A)
 - Repeat from Col. 18-21 Card 02

VERBAL DESCRIPTION

8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44 45 46 47 48 49 50 51 52 53 54 55 56 57 58 59 60 61 62 63 64 65 66 67 68 69 70 71 72 73 74 75 76 77 78 79 80	0 3 79 30

* IEEE Standard does not recognize transitions to/of Deratings from/to other Event Types
 ** Gross Data Preferred

In order to evaluate prospective improvement projects, the data base must include a detailed description of the events that occurred during past outages. The verbal description on card 02 (columns 48-78) and card 03 (columns 24-78) should be used to fully account for the details of each outage event giving information such as how long was spent waiting for spare parts, delays due to lack of service crews, the size of the service crew, and any other information that would indicate why an outage was delayed or extended. Optionally, a utility may choose to record the verbal detail of an outage on additional data cards for their own use.

Also reported on the ERF card 02 is the time work started on the repair and the time the work was completed. Entered in these columns should be the time the repair crew actually began servicing and the time the repair work was completed and the unit could be returned to power if only this event was occurring. Any delays in making the repair or returning the unit to its gross maximum capacity should be explained in the verbal description on cards 02 and 03 or shown on card 01 by a change in event type (columns 26-45). The man-hours worked on the system/component (columns 44-47 of card 02) should also be completed.

4.3 CONSTRUCTION OF UNIT HYPOTHETICAL DATA

The unit hypothetical data is constructed by considering the impact of the improvement project to be evaluated on the past performance of the unit. In order to determine the impact of the improvement project on past unit events, each event contained in the data that would be altered (eliminated, shortened, fewer lost megawatts, etc.) must be studied in detail. For example, if a pulverizer improvement project is considered, the historical data should be examined for all pulverizer events that would be impacted by the improvement project. Since the GADS Event Report Forms use a primary cause of event system/component cause code (card 02, columns 18-21), this number could be used to retrieve from the historical data various pulverizer events that resulted in plant outages and deratings. Once retrieved, each event should be analyzed to see how the unit would have actually performed had the unit had the improvement project during the event (hypothetical data). This data, along with the historical data (no improvement project), forms the basis for the AIM calculations.

Prior to performing any AIM calculations, the reader should be fully cognizant of the GADS data reporting procedures

(reference 6). With properly entered GADS data for each plant event, an historical data base can be created that allows for most AIM calculations. Based on the GADS data, both the historical and hypothetical operation of the unit can be determined and various plant improvement projects can be evaluated by the methods discussed in this handbook.

5.0 EQUATIONS FOR CALCULATION OF ΔEAF

This section provides a step-by-step listing of the equations that the methodology uses to calculate the change in unit equivalent availability factor that could be achieved by implementing an improvement project at a power plant. The basis of the equations presented in this section is provided in references [1], [2], [3] and [4] and has not been included in this section. Reliability, productivity, and availability terms used in this development are based on recently published IEEE definitions presented in reference [5].

The fundamental equation the methodology uses to evaluate the change in equivalent availability factor from an improvement project is given by:

$$\Delta EAF = -\Delta EUF_F - \Delta EUF_{EE} \quad (1)$$

where

ΔEAF = Change in unit equivalent availability factor following implementation of improvement project

ΔEUF_F = Change in unit equivalent unavailability factor due to component events following implementation of improvement project

ΔEUF_{EE} = Change in unit equivalent unavailability factor due to external/economic events following implementation of improvement project

The remainder of this section is divided into two subsections as follows:

- Subsection 5.1 -- discusses the ΔEUF_F calculation;
- Subsection 5.2 -- discusses the ΔEUF_{EE} calculation.

5.1 ΔEUF_F CALCULATION

The ΔEUF_F in equation (1) is found using the equation:

$$\Delta EUF_F = EUF_F - EUF_{F_{no}} \quad (2)$$

where

EUF_F = Unit equivalent unavailability factor due to component events with improvement project implemented

$EUF_{F_{no}}$ = Unit equivalent unavailability factor due to component events without improvement project implemented

Subsection 5.1 has been divided into two parts labeled:

- ° EUF_F Calculation (5.1.1); and
- ° $EUF_{F_{no}}$ Calculation (5.1.2).

5.1.1 EUF_F Calculation

EUF_F in equation (2) is found by the equation:

$$EUF_F = \left(\frac{em}{eM} \right) \frac{SH}{PH} \times 100 \quad (3)$$

where

em = Equivalent meantime-to-restore when component or system is limiting the unit GAC after improvement project implemented

eM = Equivalent meantime-to-event for system or component after improvement project implemented

SH = Unit service hours with improvement project implemented in time period PH

PH = Period hours

em Calculation

The evaluation of em in equation (3) is found by the equation:

$$em = em_1 + em_2 + em_3 \quad (4)$$

where

em_1 = Equivalent meantime for unit cool-down when component or system is limiting the unit GAC after improvement project implemented

em_2 = Equivalent meantime component service delayed when component or system is limiting the unit GAC after improvement project implemented

em_3 = Equivalent meantime to physically service component by work crew when component or system is limiting the unit GAC after improvement project implemented

The parameters em_1 , em_2 , and em_3 in equation (4) are given by the following equations:

$$em_1 = \frac{\sum_{i=1}^n (UND)_i (m_1)_i}{(n) (GMC)} \quad (5)$$

$$em_2 = \frac{\sum_{i=1}^n (UND)_i (m_2)_i}{(n) (GMC)} \quad (6)$$

$$em_3 = \frac{\sum_{i=1}^n (UND)_i (m_3)_i}{(n) (GMC)} \quad (7)$$

where

n = Number of hypothetical events for given component or system in time period PH

$(UND)_i$ = Unit derating, difference between unit shadowed gross dependable capacity and unit gross available capacity as a result of i th event with improvement project implemented

- GMC = Unit gross maximum capacity
- $(m_1)_i$ = Time for unit cool-down in i^{th} event with improvement project implemented
- $(m_2)_i$ = Time component service delayed in i^{th} event after improvement project implemented
- $(m_3)_i$ = Time to physically service component in i^{th} event after improvement project implemented

The $(m_1)_i$, $(m_2)_i$, and $(m_3)_i$ parameters in equations (5), (6), and (7) are found as follows:

- $(m_1)_i$ Calculation

$(m_1)_i$ data (time for unit cooldown) is determined by estimating the effect of the improvement project on historical event i $(m_{1no})_i$ data. $(m_{1no})_i$ data is recorded on the GADS $(m_{1no})_i$ ERF's cards 02 or 03, under verbal description.

- $(m_2)_i$ Calculation

$(m_2)_i$ data (time for service delay) is determined by estimating the effect of the improvement project on historical event i $(m_{2no})_i$ data. $(m_{2no})_i$ data is recorded on the GADS $(m_{2no})_i$ ERF's cards 02 or 03, under verbal description.

- $(m_3)_i$ Calculation

$$(m_3)_i = \frac{(t_{mh})_i}{(cs)_i} \quad (8)$$

where

n = Number of hypothetical events for given component or system in time period PH

$(t_{mh})_i$ = Man-hours spent to service component in i^{th} hypothetical event. This data is determined by estimating the effect of the improvement project on historical event i $(t_{mh, no})_i$ data.

$(cs)_i$ = Average work crew size during i^{th} hypothetical event. This data is determined by estimating the effect of the improvement project on historical event $(cs_{no})_i$ data.

The $(UND)_i$ parameter in equations (5), (6), and (7) is given by:

$$(UND)_i = GDC_i^* - GAC_i \quad (9)$$

where

GDC_i^* = Shadowed gross dependable capacity, either (a) unit gross dependable capacity in event i if no other concurrent events (excluding noncurtailing events) are occurring in the unit, or (b) the unit gross available capacity as a result of other concurrent events in the unit

GAC_i = Gross available capacity as a result of i^{th} hypothetical event. GAC_i is determined by estimating the effect of the improvement project on $(GAC_{no})_i$ for the i^{th} historical event at the unit. $(GAC_{no})_i$ is read from the GADS ERF's for event i (card 01, columns 54-57).

In applying the $(UND)_i$ calculated from equation (9), $(UND)_i$ is never allowed to be negative. If $GAC_i > GDC_i^*$, then $(UND)_i$ is taken as zero in equations (5), (6), and (7).

If concurrent events occur during event i which have a GAC resulting from their occurrence different than that of event i , $(UND)_i$ can vary over the duration of event i . An example calculation of $(UND)_i$ and the resultant em is given below for this situation.

Example Calculation of $(UND)_i$ and Resultant em

Assume the following:

- Unit-GMC = GDC = 400 MW
- Event no. i starts at 1000 hours and results in a reduction in the unit load to a gross available capacity of 300 MW
- The $(UND)_i$ for this situation with no other event occurring would be calculated as

$$(UND)_i = 400 - 300 = 100 \text{ MW} \quad (10)$$

However, if another event occurs while event no. i is in progress, then $(UND)_i$ has to be further modified. Assume

- While event no. i is in progress, another event -- event no. $i+1$ -- starts at 1400. Event no. $i+1$ acting alone, would result in a reduction in the unit load to a gross available capacity of 350 MW. The $(UND)_i$ during the time event no. i and event no. $i+1$ are acting concurrently (1400 to 1700) would be calculated as

$$(UND)_i = 350 - 300 = 50 \text{ MW} \quad (11)$$

- Further assume --

An event no. $i+2$ starts at 1700 hours, which if acting alone would result in a reduction in the unit load to a gross available capacity of 250 MW.

Since the gross available capacity for event no. $i+2$ acting alone is below the gross available capacity of event no. i , the unit derate for event no. i acting concurrent with event no. $i+2$ becomes zero.

- Finally assume --

Work finished in event no. i at 2000 hours, and event no. i is considered to be completed at this time.

Event nos. $i+1$ and $i+2$ are still assumed to be in progress.

For this complex example, the unit actually had three different derates over the duration of event no. i (Figure 3). The different values of UND_i and their associated duration are shown in Table 2.

Figure 3

TABLE 2	
(UND) _i AND DURATION FOR EVENT NO. i IN EXAMPLE	
Duration	(UND) _i
4 hours	100 MW
3 hours	50 MW
3 hours	0 MW

Using the data in Table 2, an equivalent meantime-to-restore parameter can be computed for the component associated with this one event (n=1) using equations (4) - (7) as follows:

$$em = \frac{100(4) + 50(3) + 0(3)}{(1)(400)} = 1.37 \text{ hours} \quad (12)$$

eM Calculation

The eM calculation in equation (3) has been divided into three cases:

1. Single component systems;
2. Parallel component systems serviceable with unit on-line; and
3. Parallel component systems serviceable only with unit outage.

1. Single Component Systems

For a system consisting of a single component, eM is found by the following equation:

$$eM = M_1 \quad (13)$$

where

M_1 = Meantime-to-event for single component with improvement project implemented.

M_1 in equation (13) is given by the equation:

$$M_1 = r \frac{SH}{n} \quad (14)$$

where

SH = Unit service hours with improvement project implemented in time period PH

n = Number of hypothetical events for given component or system in time period PH

r = Number of components in system required operational for unit to maintain its gross maximum capacity with improvement project implemented. In the single component system, $r = 1$.

2. Parallel Component System Serviceable with Unit On-Line

For a system consisting of parallel components where the system's components are serviceable with the unit on-line, eM is found using the equation:

$$eM = \frac{\sum_{j=r}^{n'} \binom{n'}{j} M_1^j m^{n'-j}}{n' \binom{n'-1}{r-1} M_1^{r-1} m^{n'-r}} \quad (15)$$

where

n' = Total number of parallel components in system with improvement project implemented

r = Number of components required operational for unit to maintain its gross maximum capacity with improvement project implemented

M_1 = Meantime-to-event for single component in system with improvement project implemented

m = Meantime-to-restore single component in system with improvement project implemented

$$\binom{n'}{j} = \frac{n'!}{j! (n'-j)!}$$

$$\binom{n'-1}{r-1} = \frac{(n'-1)!}{(r-1)! (n'-r)!}$$

The parameter M_1 in equation (15) is found using equation (14), while the quantity m in equation (15) is given by:

$$m = \frac{1}{n} \sum_{i=1}^n \left\{ \binom{m_1}{i} + \binom{m_2}{i} + \binom{m_3}{i} \right\} \quad (16)$$

If the data is not available to separately determine $\binom{m_1}{i}$, $\binom{m_2}{i}$, and $\binom{m_3}{i}$, in equation (16), m can be determined as follows:

$$m = \frac{1}{n} \sum_{i=1}^n m_i \quad (17)$$

where

m_i = Duration of hypothetical event i , which is determined by estimating the effect of the improvement project on historical event i $\binom{m_{no}}{i}$ data. $\binom{m_{no}}{i}$ data is determined from GADS ERF's by subtracting the time work completed in event i (card 02, columns 32-39) from start of event time (card 01, columns 18-25).

Table 3 gives formulas for eM for different combinations of systems containing serviceable parallel components using equation (15). Formulas have been developed for systems with total number of components (n') ranging between one (1) and

TABLE 3

EQUIVALENT MEANTIME-TO-EVENT FOR COMPONENTS REPAIRABLE
WITH UNIT ON-LINE

[Equations (15) or (31)]

n' = Total number of parallel components

r = Number of components required for unit to maintain its gross maximum capacity

$n' \backslash r$	1	2	3	4	5	6	7	8	9	10
1	M_1									
2	$M_1 + \frac{M_1^2}{2m}$	$\frac{M_1}{2}$								
3	$M_1 + \frac{M_1^2}{m} + \frac{M_1^3}{3m^2}$	$\frac{M_1}{2} + \frac{M_1^2}{6m}$	$\frac{M_1}{3}$							
4	$M_1 + \frac{3M_1^2}{2m} + \frac{M_1^3}{m^2} + \frac{M_1^4}{4m^3}$	$\frac{M_1^2}{2} + \frac{M_1^2}{3m} + \frac{M_1^3}{12m^2}$	$\frac{M_1}{3} + \frac{M_1^2}{12m}$	$\frac{M_1}{4}$						
5		$\frac{M_1}{2} + \frac{M_1^2}{2m} + \frac{M_1^3}{5m^2} + \frac{M_1^4}{20m^3}$	$\frac{M_1}{3} + \frac{M_1^2}{6m} + \frac{M_1^3}{30m^2}$	$\frac{M_1}{4} + \frac{M_1^2}{20m}$	$\frac{M_1}{5}$					
6			$\frac{M_1}{3} + \frac{M_1^2}{4m} + \frac{M_1^3}{10m^2} + \frac{M_1^4}{60m^3}$	$\frac{M_1}{4} + \frac{M_1^2}{10m} + \frac{M_1^3}{60m^2}$	$\frac{M_1}{5} + \frac{M_1^2}{30m}$	$\frac{M_1}{6}$				
7				$\frac{M_1}{4} + \frac{3M_1^2}{20m} + \frac{M_1^3}{20m^2} + \frac{M_1^4}{140m^3}$	$\frac{M_1}{5} + \frac{M_1^2}{15m} + \frac{M_1^3}{42m^2}$	$\frac{M_1}{6} + \frac{M_1^2}{42m}$	$\frac{M_1}{7}$			
8					$\frac{M_1}{5} + \frac{M_1^2}{10m} + \frac{M_1^3}{35m^2} + \frac{M_1^4}{280m^3}$	$\frac{M_1}{6} + \frac{M_1^2}{21m} + \frac{M_1^3}{168m^2}$	$\frac{M_1}{7} + \frac{M_1^2}{56m}$	$\frac{M_1}{8}$		
9						$\frac{M_1}{6} + \frac{M_1^2}{14m} + \frac{M_1^3}{56m^2} + \frac{M_1^4}{504m^3}$	$\frac{M_1}{7} + \frac{M_1^2}{28m} + \frac{M_1^3}{252m^2}$	$\frac{M_1}{8} + \frac{M_1^2}{72m}$	$\frac{M_1}{9}$	
10							$\frac{M_1}{7} + \frac{3M_1^2}{56m} + \frac{M_1^3}{84m^2} + \frac{M_1^4}{840m^3}$	$\frac{M_1}{8} + \frac{M_1^2}{36m} + \frac{M_1^3}{360m^2}$	$\frac{M_1}{9} + \frac{M_1^2}{90m}$	$\frac{M_1}{10}$

NOTE: When applying Table 3 without unit improvement project implemented, the parameter M_1 should be replaced with M_{1no} ; m with m_{no} ; r with r_{no} ; and n' with n'_{no} .

ten (10), and the number of components required for unit to achieve its gross maximum capacity (r) varying from n'-3 to n', except when n' is less than four (4). When n' is less than four (4), Table 3 includes formulas for values of r ranging from one (1) to n'.

3. Parallel Component System Serviceable only with Unit Outage

For a system consisting of parallel components where the system's components are serviceable only with a unit outage, eM is given by the equation:

$$eM = M_1 \sum_{j=r}^{n'} \frac{(j-1)!}{j!} \quad (18)$$

where

M_1 = Meantime-to-event for single component in system with improvement project implemented. M_1 is found by using equation (14)

n' = Total number of parallel components in system with improvement project implemented

r = Number of components required operational for unit to maintain its gross maximum capacity with improvement project implemented.

Table 4 gives formulas for different combinations of systems with parallel components serviceable only with a unit outage using equation (18). Formulas have been developed for systems with the total number of parallel components (n') ranging between one (1) and ten (10), and the number of components needed for the unit to maintain its gross maximum capacity (r) varying from one (1) to less than, or equal to, n'.

PH and SH Calculation

The period hours (PH) is by definition the same with and without the improvement project implemented. The period hours can be determined from GADS PRF's for the unit by

TABLE 4
EQUIVALENT MEANTIME-TO-EVENT
FOR COMPONENTS REPAIRABLE ONLY WITH UNIT OUTAGE
[Equations (18) or (34)]

n' = Total number of parallel components

r = Number of components required for unit to maintain its gross maximum capacity

$\frac{r}{n'}$	1	2	3	4	5	6	7	8	9	10
1	M_1									
2	$\frac{3}{2} M_1$	$\frac{1}{2} M_1$								
3	$\frac{11}{6} M_1$	$\frac{5}{6} M_1$	$\frac{1}{3} M_1$							
4	$\frac{25}{12} M_1$	$\frac{13}{12} M_1$	$\frac{7}{12} M_1$	$\frac{1}{4} M_1$						
5	$\frac{137}{60} M_1$	$\frac{77}{60} M_1$	$\frac{47}{60} M_1$	$\frac{9}{20} M_1$	$\frac{1}{5} M_1$					
6	$\frac{49}{20} M_1$	$\frac{29}{20} M_1$	$\frac{19}{20} M_1$	$\frac{37}{60} M_1$	$\frac{11}{30} M_1$	$\frac{1}{6} M_1$				
7	$\frac{363}{140} M_1$	$\frac{223}{140} M_1$	$\frac{153}{140} M_1$	$\frac{319}{420} M_1$	$\frac{107}{210} M_1$	$\frac{13}{42} M_1$	$\frac{1}{7} M_1$			
8	$\frac{761}{280} M_1$	$\frac{481}{280} M_1$	$\frac{341}{280} M_1$	$\frac{743}{840} M_1$	$\frac{533}{840} M_1$	$\frac{73}{168} M_1$	$\frac{15}{56} M_1$	$\frac{1}{8} M_1$		
9	$\frac{7129}{2520} M_1$	$\frac{4609}{2520} M_1$	$\frac{3349}{2520} M_1$	$\frac{2509}{2520} M_1$	$\frac{1879}{2520} M_1$	$\frac{275}{504} M_1$	$\frac{191}{504} M_1$	$\frac{119}{504} M_1$	$\frac{1}{9} M_1$	
10	$\frac{7381}{2520} M_1$	$\frac{4861}{2520} M_1$	$\frac{3601}{2520} M_1$	$\frac{2761}{2520} M_1$	$\frac{2131}{2520} M_1$	$\frac{1627}{2520} M_1$	$\frac{1207}{2520} M_1$	$\frac{121}{360} M_1$	$\frac{133}{630} M_1$	$\frac{1}{10} M_1$

NOTE: When applying Table 4, without improvement project implemented, the parameter M_1 should be replaced with M_{1no} ; r with r_{no} ; and n' with n'_{no} .

summing the period hours given on each PRF (card 02, columns 54-57). Usually the PH parameter in equation (3) is determined by the time period over which historical component event data has been collected.

The unit service hours following implementation of the improvement project (SH) is defined as the hours the generation is synchronized following implementation of the improvement project over the time period PH. SH can be found by the equation:

$$SH = SH_{no} + \Delta SH_{no} \quad (19)$$

where

SH_{no} = Historical service hours in time period PH

ΔSH_{no} = Change in unit service hours had improvement project been implemented in unit in time period PH

SH_{no} is given in the GADS PRF (card 02, columns 14-17). It is determined by summing the unit service hours given on each PRF over the time period under study.

ΔSH_{no} is determined by estimating the impact of the improvement project on the unit historical unit service hours. When an improvement project is implemented on a component, which from the historical data collected in the GADS ERF's only resulted in unit derates, then the improvement project will result in no increase in the unit service hours for this type of improvement project. In this situation:

$$\Delta SH = 0 \quad (20)$$

When an improvement project is implemented on a component which has resulted in unit outage hours and the improvement project reduces these outage hours, then the increase in service hours is found as:

$$\Delta SH = \sum_{i=1}^n \text{Nonconcurrent outage hours caused by component with improvement project implemented} - \sum_{i=1}^{n_{no}} \text{Nonconcurrent outage hours caused by component based on historical data} \quad (21)$$

The nonconcurrent outage hours associated with a component are defined as the hours over the given time period that, had the component been returned to service, the unit would become available to produce power.

A component's nonconcurrent outage hours based on historical data can be determined directly from the GADS ERF's . If an event has a U1, U2, U3, or U4 designation for its event type (card 01, columns 16-17) and no other unit event has a U1-U4 designation concurrent with this event, then the component's outage hours are taken to be nonconcurrent.

A component's nonconcurrent outage hours with an improvement project implemented are found by estimating the improvement's effect on the noncurrent outage hours based on the historical GADS data described above.

5.1.2 EU_{Fno} Calculation

EU_{Fno} in equation (2) is found by the equation:

$$EU_{Fno} = \left(\frac{em_{no}}{eM_{no}} \right) \frac{SH_{no}}{PH} \times 100 \quad (22)$$

where

em_{no} = Equivalent meantime-to-restore when component or system is limiting unit GAC before improvement project implemented

eM_{no} = Equivalent meantime-to-event for system or component before improvement project implemented

SH_{no} = Unit service hours without improvement project implemented in time period PH

PH = Period hours

em_{no} Calculation

The evaluation of (em_{no}) in equation (22) is found by the equation:

$$\left(em_{no} \right) = \left(em_{no} \right)_1 + \left(em_{no} \right)_2 + \left(em_{no} \right)_3 \quad (23)$$

where

$$\left(em_{no} \right)_1 = \text{Equivalent meantime for unit cool-down when component or system limiting unit GAC before improvement project implemented}$$

$$\left(em_{no} \right)_2 = \text{Equivalent meantime component service delayed when component or system limiting unit GAC before improvement project implemented}$$

$$\left(em_{no} \right)_3 = \text{Equivalent meantime to physically service component by work crew when component or system limiting unit GAC before improvement project implemented}$$

The parameters $\left(em_{no} \right)_1$, $\left(em_{no} \right)_2$, and $\left(em_{no} \right)_3$ in equation (23) are given by the equations:

$$\left(em_{no} \right)_1 = \frac{\sum_{i=1}^{n_{no}} \left(UND_{no} \right)_i \left(m_{no1} \right)_i}{\left(n_{no} \right) \left(GMC \right)} \quad (24)$$

$$\left(em_{no} \right)_2 = \frac{\sum_{i=1}^{n_{no}} \left(UND_{no} \right)_i \left(m_{no2} \right)_i}{\left(n_{no} \right) \left(GMC \right)} \quad (25)$$

$$\left(em_{no} \right)_3 = \frac{\sum_{i=1}^{n_{no}} \left(UND_{no} \right)_i \left(m_{no3} \right)_i}{\left(n_{no} \right) \left(GMC \right)} \quad (26)$$

where

$$n_{no} = \text{Number of historical events for given component or system in time period PH}$$

$(UND_{no})_i$ = Unit derating in i^{th} event before improvement project implemented

GMC = Gross maximum capacity

$(m_{no1})_i$ = Time for unit cool-down in i^{th} event without improvement project implemented

$(m_{no2})_i$ = Time component service delayed in i^{th} event before improvement project implemented

$(m_{no3})_i$ = Time to physically service component in i^{th} event before improvement project implemented

The $(m_{no1})_i$, $(m_{no2})_i$, and $(m_{no3})_i$ parameters in equations (24), (25), and (26) are found as follows:

- $(m_{no1})_i$ Calculation

$(m_{no1})_i$ data is obtained from the unit historical GADS ERF's for event i (cards 02 or 03, under verbal description)

- $(m_{no2})_i$ Calculation

$(m_{no2})_i$ data is obtained from the unit historical GADS ERF's for event i (cards 02 or 03, under verbal description)

- $(m_{no3})_i$ Calculation

$$(m_{no3})_i = \frac{(t_{mh_{no}})_i}{(cs_{no})_i} \quad (27)$$

$(t_{mh\_no})_i$ = Man-hours spent to service component in i^{th} historical event. This data is read from the GADS ERF for event i (card 02, columns 44-47)

$(cs_{no})_i$ = Average work crew size during i^{th} historical event. This data is read from the GADS ERF's for event i (cards 02 or 03, under verbal description)

The $(UND_{no})_i$ parameter in equations (24), (25), and (26) is given by:

$$(UND_{no})_i = GDC_i^* - (GAC_{no})_i \quad (28)$$

where

GDC_i^* = Shadowed unit gross dependable capacity, either (a) unit gross dependable capacity in event i if no other concurrent events (excluding noncurtailing events) are occurring in the unit, or (b) the unit gross available capacity if concurrent events are occurring at the unit

$(GAC_{no})_i$ = Gross available capacity as result of i^{th} historical event. This data is read from the GADS ERF's for event i (card 01, columns 54-57)

In applying the $(UND_{no})_i$ calculated from equation (28), $(UND_{no})_i$ is never allowed to be negative. If $(GAC_{no})_i > GDC_i^*$, then $(UND_{no})_i$ is taken as zero in equations (24), (25), $(UND_{no})_i$ and (26).

If concurrent events occur during event i which have a GAC resulting from their occurrence different than that of event i , $(UND_{no})_i$ can vary over the duration of event i . The calculation of em_{no} when $(UND_{no})_i$ is not constant over event i follows the same procedure as described in the example calculation of $(UND)_i$, given in section 5.1.1.

eM_{no} Calculation

The parameter eM_{no} in equation (22) depends upon the number of components in the system and whether the components are serviceable with the unit on-line or serviceable only with a unit outage.

• Single Component Systems

For a system consisting of a single component, eM_{no} is found by the equation:

$$eM_{no} = M_{1no} \quad (29)$$

where

M_{1no} = Meantime-to-event for single component without improvement project implemented

M_{1no} in equation (29) is given by the equation:

$$M_{1no} = r_{no} \frac{(SH)_{no}}{n_{no}} \quad (30)$$

where

(SH)_{no} = Unit service hours without improvement project implemented in time period PH

n_{no} = Number of historical events for given component or system in time period PH

r_{no} = Number of components required operational for unit to maintain its gross maximum capacity without improvement project implemented. In the single component system, r_{no} = 1.

• Parallel Component System Serviceable with Unit On-Line

For a system consisting of parallel components where the system's components are serviceable with the unit on-line, eM_{no} is found using the equation:

$$eM_{no} = \frac{\sum_{j=r_{no}}^{n'_{no}} \binom{n'_{no}}{j} M_{1_{no}}^j (m_{no})^{n'_{no}-j}}{n'_{no} \binom{n'_{no}-1}{r_{no}-1} M_{1_{no}}^{(r_{no}-1)} (m_{no})^{(n'_{no}-r_{no})}} \quad (31)$$

where

n'_{no} = Total number of parallel components in system without improvement project implemented

r_{no} = Number of components required operational for unit to maintain its gross maximum capacity without improvement project implemented

$M_{1_{no}}$ = Meantime-to-event for single component in system without improvement project implemented

(m_{no}) = Meantime-to-restore single component in system without improvement project implemented

$$\binom{n'_{no}}{j} = \frac{n'_{no}!}{j! (n'_{no}-j)!}$$

$$\binom{n'_{no}-1}{r_{no}-1} = \frac{(n'_{no}-1)!}{(r_{no}-1)! (n'_{no}-r_{no})!}$$

The parameter $M_{1_{no}}$ in equation (31) is found using equation (30), while the quantity (m_{no}) in equation (31) is given by:

$$(m_{no}) = \frac{1}{n_{no}} \sum_{i=1}^{n_{no}} \left[(m_{no1})_i + (m_{no2})_i + (m_{no3})_i \right] \quad (32)$$

If the data is not available from the GADS ERF's for event i to determine $(m_{no1})_i$, $(m_{no2})_i$, and $(m_{no3})_i$ in equation (32), m_{no} can be determined as follows:

$$m_{no} = \frac{1}{n_{no}} \sum_{i=1}^{n_{no}} (m_{no})_i \quad (33)$$

where

$(m_{no})_i$ is determined from GADS ERF's for event i by subtracting the time work completed in event i (card 02, columns 32-39) from start of event time (card 01, columns 18-25).

Table 3 gives formulas for eM_{no} for different combinations of systems containing serviceable parallel components using equation (31). Formulas have been developed for systems with total number of components (n'_{no}) ranging between one (1) and ten (10) and the number of components required for unit to achieve its gross maximum capacity (r_{no}) varying from $n'_{no}-3$ to n'_{no} , except when n'_{no} is less than four (4). When n'_{no} is less than four (4), Table 3 includes formulas for values of r_{no} ranging from one (1) to n'_{no} .

- Parallel Component Systems Serviceable Only with Unit Outage

For a system consisting of parallel components where the system's components are serviceable only with a unit outage, eM_{no} is given by the equation:

$$eM_{no} = M_{1no} \sum_{j=r_{no}}^{n'_{no}} \frac{(j-1)!}{j!} \quad (34)$$

where

M_{1no} = Meantime-to-event for single component in system without improvement project implemented. M_{1no} is found by using equation (30)

n'_{no} = Total number of parallel components in system without improvement project implemented

r_{no} = Number of components required operational for unit to maintain its gross maximum capacity without improvement project implemented

Table 4 gives formulas for different combinations of systems with parallel components serviceable only with a unit outage using equation (34). Formulas have been developed for systems with the total number of parallel components (n'_{no}) ranging between one (1) and ten (10), and the number of components needed for the unit to maintain its gross maximum capacity (r_{no}) varying from one (1) to less than, or equal to, n'_{no} .

PH and (SH)_{no} Calculation

The time period (PH) is by definition the same with and without the improvement project implemented. Thus, the PH parameter in equation (22) is determined by the time period over which historical GADS component event data has been collected. The time period PH is most easily found by summing up all the time periods given on the GADS PRF's (card 02, columns 54-57).

The unit service hours without implementation of the improvement project (SH)_{no} is defined as the hours the generator is synchronized without implementation of the improvement project over the time period PH. (SH)_{no} can be found by summing up the unit service hours on the GADS PRF's (card 02, columns 14-17) over the time period PH.

5.2 ΔEUF_{EE} CALCULATION

ΔEUF_{EE} in equation (1) is found using the equation:

$$\Delta EUF_{EE} = EUF_{EE} - EUF_{EE_{no}} \quad (35)$$

where

EUF_{EE} = Unit equivalent unavailability factor due to external/economic events with improvement project implemented

$EUF_{EE_{no}}$ = Unit equivalent unavailability factor due to external/economic events without improvement project implemented

Subsection 5.2 has been divided into two parts, labeled:

- ° EUF_{EE} Calculation (5.2.1); and
- ° $EUF_{EE_{no}}$ Calculation (5.2.2).

5.2.1 EUF_{EE} Calculation

EUF_{EE} in equation (35) is found by the equation:

$$EUF_{EE} = \frac{\sum_{i=1}^{n_{EE}} \left[\left((t_{1EE})_i - (t_{0EE})_i \right) (UND_{EE})_i \right]}{(PH) \quad (GMC)} \times 100 \quad (36)$$

where

PH = Period hours

n_{EE} = Number of hypothetical external/economic events

$(t_{1EE})_i$ = Time i^{th} hypothetical external/economic event terminated. This time is determined by estimating the effect of the improvement project on the time historical external/economic event i terminated $(t_{1EEno})_i$.

$(t_{0EE})_i$ = Time i^{th} hypothetical external/economic event initiated. This time is determined by estimating the effect of the improvement project on the time historical external/economic event i initiated $(t_{0EEno})_i$.

GMC = Unit gross maximum capacity

$(UND)_i$ = $GDC^*_i - (GAC_{EE})_i$ (37)

GDC^*_i = Shadowed unit gross dependable capacity, either (a) unit gross dependable capacity in event i if no other concurrent events (excluding noncurtailing events) are occurring in the unit, or (b) the unit gross available capacity if concurrent events are occurring at the unit

$(GAC_{EE})_i$ = Gross available capacity as a result of i^{th} hypothetical external/economic event. $(GAC_{EE})_i$ is determined by estimating the effect of the improvement project on $(GAC_{EEno})_i$ for the i^{th} historical external/economic event.

In applying equation (36), the quantity $(UND_{EE})_i$ is never allowed to be negative. If the $(UND_{EE})_i$ is negative, then it is changed to zero before applying equation (36).

If concurrent events occur during external/economic event i which have a GAC resulting from these events different than that of event i , the $(UND_{EE})_i$ can vary over the duration of event i . An example calculation of EUF_{EE} for this situation is included below.

Example Calculation of $(UND_{EE})_i$

Assume the following:

- Period hours (PH) = 1000 hours
- Unit GMC = GDC = 400 MW
- External/economic event no. i starts at 0800, which results in a reduction in unit load to 250 MW.

The $(UND_{EE})_i$ for this situation is calculated as follows:

$$(UND_{EE})_i = 400 - 250 = 150 \text{ MW} \quad (38)$$

Further assume:

- An event no. i+1 starts at 1300 hours while event no. i is still in progress which, if acting alone, would result in the unit load reduction to a gross available capacity of 350 MW.

The $(UND_{EE})_i$ for the period of time event no. i+1 is acting concurrent with event no. i would be calculated as follows:

$$(UND_{EE})_i = 350 - 250 = 100 \text{ MW} \quad (39)$$

Further assume:

- An event no. i+2 starts at 1900 hours which, if acting alone, would result in a reduction in the unit load to a gross available capacity of 200 MW.

Since the gross available capacity for the time period event no. i+2 and event no. i are acting concurrently is below the gross available capacity as a result of event no. i, the $(UND_{EE})_i$ becomes zero.

Finally assume:

- Event no. i completed at 2200 hours with event nos. i+1 and i+2 still in progress.

For this example, the unit actually had three different derates over the duration of event no. i . The $(UND_{EE})_i$ and the associated duration of each derate are shown in Table 5. The unit gross available capacity versus time for this example is shown in Figure 4.

Figure 4

TABLE 5 $(UND_{EE})_i$ AND DURATION FOR EVENT NO. i IN EXAMPLE	
Duration	$(UND_{EE})_i$
5 hours	150 MW
6 hours	100 MW
3 hours	0 MW

Using the data in Table 5, the $(EUF_{EE})_i$ parameter can be computed for the unit from this single external/economic event ($n_{EE}=1$) using equation (36) as follows:

$$EUF_{EE\ i} = \frac{150(5) + 100(6) + 0(3)}{(1000)(400)} \times 100 = .338\% \quad (40)$$

5.2.2 $EUF_{EE_{no}}$ Calculation

$EUF_{EE_{no}}$ in equation (35) is found by the equation:

$$EUF_{EE_{no}} = \frac{\sum_{i=1}^{n_{EE_{no}}} \left[\left((t_{1EE_{no}})_i - (t_{0EE_{no}})_i \right) (UND_{EE_{no}})_i \right]}{(PH)(GMC)} \times 100 \quad (41)$$

where

PH = Period hours

$n_{EE_{no}}$ = Number of historical external/economic events

$(t_{lEE_{no}})_i$ = Time i^{th} historical external/economic event terminated. This data is recorded on GADS ERF's (card 01, columns 46-53) for event i

$(t_{oEE_{no}})_i$ = Time i^{th} historical external/economic event initiated. This data is recorded on GADS ERF's (card 01, columns 18-25) for event i

$(UND_{EE_{no}})_i$ = $GDC_i^* - (GAC_{EE_{no}})_i$

GDC_i^* = Shadowed unit gross dependable capacity, either (a) unit gross dependable capacity in historical event i if no other concurrent events (excluding noncurtailing events) are occurring at the unit, or (b) the unit gross available capacity if concurrent events are occurring at the unit

$(GAC_{EE_{no}})_i$ = Gross available capacity as a result of i^{th} historical external/economic event i .
 $(GAC_{EE_{no}})_i$ is read from the GADS ERF's for event i (card 01, columns 54-57)

In applying equation (41), the quantity $(UND_{EE_{no}})_i$ is not allowed to become negative. If $(UND_{EE_{no}})_i$ is calculated as negative, then it is changed to zero before applying equation (41).

6.0 EXAMPLES OF THE USE OF THE AIM METHODOLOGY

In order to provide the reader with a better understanding of how the AIM methodology is used, five different examples are worked in detail. Each example illustrates the evaluation of a different improvement project using the equations and methods previously described in this handbook. Specifically, the change in unit equivalent availability factor (ΔEAF) is evaluated for the following examples:

1. The addition of component redundancy in a parallel system;
2. The addition of more reliable components and/or systems;
3. Improved logistics support and spare parts control;
4. Improved maintenance manpower control;
5. Improved preventive maintenance scheduling.

To simplify the analysis, the five examples are all based on the same data which is taken from a fictitious 400 MW coal-fired plant over a period of a month. During the month of operation studied in this example, the unit experienced several power outages from pulverizer and boiler waterwall failures (equipment events). Additionally, the unit underwent several load reductions in order not to exceed stack emissions and other operating environmental limitations (external/economic events). The data is presented on GADS Performance and Event Report Forms. To further the reader's understanding of the operation of the plant and to realize how the data is used in evaluating various improvement projects, a historical gross available generation profile (Figure 14) is developed from the GADS data sheets.

6.1 DISCUSSION OF THE SAMPLE DATA

Section 4.0 of this handbook gives a brief discussion of how equipment failure data and plant data are collected and entered on the various GADS reporting forms. As previously mentioned, the GADS Performance Report Form (PRF) describes the unit's generation performance, starting characteristics, and available and unavailable hours over the reporting period. GADS Event Report Forms (ERF's) are

used to describe various events that result in loss generation due to system/component failures. In addition, these forms are used to indicate changes in the generating status of the unit from such events as reserve shutdown, planned and extended outages, and noncurtailing outages. Prior to performing the calculations described in this section of the handbook, a reader should be fully familiar with the data reporting instructions for the Generating Availability Data System.

6.1.1 Explanation of GADS Performance Report Form

The GADS Performance Report Form (PRF) provides an overall summary of the operating results of a unit. The reporting consists of gross and net actual generation, available and unavailable operating hours, successful and unsuccessful starts, and fuel consumption, quality and type. For the example illustrated in this section of the handbook, the Performance Report Form given in Figure 5 identifies the plant as a base-loaded unit, lists the gross maximum and gross dependable capacity as 400 MWe (i.e., no seasonal derate), shows that one start was attempted, 265,100 gross megawatt hours actual generation, and summarizes the available hours as 694, the unavailable hours as 50, and the period hours as 744. The latter information (i.e., unit time information) is a summary of information contained in the GADS Event Forms for the period of plant operation under consideration.

6.1.2 Explanation of the GADS Event Report Forms

The GADS Event Report Forms (ERF's) provide a detailed summary for each event that results in lost generation due to equipment failures, operational errors, and/or external events. For this example, each event is described on Event Report Forms 1 through 9 in Figures 6 through 14. Included on these forms is a verbal description of delays in servicing resulting from lack of service crews and lack of available spare parts. Additionally, the size of the repair crew is noted to allow for the determination of the actual time spent on the repair (man-hours worked reported on ERF card 02 divided by size of repair crew reported on card 03). This type of information is needed to evaluate the various improvement projects illustrated in this section of the handbook.

UNIT NAME Bayside #4 UTILITY NAME Trident Power Company
REPORTED BY John Doe, Result Engineer PHONE NO (301) 267-8128 DATE 2/1/79

This Performance Report Form may be used for reporting *either* Quarterly or Monthly Performance Data.
(See "Report Period" — Column 11 and 12.)

A—UNIT IDENTIFICATION

Data Card
Code

9	5
1	2

Utility Code

1	0	0
3		5

Unit Code

1	0	0
6		8

Year

7	9
9	10

Report
Period

0	1
11	12

Enter If:
Monthly

01 = Jan.
02 = Feb.
12 = Dec.

Enter if:
Quarterly

X1 = 1/1-3/31
X2 = 4/1-6/30
X3 = 7/1-9/30
X4 = 10/1-12/31

Report
Revision Code

0
13

0-Original Report
1-9-Revisions

B—UNIT GENERATION PERFORMANCE*

Gross Maximum Capacity

0	4	0	0
14			17

Net Maximum Capacity

29			32

Gross Dependable Capacity

0	4	0	0
18			21

Net Dependable Capacity

33			36

Gross (MWhr) Actual Generation

0	2	6	5	1	0	0
22						28

Net (MWhr) Actual Generation

37						43

*Gross Data Preferred
• If Gross unavailable, report Net Data
• If both Gross and Net Data available, report both.

C—UNIT STARTING CHARACTERISTICS

Typical Unit
Loading Characteristics

1
44

- 1—Base Loaded Minor Load-Following
- 2—Periodic Startup Load-Follow Daily Reduced Load Nightly
- 3—Weekly Startup Load-Follow Daily Reduce Load Nightly
- 4—Daily Startup Load-Follow Daily Off-line Nightly
- 5—Startup chiefly to meet Daily Peaks
- 6—Other. Describe in Columns 54-78

Number of

Attempted
Unit Starts

0	0	1
45		47

Actual
Unit Starts

0	0	1
48		50

VERBAL DESCRIPTION (If #6 was used in Column 44)

54																	67
68																	80

0	1
79	80

Figure 5

EVENT REPORT FORM - 1

UNIT NAME Bayside #4 UTILITY NAME Trident Power Company
 REPORTED BY John Doe, Result Engineer PHONE NO (301) 267-8128 DATE 1/2/79

A - EVENT IDENTIFICATION

Data Card Code: 97 Utility Code: 100 Unit Code: 100 Year Event Started: 79

Event Number: 0001 Report Revision Code: 0 Event Type: D1

Event Types:
 P0 - Planned Outage
 SE - Extension of P0 or M0
 U1 - Immediate
 U2 - Delayed
 U3 - Postponed
 PD - Planned Derating
 Unplanned Derating
 D1 - Immediate
 D2 - Delayed
 D3 - Postponed
 D4 - Deferred
 M0 - Maintenance Outage
 RS - Reserve Shutdown
 NC - Non-Curtailing Outage

B - EVENT MAGNITUDE

Start of Event: Month 01 Day 02 Hour 08 Minute 00

Time: Change in Event Type: Month   Day   Hour   Minute   Event Type Changed To:

Time: Change in Event Type: Month   Day   Hour   Minute   Event Type Changed To:

End of Event: Month 01 Day 03 Hour 24 Minute 00

(Report for Deratings Only)
 Gross Available Capacity MWe As Result of Event **: 0300
 Net Available Capacity MWe As Result of Event:

Allowable* Event Type Changes

FROM	TO	P0	SE	U1	U2-U3	M0	RS
P0		yes	yes	no	no	yes	
SE		no	yes	no	no	yes	
U1		yes	no	no	yes	yes	
U2-U3		yes	no	yes	yes	yes	
M0		yes	yes	yes	no	yes	
RS		yes	no	yes	no	yes	

Man Hours Worked on This System/Component: 01

KEY PUNCH - Duplicate Columns 1-17 Card 01

C - PRIMARY CAUSE OF EVENT

System/Component Cause Code (See Appendix A): 0310

Time: Work Started: Month 01 Day 03 Hour 08 Minute 00

Time: Work Completed: Month 01 Day 03 Hour 24 Minute 00

Event Contribution Code: 1 1-Primary Cause of Event

Problem Alert: Enter X only if cause is thought to be generic

Man Hours Worked on This System/Component: 0016

VERBAL DESCRIPTION:
BELT ABROKEN
24 HR DEL NO SER

Man Hours Worked on This System/Component: 02

KEY PUNCH - Duplicate Columns 1-17 Card 01

System/Component Cause Code (See Appendix A)
 - Repeat from Col. 18-21 Card 02

VERBAL DESCRIPTION

0310

VICE CRW 8 HR RE
PAIR DEL LACK SPARE PTS
REPAIR CRW 2 MEN

Man Hours Worked on This System/Component: 03

* IEEE Standard does not recognize transitions to/of Deratings from/to other Event Types

** Gross Data Preferred

Figure 6

EVENT REPORT FORM - 3

UNIT NAME Bayside #4 UTILITY NAME Trident Power Company
 REPORTED BY John Doe, Result Engineer PHONE NO (301) 267-8128 DATE 1/6/79

A - EVENT IDENTIFICATION

Data Card Code: 97 Utility Code: 100 Unit Code: 100 Year Event Started: 79

Event Number: 0003 Report Revision Code: 0 Event Type: D1

0-Original Report
1-9-Revisions

Event Types

P0 - Planned Outage
SE - Extension of P0 or M0
U1 - Immediate
U2 - Delayed
U3 - Postponed

PD - Planned Derating
Unplanned Derating
D1 - Immediate
D2 - Delayed
D3 - Postponed
D4 - Deferred

M0 - Maintenance Outage
RS - Reserve Shutdown
NC - Non-Curtailing Outage

B - EVENT MAGNITUDE

Start of Event: Month 01 Day 06 Hour 12 Minute 00

Time: Change in Event Type: Month   Day   Hour   Minute

Event Type Changed To:

Time: Change in Event Type: Month   Day   Hour   Minute

Event Type Changed To:

End of Event: Month 01 Day 07 Hour 22 Minute 00

(Report for Deratings Only)

Gross Available Capacity MWe As Result of Event **: 0300

Net Available Capacity MWe As Result of Event:

01

FROM	TO	P0	SE	U1	U2-U3	M0	RS
P0			yes	yes	no	no	yes
SE		no		yes	no	no	yes
U1		yes	no		no	yes	yes
U2-U3		yes	no	yes		yes	yes
M0		yes	yes	yes	no		yes
RS		yes	no	yes	no	yes	

KEY PUNCH - Duplicate Columns 1-17 Card 01

C - PRIMARY CAUSE OF EVENT

System/Component Cause Code (See Appendix A): 0300

Time: Work Started: Month 01 Day 06 Hour 12 Minute 00

Time: Work Completed: Month 01 Day 07 Hour 22 Minute 00

Event Contribution Code: 1 1-Primary Cause of Event

Problem Alert: Enter X only if cause is thought to be generic

Man Hours Worked on This System/Component: 0006

VERBAL DESCRIPTION

MOTOR A INSULAT ION FAIL, MAT'L

02

KEY PUNCH - Duplicate Columns 1-17 Card 01

System/Component Cause Code (See Appendix A)

- Repeat from Col. 18-21 Card 02

VERBAL DESCRIPTION

0300

DEFECT, REPAIR C

REW 1 MAN, PART DELAY = 28

HRS

03

* IEEE Standard does not recognize transitions to/of Deratings from/to other Event Types

** Gross Data Preferred

Figure 8

EVENT REPORT FORM - 4

UNIT NAME Bayside #4 UTILITY NAME Trident Power Company
 REPORTED BY John Doe, Result Engineer PHONE NO (301) 267-8128 DATE 1/6/79

A - EVENT IDENTIFICATION

Data Card Code 9 7	Utility Code 1 0 0	Unit Code 1 0 0	Year Event Started 7 9	Event Types P0—Planned Outage SE—Extension of P0 or M0 U1—Immediate U2—Delayed U3—Postponed P0—Planned Derating SE—Unplanned Derating D1—Immediate D2—Delayed D3—Postponed D4—Deferred M0—Maintenance Outage RS—Reserve Shutdown NC—Non-Curtailing Outage
Event Number 0 0 0 4	Report Revision Code 0 0—Original Report 1-9—Revisions	Event Type D 1		

B - EVENT MAGNITUDE

Start of Event Month Day Hour Minute 0 1 0 6 1 8 0 0	Time: Change in Event Type Month Day Hour Minute [ ] [ ] [ ] [ ]	Event Type Changed To: [ ] [ ]	Allowable* Event Type Changes <table border="1"> <thead> <tr> <th>TO</th> <th>P0</th> <th>SE</th> <th>U1</th> <th>U2-U3</th> <th>M0</th> <th>RS</th> </tr> </thead> <tbody> <tr> <td>FROM P0</td> <td></td> <td>yes</td> <td>yes</td> <td>no</td> <td>no</td> <td>yes</td> </tr> <tr> <td>SE</td> <td>no</td> <td></td> <td>yes</td> <td>no</td> <td>no</td> <td>yes</td> </tr> <tr> <td>U1</td> <td>yes</td> <td>no</td> <td></td> <td>no</td> <td>yes</td> <td>yes</td> </tr> <tr> <td>U2-U3</td> <td>yes</td> <td>no</td> <td>yes</td> <td></td> <td>yes</td> <td>yes</td> </tr> <tr> <td>M0</td> <td>yes</td> <td>yes</td> <td>yes</td> <td>no</td> <td></td> <td>yes</td> </tr> <tr> <td>RS</td> <td>yes</td> <td>no</td> <td>yes</td> <td>no</td> <td>yes</td> <td></td> </tr> </tbody> </table>	TO	P0	SE	U1	U2-U3	M0	RS	FROM P0		yes	yes	no	no	yes	SE	no		yes	no	no	yes	U1	yes	no		no	yes	yes	U2-U3	yes	no	yes		yes	yes	M0	yes	yes	yes	no		yes	RS	yes	no	yes	no	yes	
TO	P0	SE		U1	U2-U3	M0	RS																																													
FROM P0		yes	yes	no	no	yes																																														
SE	no		yes	no	no	yes																																														
U1	yes	no		no	yes	yes																																														
U2-U3	yes	no	yes		yes	yes																																														
M0	yes	yes	yes	no		yes																																														
RS	yes	no	yes	no	yes																																															
Time: Change in Event Type Month Day Hour Minute [ ] [ ] [ ] [ ]	Event Type Changed To: [ ] [ ]	End of Event Month Day Hour Minute 0 1 0 7 1 3 0 0																																																		

(Report for Deratings Only)

Gross Available Capacity MWe As Result of Event ** 0 3 0 0	Net Available Capacity MWe As Result of Event [ ] [ ] [ ] [ ]	[ ] [ ]

KEY PUNCH - Duplicate Columns 1-17 Card 01

C - PRIMARY CAUSE OF EVENT

System/Component Cause Code (See Appendix A) 0 3 0 0 [X] [X]	Time: Work Started Month Day Hour Minute 0 1 0 7 0 8 0 0	Time: Work Completed Month Day Hour Minute 0 1 0 7 1 3 0 0	[X] [X]
Event Contribution Code 1 1—Primary Cause of Event	Problem Alert [ ] Enter X only if cause is thought to be generic	Man Hours Worked on This System/Component 0 0 1 0	
VERBAL DESCRIPTION M O T O R C F I R E 1 4 H R D E L A Y L A C K S E			

KEY PUNCH - Duplicate Columns 1-17 Card 01

System/Component Cause Code (See Appendix A) — Repeat from Col. 18-21 Card 02 0 3 0 0 [X] [X]	VERBAL DESCRIPTION R V I C E C R E W R E P A I R C R E W 2 M E N

* IEEE Standard does not recognize transitions to/of Deratings from/to other Event Types
 ** Gross Data Preferred

EVENT REPORT FORM - 5

UNIT NAME Bayside #4
 REPORTED BY John Doe, Result Engineer

UTILITY NAME Trident Power Company
 PHONE NO (301) 267-8128 DATE 1/7/79

A - EVENT IDENTIFICATION

Data Card
Code

9 7

Utility Code

1 0 0

Unit Code

1 0 0

Year Event
Started

7 9

Event Number

0 0 0 5

Report Revision Code

0

0-Original Report
1-9-Revisions

Event Type

D 1

Event Types

P0 - Planned Outage
 SE - Extension of P0 or M0
 U1 - Immediate
 U2 - Delayed
 U3 - Postponed
 M0 - Maintenance Outage
 RS - Reserve Shutdown
 NC - Non-Curtailing Outage
 PD - Planned Derating
 Unplanned Derating
 D1 - Immediate
 D2 - Delayed
 D3 - Postponed
 D4 - Deferred

B - EVENT MAGNITUDE

Start of Event

Month Day Hour Minute
 0 1 0 7 1 3 0 0

Time: Change in Event Type

Month Day Hour Minute
 [ ] [ ] [ ] [ ] [ ] [ ] [ ] [ ]

Event Type
Changed To:

[ ] [ ]

Allowable* Event Type Changes

FROM	TO	P0	SE	U1	U2-U3	M0	RS
P0			yes	yes	no	no	yes
SE		no		yes	no	no	yes
U1		yes	no		no	yes	yes
U2-U3		yes	no	yes		yes	yes
M0		yes	yes	yes	no		yes
RS		yes	no	yes	no	yes	

Time: Change in Event Type

Month Day Hour Minute
 [ ] [ ] [ ] [ ] [ ] [ ] [ ] [ ]

Event Type
Changed To:

[ ] [ ]

End of Event

Month Day Hour Minute
 0 1 0 8 0 8 0 0

(Report for Deratings Only)

Gross Available Capacity MWe
As Result of Event **

0 2 0 0

Net Available Capacity MWe
As Result of Event

[ ] [ ] [ ] [ ] [ ] [ ] [ ] [ ]

0 1

KEY PUNCH - Duplicate Columns 1-17 Card 01

C - PRIMARY CAUSE OF EVENT

System/Component Cause Code
(See Appendix A)

9 6 0 0 [X] [X]

Time: Work Started

Month Day Hour Minute
 [ ] [ ] [ ] [ ] [ ] [ ] [ ] [ ]

Time: Work Completed

Month Day Hour Minute
 [ ] [ ] [ ] [ ] [ ] [ ] [ ] [ ]

[X] [X]

Event Contribution Code

1 1-Primary Cause of Event

Problem Alert

[ ] Enter X only if cause is
thought to be generic

Man Hours Worked on
This System/Component

[ ] [ ] [ ] [ ] [ ] [ ] [ ] [ ]

VERBAL DESCRIPTION

P O O R C O A L Q U A L I

T Y R E L A T E D

0 2

KEY PUNCH - Duplicate Columns 1-17 Card 01

System/Component Cause Code (See Appendix A)

- Repeat from Col. 18-21 Card 02

VERBAL DESCRIPTION

[ ] [ ] [ ] [ ] [ ] [ ] [ ] [ ]

[ ] [ ] [ ] [ ] [ ] [ ] [ ] [ ]

[ ] [ ] [ ] [ ] [ ] [ ] [ ] [ ]

0 3

* IEEE Standard does not recognize transitions to/of Deratings from/to other Event Types

** Gross Data Preferred

EVENT REPORT FORM - 6

UNIT NAME Bayside #4 UTILITY NAME Trident Power Company
 REPORTED BY John Doe, Result Engineer PHONE NO (301) 267-8128 DATE 1/12/79

A - EVENT IDENTIFICATION

Data Card Code: 97 Utility Code: 100 Unit Code: 100 Year Event Started: 79

Event Number: 0006 Report Revision Code: 0 Event Type: D1

0-Original Report
1-9-Revisions

Event Types:
 P0 - Planned Outage
 SE - Extension of P0 or M0
 U1 - Immediate
 U2 - Delayed
 U3 - Postponed
 PD - Planned Derating
 U - Unplanned Derating
 D1 - Immediate
 D2 - Delayed
 D3 - Postponed
 D4 - Deferred
 M0 - Maintenance Outage
 RS - Reserve Shutdown
 NC - Non-Curtailing Outage

B - EVENT MAGNITUDE

Start of Event: Month 01 Day 12 Hour 10 Minute 00

Time: Change in Event Type: Month   Day   Hour   Minute   Event Type Changed To:

Time: Change in Event Type: Month   Day   Hour   Minute   Event Type Changed To:

End of Event: Month 01 Day 14 Hour 12 Minute 00

(Report for Deratings Only)

Gross Available Capacity MWe As Result of Event **: 0000

Net Available Capacity MWe As Result of Event:

Allowable* Event Type Changes

FROM \ TO	P0	SE	U1	U2-U3	M0	RS
P0		yes	yes	no	no	yes
SE	no		yes	no	no	yes
U1	yes	no		no	yes	yes
U2-U3	yes	no	yes		yes	yes
M0	yes	yes	yes	no		yes
RS	yes	no	yes	no	yes	

KEY PUNCH - Duplicate Columns 1-17 Card 01

C - PRIMARY CAUSE OF EVENT

System/Component Cause Code (See Appendix A): 1000

Time: Work Started: Month 01 Day 13 Hour 08 Minute 00

Time: Work Completed: Month 01 Day 14 Hour 12 Minute 00

Event Contribution Code: 1 1-Primary Cause of Event

Problem Alert: ☐ Enter X only if cause is thought to be generic

Man Hours Worked on This System/Component: 0112

VERBAL DESCRIPTION: EROSION CRACK

10 HR SERVICE DE

KEY PUNCH - Duplicate Columns 1-17 Card 01

System/Component Cause Code (See Appendix A)

- Repeat from Col. 18-21 Card 02

VERBAL DESCRIPTION

1000

LAY LACK OF CREW

REPAIR CREW SIZE 4 MEN

12 HR COOLDOWN

03

* IEEE Standard does not recognize transitions to/of Deratings from/to other Event Types

** Gross Data Preferred

Figure 11

EVENT REPORT FORM - 8

UNIT NAME Bayside #4 UTILITY NAME Trident Power Company
 REPORTED BY John Doe, Result Engineer PHONE NO (301) 267-8128 DATE 1/14/79

A - EVENT IDENTIFICATION

Data Card Code: 97 Utility Code: 100 Unit Code: 100 Year Event Started: 79

Event Number: 0008 Report Revision Code: 0 Event Type: D1

0-Original Report
1-9-Revisions

Event Types:
 P0 - Planned Outage
 SE - Extension of P0 or M0
 U1 - Immediate
 U2 - Delayed
 U3 - Postponed
 PD - Planned Derating
 Unplanned Derating
 D1 - Immediate
 D2 - Delayed
 D3 - Postponed
 D4 - Deferred
 M0 - Maintenance Outage
 RS - Reserve Shutdown
 NC - Non-Curtailing Outage

B - EVENT MAGNITUDE

Start of Event: Month 01 Day 14 Hour 12 Minute 00

Time: Change in Event Type: Month   Day   Hour   Minute

Event Type Changed To:

Time: Change in Event Type: Month   Day   Hour   Minute

Event Type Changed To:

End of Event: Month 01 Day 15 Hour 19 Minute 00

(Report for Deratings Only)

Gross Available Capacity MWe As Result of Event **: 0300

Net Available Capacity MWe As Result of Event:

Allowable* Event Type Changes

TO	P0	SE	U1	U2-U3	M0	RS
FROM P0		yes	yes	no	no	yes
SE	no		yes	no	no	yes
U1	yes	no		no	yes	yes
U2-U3	yes	no	yes		yes	yes
M0	yes	yes	yes	no		yes
RS	yes	no	yes	no	yes	

KEY PUNCH - Duplicate Columns 1-17 Card 01

C - PRIMARY CAUSE OF EVENT

System/Component Cause Code (See Appendix A): 0310

Time: Work Started: Month 01 Day 15 Hour 09 Minute 00

Time: Work Completed: Month 01 Day 15 Hour 19 Minute 00

Event Contribution Code: 1 1-Primary Cause of Event

Problem Alert: Enter X only if cause is thought to be generic

Man Hours Worked on This System/Component: 0012

VERBAL DESCRIPTION: BELT C BREAK 21
HR SERVICE DELAY

KEY PUNCH - Duplicate Columns 1-17 Card 01

System/Component Cause Code (See Appendix A)

- Repeat from Col. 18-21 Card 02

VERBAL DESCRIPTION

0310 LACK WORK CREW
6 HR DELAY LACK PARTS
REP CREW 3 MEN

* IEEE Standard does not recognize transitions to/of Deratings from/to other Event Types

** Gross Data Preferred

Figure 13

6.1.2.1 Event Number 1 (GADS Event Report Form-1)

The first event described on the GADS Event Report Form-1 (ERF-1), shown in Figure 6, is a belt failure in the "A" pulverizer (ERF-1, card 02) resulting in a plant derate to 300 MW (ERF-1, card 01). This event is initiated on 1/2/79 at 0800 (card 01). As explained on cards 02 and 03, the servicing of the pulverizer is not initiated until 1/3/79 at 0800 -- a 24-hour delay due to lack of a service crew. The average crew size making the repair is two, working 16 man-hours to make the repair.

The combination of man-hours worked on the component (16 hours) and the size of the repair crew (2 men) indicate the repair was made in eight hours, but the component service was not completed until 1/3/79 - 2400 (card 02) -- 16 hours after the service was initiated. The 8-hour delay in servicing is described on card 03 and is attributed to the lack of spare parts. Servicing of the pulverizer is completed on 1/3/79 at 2400 (card 02), at which time this event is considered ended.

6.1.2.2 Event Number 2 (ERF-2)

The second event is described on ERF-2, shown in Figure 7. Prior to completing the pulverizer repair described in ERF-1, the unit has its power limited to 325 MW (ERF-2, card 01) in order to meet SO₂ stack emission limitations (card 02). This restriction starts at 1/3/79 at 2000 and is lifted on 1/4/79 at 0800 (card 01), at which time the unit has its gross available capacity increased to its gross maximum capacity of 400 MW.

6.1.2.3 Event Number 3 (ERF-3)

The third event is a motor failure in the "A" pulverizer (ERF-3, card 02), shown in Figure 8, occurring on 1/6/79 - 1200 and resulting in the load again being reduced to 300 MW (card 01). Servicing begins immediately (card 02). Although it takes only six man-hours to physically make the repair (cards 02 and 03), the servicing is not completed until 1/7/79 - 2200 due to lack of spare parts (cards 02 and 03).

6.1.2.4 Event Number 4 (ERF-4)

During the servicing of the motor of "A" pulverizer (event no. 3 reported on ERF-3), "C" pulverizer also experiences a motor failure on 1/6/79 at 1800 (ERF-4, card 01), as shown in Figure 9. The unit gross available capacity as a result of this event is 300 MW (card 01). This event combined with event no. 2 actually limits the unit to 200 MW, but the GADS data is reported as if event no. 4 is acting as an independent plant event. Servicing is not initiated until 1/7/79 - 0800 (card 02) -- 14 hours after the event began due to lack of a work crew. Servicing takes five hours, making the component ready for operation on 1/7/79 at 1300 hours (card 02). Noting the times of this event, it is seen that this event overlaps with event no. 3, the motor failure in "A" pulverizer.

6.1.2.5 Event Number 5 (ERF-5)

At the completion of the repair to "C" pulverizer on 1/7/79 - 1300, the unit could be increased in power from 200 to 300 MW. However, as described on ERF-5 (Figure 10, the unit is limited to 200 MW from 1/7/79 - 1300 to 1/8/79 - 0800 (card 01) in order to meet SO₂ stack emission limitations (card 02). At the completion of this event, 1/8/79 - 0800, the unit is returned to its full 400 MW gross maximum capacity.

6.1.2.6 Event Number 6 (ERF-6)

Event no. 6, described on Figure 11, consists of a waterwall tube failure in a boiler causing the plant to come off line. This event is initiated on 1/12/79 at 1000 hours (card 01) and necessitates a 12-hour cool-down prior to initiating service. Although servicing could begin on 1/12/79 at 2200, it is not begun until 1/13/79 - 0800 (card 02) due to a 10-hour delay because of the lack of a work crew (cards 02 and 03). Servicing is completed in 28 hours at 1/14/79 - 1200 (card 02) at which time the unit is synchronized.

6.1.2.7 Event Number 7 (ERF-7)

During the boiler tube failure, the "A" pulverizer, as shown in Figure 12 is taken out of service on 1/12/79 - 1200 hours

(ERF-7, card 01) to repair the rollers. Servicing is initiated immediately and completed in four hours by a repair crew of two men working eight man-hours (card 02). The pulverizer is returned to service on 1/12/79 at 1600 hours. The gross available capacity resulting from this piece of equipment being out of service is reported as 300 MW (card 01) as this is the reduced output for this type of failure. However, the unit is actually at zero power due to the continuing boiler tube failure (ERF-6).

6.1.2.8 Event Number 8 (ERF-8)

On 1/14/79 - 1200 as the unit is being loaded from the boiler tube failure, the belt "C" pulverizer fails, resulting in the gross available capacity being limited to 300 MW (ERF-8, card 01), as described in Figure 13. Start of servicing is delayed 21 hours until 1/15/79 - 0900 due to lack of a work crew (cards 02 and 03). Although servicing takes only four hours (cards 02 and 03), it is not completed until 1/15/79 - 1900 (card 02) due to a 6-hour delay for lack of spare parts.

6.1.2.9 Event Number 9 (ERF-9)

Concurrent with event no. 8, described on ERF-8, is a reduction in power due to thermal limits (ERF-9), shown on Figure 14. This reduction in power starts on 1/15/79 - 1600 and lasts until 1/16/79 - 0700, at which time the unit is returned to its gross maximum capacity of 400 MW and runs at 400 MW for the remainder of the month.

6.1.3 Summary of the Event Report Forms

Table 6 shows a summary of the GADS outage data for the nine events that are used in the following examples. It is not necessary to prepare this table in doing the AIM calculations that follow. It is included only to add further insight in developing both the historical and hypothetical unavailability parameters and in preparing the historical and hypothetical unit power profiles.

TABLE 6

CHRONOLOGICAL BREAKDOWN OF EXAMPLE OUTAGE DATA

EVENT NO. (ERF'S)	CAUSE OF EVENT	MAJOR ELEMENTS OF EVENT DURATION	START TIME	END TIME	HOURS	GROSS AVAILABLE CAPACITY AS A RESULT OF EVENT
1	Pulverizer mill "A" belt failure	Service delay	1/2/79 0800	1/3/79 0800	24	300 MW
		Parts delay	1/3/79 0800	1/3/79 1600	8	300 MW
		Repair	1/3/79 1600	1/3/79 2400	8 <u>40</u>	300 MW
2	SO ₂ stack emission derate	External/economic outage	1/3/79 2000	1/4/79 0800	12	325 MW
3	Pulverizer mill "A" motor failure	Parts delay	1/6/79 1200	1/7/79 1600	28	300 MW
		Repair	1/7/79 1600	1/7/79 2200	6 <u>34</u>	300 MW
4	Pulverizer mill "C" motor failure	Service delay	1/6/79 1800	1/7/79 0800	14	300 MW
		Repair	1/7/79 0800	1/7/79 1300	5 <u>19</u>	300 MW
5	SO ₂ stack emission derate	External/economic outage	1/7/79 1300	1/8/79 0800	19	200 MW
6	Boiler tube leak	Cooldown	1/12/79 1000	1/12/79 2200	12	0 MW
		Service delay	1/12/79 2200	1/13/79 0800	10	0 MW
		Repair	1/13/79 0800	1/14/79 1200	28 <u>50</u>	0 MW
7	Pulverizer mill "A" roller	Repair	1/12/79 1200	1/12/79 1600	4	300 MW
8	Pulverizer mill "C" belt failure	Service delay	1/14/79 1200	1/15/79 0900	21	300 MW
		Parts delay	1/15/79 0900	1/15/79 1500	6	300 MW
		Repair	1/15/79 1500	1/15/79 1900	4 <u>31</u>	300 MW
9	Thermal limit derate	External/economic outage	1/15/79 1600	1/16/79 0700	15	300 MW

6.1.4 Construction of the Unit Historical GAG Profile

From the data given in Event Report Forms 1 through 9, a complete GAG profile for the unit can be constructed as shown in Figure 15. This figure accurately describes the operation of the plant over the one-month period 1/1/79 to 1/31/79 used for this example. Each event is shown on this figure, both by number and the time it occurred and ended. As specified by GADS instructions, outages and reserve shutdowns end with the synchronization of the unit to the system, except when a change in event type occurs. For the example given, no changes in event types are reported. In this example, the deratings are ended when the work to repair the equipment is completed (card 02, columns 32-39). Should the unit not be returned to its 400 MW gross maximum capacity at this time, either another event has begun or a concurrent event is continuing to keep the unit at a reduced power level.

The construction of Figure 15 - Unit Historical GAG Profile is not needed for performing the evaluations of improvement projects described in this handbook. It is shown only to allow a greater understanding of the data and events that are used in the examples presented in following sections. Additionally, the unit historical GAG profile can be used to fill out card 02 (Unit Time Information) of the Performance Report Form.

UNIT HISTORICAL GROSS AVAILABLE GENERATION (GAG) PROFILE

Figure 15

6.2 CALCULATION OF HISTORICAL UNIT EQUIVALENT UNAVAILABILITY FACTOR DUE TO PULVERIZERS

In sections 6.3 through 6.7, five examples are presented to illustrate the methodology's approach for evaluating various types of improvement projects with the unit's pulverizer mills. Common to each project is the component and external/economic equivalent unavailability factors prior to implementation of the improvement project. This section describes the calculation of $EUF_{F_{no}}$ and $EUF_{EE_{no}}$ using the data shown in GADS Event Report Forms 1-9 and the GADS Performance Report Form.

In addition to the GADS data, the following general type of information describing the pulverizer mills is necessary to evaluate the various improvement projects illustrated in the following sections:

- ° Number of parallel pulverizer mills = 4
- ° Number needed to achieve gross maximum capacity = 4
- ° Pulverizer mills are serviceable with the unit on-line
- ° Unit gross maximum capacity if
  - 1 pulverizer mill out of service = 300 MW
  - 2 pulverizer mills out of service = 200 MW
  - 3 pulverizer mills out of service = 100 MW
  - 4 pulverizer mills out of service = 0 MW
- ° Unit experiences no seasonal derates. Consequently, the GMC equals GDC for the unit.

This data is usually available from plant operating personnel and from plant design information and is used in the AIM methodology to establish how the unit performs after improvement projects are undertaken.

6.2.1 $EUF_{F_{no}}$ Calculation

Equation (22) in section 5.1.2 shows that:

$$EUF_{F_{no}} = \left(\frac{em_{no}}{eM_{no}} \right) \frac{SH_{no}}{PH} \times 100 \quad (22)$$

where

$EUF_{F_{no}}$ = Equivalent unavailability factor due to pulverizer mill events with no improvement project using data in ERF's 1-9

em_{no} = Equivalent meantime-to-restore when pulverizer mills controlling unit GAC with no improvement project based on data in ERF's 1-9

eM_{no} = Equivalent meantime-to-event for pulverizer mills with no improvement project based on data in ERF's 1-9

SH_{no} = Unit service hours based on historical data (i.e., no improvement project) in the GADS Performance Report Form (PRF)

PH = Period hours given in the PRF

Since the event data used in this analysis covers the month of January (which has 31 days), the period hours are given by:

$$PH = 31 \text{ days} \times \frac{24 \text{ hours}}{\text{day}} = 744 \text{ hours} \quad (42)$$

During this time period, the unit failed to have its generator synchronized for 50 hours -- as shown on the Performance Report Form. Consequently, the unit service hours can be calculated as:

$$SH_{no} = 744 - 50 = 694 \text{ hours} \quad (43)$$

The parameter em_{no} in equation (22) is determined by adding equations (24) through (26) in section 5.1.2 together, which gives:

$$em_{no} = \frac{\sum_{i=1}^{n_{no}} (UND_{no})_i (m_{no})_i}{(n_{no}) (GMC)} \quad (44)$$

where

n_{no} = 5, number of historical events for pulverizer mills (ERF's 1, 3, 4, 7, and 8)

$(UND_{no})_i$ = Unit derating in i th historical event

$(m_{no})_i$ = $(m_{no1} + m_{no2} + m_{no3})$, duration of i th event

Table 7 gives values of $(UND_{no})_i$ and $(m_{no})_i$ for the five events listed on ERF's 1, 3, 4, 7, and 8 that resulted from pulverizer failures.

Event no. 1 shown in Table 7 has been broken into two parts. The first part of event no. 1 is a nonconcurrent event and lasts for 36 hours (0800 - 1/2/79 to 2000 - 1/3/79). The unit derating is 100 MW during this time period. From 2000 - 1/3/79 to 2400 - 1/3/79, event no. 1 overlaps with external/economic event no. 2. Since event no. 2 (if acting alone) would limit the unit to 325 MW, the unit derating charged to event no. 1 is the difference between these events or 25 MW. If event no. 2 had resulted in a larger derate than 100 MW, then the event no. 1 UND during this 4-hour time period would have been reduced to zero.

The outage duration for event no. 3 in Table 6 is affected by overlapping external/economic event no. 5. The time duration of event no. 3 can be broken into two parts as was done for event no. 1. The first part of event no. 3 extends from the start of event no. 3 (1200 - 1/6/79) to the start of event no. 5 (1300 - 1/7/79), during which the unit is derated 100 MW. The second part of event no. 3 extends from the start of event no. 5 to the end of event no. 3 (2200 - 1/7/79). Since event no. 5 results in a greater unit derate than event no. 3, the unit derate during this latter period is taken to be zero.

TABLE 7 VALUES OF $(UND_{no})_i$ AND $(m_{no})_i$ FOR PULVERIZER MILL EVENTS LISTED ON ERF'S		
Event i	$(UND_{no})_i$ (MW)	$(m_{no})_i$ (Hours)
1	100	36
1	25	4
3	100	25
3	0	9
4	100	19
7	0	4
8	100	28
8	0	3

Event no. 4, which also overlaps event no. 3, doesn't limit the event no. 3 unit derate (UND_3) since it is also a pulverizer mill event whose derate effect is directly additive to that of event no. 3. If event no. 4 had been a nonadditive pulverizer mill unit derate, then UND_3 would have to be modified for the time period after which event no. 4 starts. A nonadditive unit derate is defined to occur if the sum of the derates caused by multiple component events doesn't equal the total derate the unit undergoes.

The event no. 4 outage duration is found by taking the difference between the time event no. 4 starts (1800 - 1/6/79) to when event no. 4 terminates (1300 - 1/7/79). The unit is derated 100 MW as a result of this event during this time period.

Event no. 7 which lasts for four hours, from 1200 - 1/12/79 to 1600 - 1/12/79, is entirely shadowed by event no. 6 -- a waterwall tube leak repair. Consequently, the UND assigned to this event is zero.

Event no. 8, which starts at 1200 - 1/14/79, controls the unit load until external/economic event no. 9 begins at 1600 - 1/15/79. Consequently, the outage duration over which the unit derating is 100 MW is 28 hours. The final three hours of event no. 8 results in no unit derating because event no. 8 and event no. 9 both limit the unit load to 300 MW.

Putting the values of $(UND_{no})_i$ and $(m_{no})_i$ in Table 7 into equation (44), along with the value of n_{no} and the unit GMC, gives:

$$\begin{aligned}
 em_{no} &= \frac{(100)(36) + (25)(4) + (100)(25) + (0)(9) + (100)(19) + (0)(4) + (100)(28) + (0)(8)}{(5)(400)} \\
 &= 5.45 \text{ hours} \quad (45)
 \end{aligned}$$

Because the pulverizer mills in the unit are repairable with the unit on-line, eM_{no} in equation (22) is found by using the formulas given in Table 3, section 5.1.1. If the pulverizer mills had not been repairable with the unit on-line, the eM_{no} would have been found using the formulas given in Table 4 of section 5.1.1. Since the unit has four pulverizer mills (section 6.2) and four are required for the unit to achieve gross dependable capacity, Table 4 is entered with values of $r_{no} = n_{no} = 4$. Therefore, eM_{no} is given by:

$$eM_{no} = \frac{M_{l_{no}}}{4} \quad (46)$$

where

$M_{1_{no}}$ = The meantime-to-event for a single component without improvement project implemented, which is found from equation (29) in section 5.1.2.

This equation is repeated below for convenience:

$$M_{1_{no}} = r_{no} \frac{SH_{no}}{n_{no}} \quad (29)$$

where

r_{no} = 4; number of pulverizer mills required operational for unit to maintain its GMC

SH_{no} = 694 hours calculated from equation (43); number of service hours in time period (month of January)

n_{no} = 5; number of pulverizer events in time period (month of January)

Putting the values of r_{no} , SH_{no} , and n_{no} into equation (29) gives:

$$M_{1_{no}} = \frac{(4) (694)}{5} = 555.2 \text{ hours} \quad (47)$$

Inserting the values of $M_{1_{no}}$ found in equation (47) into equation (46) gives:

$$eM_{no} = \frac{555.2}{4} = 138.8 \text{ hours} \quad (48)$$

Finally, putting the results of equations (42), (43), (45), and (48) into equation (22) gives:

$$EUF_{F_{no}} = \frac{5.45}{138.8} \left(\frac{694}{744} \right) \times 100 = 3.66 \% \quad (49)$$

Equation (49) implies that if all the pulverizer mill events could be eliminated at the unit, the unit equivalent availability factor would be increased by 3.66% or physically that the unit would produce 13.35 more full power days of energy per year. The exact equivalent availability factor increase the unit will obtain depends on the particular improvement project and how it affects both the pulverizer mill events as well as the other concurrent events. This calculation is described for five improvement projects in sections 6.3 through 6.7.

6.3   EXAMPLE 1:   EFFECT ON UNIT EQUIVALENT AVAILABILITY   FACTOR OF ADDITIONAL COMPONENT REDUNDANCY   IN SYSTEMS WITH PARALLEL COMPONENTS

Define Improvement Project

The data listed previously in section 6.2 shows the unit contains four pulverizer mills with all four needed in operation for the unit to achieve its gross maximum capacity (400 MW). The improvement project evaluated in this section is the addition of a fifth pulverizer in the unit. Since all the pulverizer events have been attributed to problems with the pulverizer mills, this improvement project will predict the future ΔEAF of the unit if it operates with five pulverizer mills.

Develop Assumptions of Improvement Project Effect on Unit Historical Data

The following assumptions are made regarding the impact of the fifth pulverizer on the unit's historical pulverizer mill event data in order to construct corresponding hypothetical data.

1. Unit gross available capacity for future operation with the fifth pulverizer added (hypothetical data) corresponding to past historical operation:

When 1 pulverizer mill out of service	-	400 MW;
When 2 pulverizer mills out of service	-	300 MW;
When 3 pulverizer mills out of service	-	200 MW;
When 4 pulverizer mills out of service	-	100 MW;
When 5 pulverizer mills out of service	-	0 MW.

2. Unit external/economic unavailability factor is not affected by this improvement project. Consequently, for this improvement project

$$\Delta EUF_{EE} = 0\% \quad (50)$$

Evaluate ΔEAF for Improvement Project

To quantify the effect of the improvement project of the fifth pulverizer mill, a hypothetical pulverizer mill equivalent unavailability factor needs to be determined if five pulverizer mills are in the unit. This section describes the calculation of EUF_F using the above assumptions.

The ΔEAF for the improvement project is then found by combining the hypothetical pulverizer mill equivalent unavailability factor with the historical pulverizer mill equivalent unavailability factor obtained in section 6.2.

6.3.1 EUF_F Calculation

Recalling from equation (3) in section 5.1.1,

$$EUF_F = \left(\frac{em}{eM} \right) \frac{SH}{PH} \times 100 \quad (3)$$

where

- EUF_F = Unit equivalent unavailability factor due to pulverizer mill events with improvement project implemented
- em = Equivalent meantime-to-restore when pulverizer mills controlling unit GAC with improvement project implemented
- eM = Equivalent meantime-to-event for pulverizer mills with improvement project implemented
- SH = Unit service hours with five pulverizer mills installed
- PH = Period hours

Since the hypothetical event data has been constructed over the month of January, the time period is given by equation (42), which is:

$$PH = 744 \text{ hours} \quad (42)$$

The unit service hours with five pulverizer mills installed is found using equation (19) in section 5.1.1., which is:

$$SH = SH_{no} + \Delta SH \quad (19)$$

where

SH_{no} = 694 hours; historical service hours in month of January [from equation (43)]

ΔSH = Change in unit service hours had five pulverizer mills been installed in unit in time period (month of January)

When an improvement project is implemented on a component, which has historically only resulted in unit derates, then the improvement project will result in no increase in the unit service hours. Thus for this improvement project,

$$\Delta SH = 0 \quad (51)$$

Putting equations (43) and (51) into equation (19) gives:

$$SH = 694 \text{ hours} \quad (52)$$

Since this improvement project involves no change in unit maintenance or operation practices, the methodology suggests the use of the following assumption:

$$em = em_{no} \quad (53)$$

Putting equation (45) into equation (53) gives:

$$em = 5.45 \text{ hours} \quad (54)$$

Because the pulverizer mills in the unit are repairable with the unit on-line, em in equation (3) is found by using the

formulas given in Table 3 of section 5.1.1. Since the unit has five pulverizer mills and four are required for the unit to achieve its GMC, Table 3 is entered with values of $r = 4$ and $n = 5$. Therefore, eM is found by the formula:

$$eM = \frac{M_1}{4} + \frac{M_1^2}{20m} \quad (55)$$

where

M_1 = Meantime-to-event for single component based on historical data in ERF's 1-9 ($M_1 = M_{1no}$)

m = Meantime-to-restore single component in system based on historical data in ERF's 1-9 ($m = m_{no}$)

Table 8 gives the values of $(m)_i$ for the five pulverizer mill events listed in the GADS ERF's.

TABLE 8 VALUES OF $(m)_i$ FOR PULVERIZER MILL EVENTS LISTED IN GADS ERF's	
Event i (Numbers correspond to GADS ERF's)	$(m)_i$ (Hours)
1	40
3	34
4	19
7	4
8	31

The parameter M_1 in equation (55) is found using equation (14) in section 5.1.1, which is repeated below as:

$$M_1 = r \frac{SH}{n} \quad (14)$$

where

r = 4; number of pulverizer mills required operational for unit to achieve its gross maximum capacity

SH = 694 hours from equation (52); number of unit service hours in time period

n = 5; number of pulverizer events in time period

Putting the values of r , SH , and n into equation (14) gives:

$$M_1 = \frac{(4)(694)}{5} = 555.2 \text{ hours} \quad (56)$$

The parameter m in equation (55) is found using equation (17) in section 5.1.1, which is:

$$m = \frac{1}{n} \sum_{i=1}^n m_i \quad (17)$$

where

m = Meantime-to-restore single component in system based on unit historical data, hours

m_i = Meantime-to-restore single component in i th pulverizer mill event, hours

Putting the values of n and m_i given in Table 8 into equation (17) gives:

$$m = \frac{40 + 34 + 19 + 4 + 31}{5} = 25.6 \text{ hours} \quad (57)$$

Inserting equations (56) and (57) into equation (55) gives:

$$\begin{aligned} eM &= \frac{555.2}{4} + \frac{(555.2)^2}{(20)(25.6)} \\ &= 138.8 + 602.0 = 740.8 \text{ hours} \end{aligned} \quad (58)$$

Finally, combining equations (42), (52), (54), and (58) into equation (3) gives:

$$EUF_F = \frac{5.45}{(740.8)} \left(\frac{694}{744} \right) \times 100 = .69\% \quad (59)$$

Combining the unit equivalent unavailability factor considering the addition of the fifth pulverizer, EUF_F in equation (59), with the equivalent unavailability factor without the fifth pulverizer, EUF_{Fno} obtained in equation (49), gives the ΔEUF_F for adding a fifth pulverizer:

$$\Delta EUF_F = .69 - 3.66 = -2.97\% \quad (60)$$

6.3.2 ΔEAF Calculation

The ΔEAF from the improvement project of adding the fifth pulverizer is found by equation (1) as:

$$\Delta EAF = -\Delta EUF_F - \Delta EUF_{EE} \quad (1)$$

Inserting ΔEUF_F in equation (60) and the ΔU_{EE} in equation (50) into equation (1) gives:

$$\Delta EAF = 2.97 + 0 = 2.97\% \quad (61)$$

Physically, equation (61) implies that installing a fifth pulverizer at the unit would result in the unit producing 10.8 more full power days of energy per year of operation. A

technique for determining the economics of understanding such an improvement project is outlined in Appendix C of the handbook.

Figure 16 shows the historical GAG profile and hypothetical GAG profile for the unit with the addition of the fifth pulverizer improvement project. The hypothetical GAG profile has been constructed by adding 100 MW to the unit's historical GAG profile wherever the pulverizer mills were controlling the unit load.

This graphical procedure is not exact because it implies that the spare pulverizer never fails when used. The ΔEAF calculated from the graphical profile is 3.02, which is slightly higher than that given in equation (61). The difference between these ΔEAF 's is that equation (61) accounts for failures of the spare pulverizer while the graphical profile does not. It is not necessary to construct this hypothetical profile in applying the methodology. However, this profile has been added to give better insight into the reader to understand how this improvement changes the unit's productivity.

6.4 EXAMPLE 2: EFFECT ON UNIT EQUIVALENT AVAILABILITY FACTOR FOR INSTALLING MORE RELIABLE COMPONENTS WITHIN THE UNIT

Define Improvement Project

The unit described in sections 6.0 and 6.1 has a system containing pulverizer mills. Since a number of the pulverizer mill events that resulted in loss of unit power involved belt failures, the improvement project evaluated in this section involves the installation of more reliable belts. The ΔEAF of the unit predicted by the methodology for this improvement project is illustrated below.

Develop Assumptions of Improvement Project Effect on Unit Historical Data

The following assumptions are made regarding the impact of more reliable pulverizer mill belts on the unit historical pulverizer mill event data in order to construct the corresponding hypothetical data.

1. The new, more reliable belts have such a low failure rate that it can be assumed that all hypothetical events corresponding to historical pulverizer mill events due to belt failures are eliminated by the improvement project.

HISTORICAL AND HYPOTHETICAL GAG PROFILE FOR FIFTH PULVERIZER IMPROVEMENT PROJECT

Figure 16

2. Unit external/economic unavailability factor is not affected by this improvement project. Consequently, for this improvement project:

$$\Delta EUF_{EE} = 0\%$$

(62)

Construct and Format Hypothetical Unit Data Based on Improvement Project and Stated Assumptions

The use of the more reliable belts in the pulverizer mills eliminates those derates that resulted from belt failures. Each of the pulverizer mill events that resulted from belt failures (ERF's 1 and 8) must be carefully studied in light of the above two assumptions to determine the hypothetical unit event data; i.e., how the unit would have operated had the pulverizer belts not failed.

Historical events (ERF's 3, 4, and 7) are not affected by the improvement project and are, therefore, unchanged by the hypothetical pulverizer mill events. Hypothetical external/economic data (ERF's 2, 5, and 9) also have not been changed from the historical external/economic event data since the improvement project doesn't affect external/economic event data. Only historical events reported on ERF's 1 and 8 are affected by this improvement project, and both events are eliminated.

Figure 17 is a plot of the historical GAG profile developed in section 6.1 and the hypothetical GAG profile for this example constructed by eliminating Event Report Forms 1 and 8. The shaded area represents the difference between the hypothetical GAG profile resulting from improving the reliability of the pulverizer belts and the previous historical GAG profile.

Evaluate ΔEAF for Improvement Project

To evaluate the improvement project of more reliable pulverizer mill belts, the unit pulverizer mill and equivalent unavailability factor need to be determined. This section describes the calculation of EUF_F . The ΔEAF for the improvement project is then found by combining the pulverizer mill hypothetical equivalent unavailability factor with the pulverizer mill historical equivalent unavailability factor previously obtained in section 6.2.

HISTORICAL AND HYPOTHETICAL GAG PROFILE FOR MORE RELIABLE BELT IMPROVEMENT PROJECT

Figure 17

6.4.1 EU_F Calculation

Recalling from equation (3) in section 5.1.1 that the unavailability factor due to pulverizer belt failures can be found from:

$$EU_{F} = \left(\frac{em}{eM} \right) \cdot \frac{SH}{PH} \times 100 \quad (3)$$

Since the hypothetical event data has been constructed over the month of January, the time period is given by equation (42), which is

$$PH = 744 \text{ hours} \quad (42)$$

The unit service hours with more reliable pulverizer mill belts installed is found using equation (19) in section 5.1.1, which is

$$SH = SH_{no} + \Delta SH \quad (19)$$

where

SH_{no} = 694 hours; historical service hours in month of January [from equation (43)]

ΔSH = Change in unit service hours following installation of more reliable pulverizer mill belts in time period (month of January)

Since the pulverizer mills only resulted in unit derates, this improvement project will result in no increase in unit service hours. Thus, for this improvement project:

$$\Delta SH = 0 \quad (63)$$

Putting equations (43) and (63) into equation (19) gives:

$$SH = 694 \text{ hours} \quad (64)$$

The parameter em is obtained by using equation (4) in section 5.1.1 which, when equations (5), (6), and (7) are inserted, becomes:

$$em = \frac{\sum_{i=1}^n (UND)_i (m)_i}{(n) (GMC)} \quad (65)$$

where

n = 3; number of hypothetical events for pulverizer mills remaining after improvement project

Table 9 gives values of $(UND)_i$ and $(m)_i$ for the three events that remain after the improvement project has been instituted. Table 9 has been constructed directly from Table 7.

TABLE 9 VALUES OF $(UND)_i$ AND $(m)_i$ FOR PULVERIZER MILL HYPOTHETICAL EVENTS LISTED ON ERF'S		
GADS ERF Event #	$(UND)_i$ (MW)	$(m)_i$ (Hours)
1	(Eliminated)	
3	100	25
3	0	9
4	100	19
7	0	4
8	(Eliminated)	

Putting the values of $(UND)_i$ and $(m)_i$ in Table 9 into equation (65), along with the value of n and the unit GMC, gives:

$$\begin{aligned}
 em &= \frac{(100)(25) + (0)(9) + (100)(19) + (0)(4)}{(3) (400)} \\
 &= 3.67 \text{ hours} \quad (66)
 \end{aligned}$$

Because the pulverizer mills in the unit are repairable with the unit on-line, eM in equation (3) is found by using the formulas given in Table 3 (section 5.1.1). Since the unit has four pulverizer mills and four are required for the unit to achieve its GMC, Table 3 is entered with values of $r = 4$ and $n' = 4$. Therefore, eM is found by the formula:

$$eM = \frac{M_1}{4} \quad (67)$$

The parameter M_1 in equation (67) is found using equation (14) in section 5.1.1, which is repeated below as:

$$M_1 = r \frac{SH}{n} \quad (14)$$

Putting the values of r , SH , and n into equation (14) gives:

$$M_1 = \frac{(4)(694)}{3} = 925.3 \text{ hours} \quad (68)$$

Inserting equation (68) into equation (67) gives:

$$eM = \frac{925.3}{4} = 231.3 \text{ hours} \quad (69)$$

Finally, combining equations (42), (64), (66), and (69) into equation (3) gives:

$$EUF_F = \frac{3.67}{231.3} \left(\frac{694}{744} \right) \times 100 = 1.48\% \quad (70)$$

Combining EUF_F in equation (70) with the historical value ($EUF_{F_{no}}$) obtained in equation (49) gives the ΔEUF_F for adding more reliable pulverizer mill belts as:

$$\Delta EUF_F = 1.48 - 3.66 = -2.18\% \quad (71)$$

6.4.2 ΔEAF Calculation

The ΔEAF from the improvement project of adding more reliable pulverizer belts is found by equation (1) as:

$$\Delta EAF = -\Delta EUF_F - \Delta EUF_{EE} \quad (1)$$

Inserting ΔEUF_F found in equation (71) and the ΔU_{EE} given in equation (62) into equation (1) gives:

$$\Delta EAF = 2.18 + 0 = 2.18\% \quad (72)$$

Physically, equation (72) implies that installing more reliable pulverizer mill belts at the unit would result in the unit producing 7.9 more full power days of energy per year of operation. A technique for determining the economics of undertaking such an improvement project is outlined in Appendix C of the handbook.

6.5 EXAMPLE 3: EFFECT ON UNIT EQUIVALENT AVAILABILITY FACTOR FOR IMPROVED LOGISTICS SUPPORT AND SPARE PARTS CONTROL

Define Improvement Project

The unit described in sections 6.0 and 6.1 has a system containing four pulverizer mills. The historical outage data shows several of the pulverizer mill events involved delays while servicing due to lack of spare parts. The improvement project evaluated in this section is to increase the unit spare parts inventory of pulverizer mill parts to such an extent that future delays from lack of spare parts are essentially eliminated. The ΔEAF of the unit predicted by AIM for this improvement project is illustrated by the calculations below.

Develop Assumptions of Improvement Project Effect on Unit Historical Data

The following assumptions are made regarding the impact of an increased pulverizer mill spare parts inventory on the

unit historical pulverizer mill event data in order to construct corresponding hypothetical data:

1. All spare part delays for hypothetical events corresponding to historical pulverizer mill events are eliminated by the improvement project.
2. Unit external/economic unavailability factor is not affected by this improvement project. Consequently, for this improvement project:

$$\Delta EUF_{EE} = 0\% \quad (73)$$

Construct and Format Hypothetical Unit Data Based on Improvement Project and Stated Assumptions

The addition of a spare parts inventory has the effect to reduce the outage time of those derates from pulverizer mill failures that were extended due to lack of spare parts. Of the five pulverizer mill events described on the GADS ERF's 1, 3, 4, 7, and 8, three were extended due to lack of spare parts; namely, event no. 1 (8 hours), event no. 3 (28 hours), and event no. 8 (6 hours). The data for these three events must be carefully studied in light of the above assumptions to determine the hypothetical unit event data; i.e., how the servicing of the pulverizer mills would have occurred had an adequate spare parts inventory existed at the unit. The hypothetical data for this improvement project shows that historical events 2, 4, 5, 6, 7, and 9 are unaffected, while historical events 1, 3, and 8 are shortened by the times of the previous spare parts delays stated above.

Figure 18 is a plot of the historical GAG profile developed in section 6.1 and the hypothetical GAG profile for this example as constructed from the hypothetical data. The shaded area represents the difference between the hypothetical GAG profile and the historical GAG profile.

Evaluate ΔEAF for Improvement Project

To evaluate the improvement project of improved spare parts inventory, the unit pulverizer mill equivalent unavailability factor needs to be determined. This section describes the calculation of EUF_F from the hypothetical data developed above. The ΔEAF for the improvement project is then found by combining the hypothetical equivalent unavailability factor with the unit historical equivalent unavailability factor obtained in section 6.2.

HISTORICAL AND HYPOTHETICAL GAG PROFILE FOR IMPROVED SPARE PARTS IMPROVEMENT PROJECT

Figure 18

6.5.1 EU_F Calculation

Recalling from equation (3) in section 5.1.1:

$$EU_{F_F} = \left(\frac{\bar{e}m}{eM} \right) \frac{SH}{PH} \times 100 \quad (3)$$

Since the hypothetical event data has been constructed over the month of January, the time period is given by equation (42), which is:

$$PH = 744 \text{ hours} \quad (42)$$

The unit service hours with improved spare parts inventory is similar to that given in Examples 1 and 2. Consequently, for this improvement project SH is given by equation (52) in Example 1 as:

$$SH = 694 \text{ hours} \quad (52)$$

The parameter e_m in equation (3) is found by adding equations (5) through (7) in section 5.1.1, which was given as equation (65) in Example 2:

$$e_m = \frac{\sum_{i=1}^n (UND)_i (m)_i}{(n) (GMC)} \quad (65)$$

where

$$n = 5; \text{ number of hypothetical events for pulverizer mills with continuous maintenance in time period } PH$$

Table 10 gives values of $(UND)_i$ and $(m)_i$ for the five pulverizer mill events listed. Table 10 is constructed from the data in ERF's 1, 3, 4, 7, and 8. The construction of the data in Table 10 can most easily be understood from Figure 18 and Table 7.

TABLE 10 VALUES OF $(UND)_i$ AND $(m)_i$ FOR PULVERIZER MILL HYPOTHETICAL EVENTS FOR EXAMPLE 3		
Event i	$(UND)_i$ (MW)	$(m)_i$ (Hours)
1	100	32
3	100	6
4	100	19
7	0	4
8	100	25

Event no. 1 with no spare parts delay would be reduced by eight hours and no longer be concurrent with the external/ economic event no. 2. Thus, event no. 1 would be initiated at the same historical time (0800 1/2/79) but extend only to 1600 1/3/79, which is a duration of 32 hours. The unit derating in this time period is not affected by the improvement project and is shown as 100 MW.

Event no. 3 with no spare parts delay would be reduced by 28 hours and no longer be concurrent with either pulverizer mill event no. 4 or the external/economic event no. 5. Thus event no. 3 is shown in Figure 4 as beginning at 1200 - 1/6/79 and terminating at 1800 - 1/6/79. This 6-hour outage duration is developed by subtracting the spare part delay (28 hours) from the outage repair time for historical event no. 3 (34 hrs.).

Event nos. 4 and 7 are not affected by the improvement project as there are no spare parts delay in these events. The UND_i and m_i for these two events are the same as given for the historical event nos. 4 and 7 in Table 7.

Event no. 8 with no spare parts delay is reduced by six hours and, consequently, is no longer concurrent with the external/economic event no. 9. Thus, event no. 8 is shown as beginning at 1200 1/14/79 and terminating at 1300 1/15/79. The entire outage duration for this event is 25 hours during which time the unit is derated 100 MW.

It should be understood that had the improvement project not made event nos. 1, 3, and 8 nonconcurrent, the UND_i would have to be evaluated considering overlapping effects. In this situation, UND_i would not necessarily have been constant over each event duration as shown in Table 10.

Putting the values of $(UND)_i$ and $(m)_i$ in Table 10 into equation (65), along with the value of n and the unit GMC, gives:

$$e_m = \frac{(100)(32) + (100)(6) + (100)(19) + (0)(4) + (100)(25)}{(5)(400)}$$

$$= 4.1 \text{ hours} \quad (74)$$

Because the pulverizer mills in the unit are repairable with the unit on-line, eM in equation (3) is found by using the formulas given in Table 3 (section 5.1.1). Since the unit has four pulverizer mills and four are required for the unit to achieve its GMC, Table 3 is entered with values of $r = 4$ and $n = 4$. Therefore, eM is found by the formula:

$$eM = \frac{M_1}{4} \quad (75)$$

The parameter M_1 in equation (75) is found using equation (14) in section 5.1.1, which is repeated below as:

$$M_1 = r \frac{SH}{n} \quad (14)$$

Putting the values of r , SH , and n into equation (14) gives:

$$M_1 = \frac{(4)(694)}{5} = 555.2 \text{ hours} \quad (76)$$

Inserting equation (76) into equation (75) gives:

$$eM = \frac{555.2}{4} = 138.8 \text{ hours} \quad (77)$$

Finally, combining equations (42), (52), (74), and (77) into equation (3) gives:

$$EUF_F = \left(\frac{4.1}{(138.8)} \right) \frac{694}{744} \times 100 = 2.76\% \quad (78)$$

Combining EUF_F in equation (78) with the EUF_{Fno} in equation (49) gives the ΔEUF resulting from eliminating delays in servicing the mills by adding a pulverizer mill spare parts inventory as:

$$\Delta EUF_F = 2.76 - 3.66 = -.90\% \quad (79)$$

6.5.2 ΔEAF Calculation

The ΔEAF from the improvement project of increasing pulverizer mill spare parts inventory is found by equation (1) as:

$$\Delta EAF = -\Delta EUF_F - \Delta EUF_{EE} \quad (1)$$

Inserting ΔEUF_F found in equation (79) and the ΔEUF_{EE} given in equation (73) into equation (1) gives:

$$\Delta EAF = .90 + 0 = .90\% \quad (80)$$

Physically, equation (80) implies that increasing the pulverizer mill spare parts inventory at the unit would result in the unit producing 3.3 more full power days of energy per year of operation.

6.6   EXAMPLE 4: EFFECT ON UNIT EQUIVALENT AVAILABILITY
                         FACTOR OF IMPROVED MAINTENANCE MANPOWER
                                         CONTROL

Define Improvement Project

Several of the pulverizer mill events involved delays while servicing due to unavailability of work crew; consequently, the improvement project evaluated in this section is to make sufficient work crews available so as to ensure continuous maintenance of pulverizer mill events whenever they occur and to eliminate these delays. The ΔEAF of the unit predicted by AIM for this improvement project is illustrated in this section.

Develop Assumptions of Improvement Project Effect
on Unit Historical Data

The following assumptions are made regarding the impact of continuous maintenance on the unit historical pulverizer mill event data in order to construct corresponding hypothetical data:

1. All delays due to work crews unavailable in hypothetical events corresponding to historical pulverizer mill events are eliminated by the improvement project.
2. Unit external/economic unavailability factor is not affected by this improvement project. Consequently, for this improvement

$$\Delta EUF_{EE} = 0\% \qquad (81)$$

Construct and Format Hypothetical Unit Data Based on
Improvement Project and Stated Assumptions

The addition of additional work crews has the effect to reduce the outage time of those derates from pulverizer mill failures that were extended due to the lack of repair crews. Of the five pulverizer mill events described on GADS ERF's 1, 3, 4, 7, and 8, three were extended due to lack of service crews; namely, event no. 1 (24 hours), event no. 4 (14 hours), and event no. 8 (21 hours). The data for these three events must be carefully studied in light of the above assumptions to determine the hypothetical unit event data; i.e., how the

servicing of the pulverizer mills would have occurred had an adequate service crew existed during the unit derating from pulverizer mill failures. The hypothetical data for this improvement project is that historical event nos. 2, 3, 5, 6, 7, and 9 are unaffected, while historical event nos. 1, 4, and 8 are shortened by the times of the servicing delays stated above.

Figure 19 is a plot of the historical GAG profile developed in section 6.1 and the hypothetical GAG profile for this example constructed from the hypothetical data. The shaded area represents the difference between the hypothetical GAG profile and the historical GAG profile.

Evaluate ΔEAF for Improvement Project

To evaluate the improvement project for continuous maintenance, the unit pulverizer mill equivalent unavailability factor needs to be determined. This section describes the calculation of EU_{F_F} using the hypothetical data developed above. The ΔEAF for the improvement project is found by combining hypothetical equivalent unavailability factor with the unit historical equivalent unavailability factor obtained in section 6.2.

6.6.1 EU_{F_F} Calculation

Recalling equation (3) in section 5.1.1:

$$U_F = \left(\frac{em}{eM} \right) \frac{SH}{PH} \times 100 \quad (3)$$

Since the hypothetical event data has been constructed over the month of January, the period hours are given by equation (42), which is:

$$PH = 744 \text{ hours} \quad (42)$$

The unit service hours with continuous maintenance is similar to that given in the three previous examples. Consequently, for this improvement project, SH is given as:

$$SH = 694 \text{ hours} \quad (82)$$

HISTORICAL AND HYPOTHETICAL GAG PROFILE FOR
IMPROVED MAINTENANCE/MANPOWER CONTROL IMPROVEMENT PROJECT

Figure 19

The parameter e_m in equation (3) is found by adding equations (5) through (7) in section 5.1.1, which was given as equation (65) in Example 2:

$$e_m = \frac{\sum_{i=1}^n [(UND)_i + (m)_i]}{[n] \cdot [GDC]} \quad (65)$$

where

n = 5; number of hypothetical events for pulverizer mills with improved spare parts control in time period PH

Table 11 gives values of $(UND)_i$ and $(m)_i$ for the five events listed. The construction of the data in Table 11 can most easily be understood from Figure 18 and Table 7.

TABLE 11		
VALUES OF $(UND)_i$ AND $(m)_i$ FOR PULVERIZER MILL		
EVENTS FOR EXAMPLE 4		
Event i	$(UND)_i$ (MW)	$(m)_i$ (Hours)
1	100	16
3	100	25
3	0	9
4	100	5
7	0	4
8	100	10

Event no. 1 with continuous maintenance at the unit would be reduced by 24 hours. In addition, it would no longer be concurrent with the external/economic event no. 2. Thus, event no. 1 would begin at the same historical time (0800 - 1/2/79) but extend only to 2400 1/2/79, which is a duration of 16 hours. The unit derating during this time period is not affected by the improvement project and is a constant value of 100 MW.

Event nos. 3 and 7 are not affected by the improvement project as there are no service delays in these events. The UND_i and m_i for these two events are the same as given for the historical events 3 and 7 in Table 7.

Event no. 4 with continuous maintenance would be reduced by 14 hours. This would reduce the time duration of event no. 4 from its historical value of 19 hours to 5 hours. Since event no. 4 is nonconcurrent with event no. 5 and directly additive to event no. 3, the unit derating is shown as a constant 100 MW during this event.

Event no. 8 with continuous maintenance is reduced by 21 hours and, consequently, is no longer concurrent with external/economic event no. 9. This improvement, therefore, results in a reduction in the time duration of hypothetical event no. 8 from its historical value of 31 hours to 10 hours. During this time, the unit is derated at a constant 100 MW.

Putting the values of $(UND)_i$ and $(m)_i$ in Table 11 into equation (65), along with the value of n and the unit GMC, gives:

$$e_m = \frac{(100)(16) + (100)(25) + (0)(9) + (100)(5) + (0)(4) + (100)(10)}{(5) \quad (400)}$$

$$= 2.8 \text{ hours} \quad (83)$$

Since the pulverizer mills in the unit are repairable with the unit on-line, eM in equation (3) is found by using the formulas given in Table 3 (section 5.1.1). Since the unit has four pulverizer mills and four are required for the unit to achieve its GMC, Table 3 is entered with values of $r = 4$ and $n' = 4$. Therefore, eM is found by formula:

$$eM = \frac{M_1}{4} \quad (84)$$

The parameter M_1 in equation (84) is found using equation (14) in section 5.1.1, which is repeated below as:

$$M_1 = r \frac{SH}{n} \quad (14)$$

Putting the values of r , SH , and n into equation (14) gives:

$$M_1 = \frac{(4) (694)}{5} = 555.2 \text{ hours} \quad (85)$$

Inserting equation (85) into equation (14) gives:

$$eM = \frac{555.2}{4} = 138.8 \text{ hours} \quad (86)$$

Finally, combining equations (42), (82), (83), and (86) into equation (3) gives:

$$EUF_F = \left(\frac{2.8}{(138.8)} \right) \frac{694}{744} (100) = 1.88\% \quad (87)$$

Combining EUF_F in equation (87) with the historical value, $EUF_{F_{no}}$, obtained in equation (49) gives the ΔEUF_F for implementing improvement project 4 -- improved maintenance manpower control:

$$\Delta EUF_F = 1.88 - 3.66 = -1.78\% \quad (88)$$

6.6.2 ΔEAF Calculation

The ΔEAF from the improvement project of adding improved maintenance manpower control is found by equation (1) as:

$$\Delta EAF = -\Delta EUF_F - \Delta EUF_{EE} \quad (1)$$

Inserting ΔEUF_F found in equation (88) and the ΔEUF_{EE} given in equation (81) into equation (1) gives:

$$\Delta EAF = 1.78 + 0 = -1.78\% \quad (89)$$

Physically, equation (89) implies that adding improved maintenance at the unit would result in the unit producing 6.5 more full power days of energy per year of operation.

6.7 EXAMPLE 5: EFFECT ON UNIT EQUIVALENT AVAILABILITY FACTOR FOR IMPROVED PREVENTIVE MAINTENANCE CONTROL

Define Improvement Project

Some of the pulverizer mill events involved failed pulverizer mill belts. Consequently, the improvement project evaluated in this section is to replace the pulverizer mill belts on a monthly basis in order to eliminate such events. The ΔEAF of the unit predicted by the methodology for this improvement project is illustrated in this section.

Develop Assumptions of Improvement Project Effect on Unit Historical Data

The following assumptions are made regarding the impact of monthly pulverizer mill belt replacement on the unit historical pulverizer mill event data in order to construct the corresponding hypothetical data:

1. All events caused solely by failure of pulverizer mill belts are eliminated by this improvement project.
2. Belt replacement on a single pulverizer takes 16 man-hours. All four pulverizers have their belts replaced consecutively in a single event at the beginning of each month at which time the unit is continuously derated to a power of 300 MW. Two-man crew size assigned

continuously to perform maintenance. Consequently, repair time for each pulverizer is eight hours.

3. Unit external/economic unavailability factor is not affected by this improvement project. Consequently, for this improvement

$$\Delta EUF_{EE} = 0\% \quad (90)$$

Construct Hypothetical Unit Data Based on Improvement Project and Stated Assumptions

This improvement project has the effect to eliminate historical pulverizer events due to belt failures by replacing them with a controlled preventive maintenance derate event. Of the five pulverizer mill events described on GADS ERF's 1, 3, 4, 7, and 8, two were caused by belt failures; namely, event no. 1 (40 hours) and event no. 5 (25 hours). From assumption 1, these two events are eliminated. However, the unit is assumed to have its hypothetical GAG profile and energy produced adjusted only during those portions of events 1 and 5 where no other concurrent derates are occurring. By assumption 2, a new preventive maintenance event is added at the start of the month. Since the unit has four pulverizers and each pulverizer has a repair time of eight hours, this preventive maintenance event lasts 32 hours.

Figure 20 is a plot of the historical GAG profile developed in section 6.1 and the hypothetical GAG profile for this example constructed from the assumptions above. The shaded areas represent the difference between the hypothetical GAG profile and the historical GAG profile.

Evaluate ΔEAF for Improvement Project

To evaluate the improvement project of preventive maintenance on the mill belts, the unit pulverizer mill equivalent unavailability factor needs to be determined. This section describes the calculation of EUF_F using the unit hypothetical data. The ΔEAF for this improvement project is found by combining EUF_F and the $EUF_{F_{no}}$ obtained in section 6.2.

HISTORICAL AND HYPOTHETICAL GAG PROFILE FOR PERFORMING
PREVENTIVE MAINTENANCE OF MONTHLY CHANGING PULVERIZER MILL BELTS

Figure 20

6.7.1 EUF_F Calculation

Recalling equation (3) in section 5.1.1,

$$U_F = \left(\frac{em}{eM} \right) \cdot \frac{SH}{PH} \times 100 \quad (3)$$

Since the hypothetical event data has been constructed over the month of January, the period hours are given by equation (42) which is:

$$PH = 744 \text{ hours} \quad (42)$$

The unit service hours are similar to that given in the four previous examples. Consequently, for this improvement project SH is given as:

$$SH = 694 \text{ hours} \quad (91)$$

The parameter em in equation (3) is found by equation (65), which is:

$$em = \frac{\sum_{i=1}^n (UND)_i (m)_i}{(n) (GMC)} \quad (65)$$

where

n = 4; number of hypothetical events for pulverizer mills with performing preventive maintenance on pulverizer mill belts

Table 12 gives values of $(UND)_i$ and $(m)_i$ for the five events listed. Table 12 can be constructed from Figure 20 or Table 6 and the assumptions associated with this improvement project.

TABLE 12		
VALUES OF $(UND)_i$ AND $(m)_i$ FOR PULVERIZER MILL EVENTS FOR EXAMPLE 5		
Event i	$(UND)_i$ (MW)	$(m)_i$ (Hours)
1*	100	32
1	(Eliminated)	
3	100	25
3	0	9
4	100	19
7	0	4
8	(Eliminated)	

Event no. 1* in Table 12 is the preventive maintenance derate which extends for 32 hours (0000 1/1/79 to 0800 1/2/79). During this time period, there are no other events occurring at the unit so the UND for this event is taken as 100 MW.

Events 1 and 8 are eliminated by the improvement project and are not included in Table 12. Events 3, 4, and 7 are not affected by this improvement project. The UND_i and m_i shown in Table 12 is taken directly from the historical data for these events, which is listed in Table 7.

Putting the values of $(UND)_i$ and $(m)_i$ in Table 12 into equation (65), along with the value of n and the unit GMC gives:

$$\begin{aligned}
 em &= \frac{(100)(32) + (100)(25) + (0)(9) + (100)(19) + (0)(4)}{(4)(400)} \\
 &= 4.75 \text{ hours}
 \end{aligned}
 \tag{92}$$

Since the pulverizer mills in the unit are repairable with the unit on-line, eM in equation (3) is found by using the formulas given in Table 3, section 5.1.1. Since the unit has four pulverizer mills and four are required for the unit to achieve its GMC, Table 3 is entered with values of $r = 4$ and $n' = 4$. Therefore, eM is found by the formula:

$$eM = \frac{M_1}{4} \quad (93)$$

The parameter M_1 in equation (93) is found using equation (14) in section 5.1.1, which is repeated below as:

$$M_1 = r \frac{SH}{n'} \quad (14)$$

Putting the values of r , SH , and n' into equation (14) gives:

$$M_1 = \frac{(4)(694)}{4} = 694 \text{ hours} \quad (94)$$

Inserting equation (94) into equation (14) gives:

$$eM = \frac{694}{4} = 173.5 \text{ hours} \quad (95)$$

Finally, combining equations (42), (91), (92), and (95) into equation (3) gives:

$$EUF_F = \left(\frac{4.75}{(173.5)} \right) \left(\frac{694}{744} \right) \left(100 \right) = 2.55 \% \quad (96)$$

Combining EUF_F in equation (96) with the historical value $EUF_{F_{no}}$ obtained in equation (49) gives the ΔEUF_F for adding a preventive maintenance program (improvement project 5) as:

$$\Delta EUF_F = 2.55 - 3.66 = -1.11\% \quad (97)$$

6.7.2 ΔEAF Calculation

The ΔEAF from the improvement project of performing preventive maintenance on the pulverizers is found by equation (1) as:

$$\Delta EAF = -\Delta EUF_F - \Delta EUF_{EE} \quad (1)$$

Inserting ΔEUF_F found in equation (97) and the ΔEUF_{EE} in equation (90) into equation (1) gives:

$$\Delta EAF = 1.11 + 0 = 1.11\% \quad (98)$$

Physically, equation (98) implies that performing preventive maintenance on the belts at the beginning of each month results in the unit producing 4.0 more full power days of energy per year of operation.

6.8 SUMMARY OF IMPROVEMENT PROJECTS

The AIM methodology was used to evaluate the following five improvement projects:

- ° Example 1 -- Addition of a fifth pulverizer;
- ° Example 2 -- Use of more reliable pulverizers;
- ° Example 3 -- Improved logistics support and spare parts control;
- ° Example 4 -- Improved maintenance manpower control;
- ° Example 5 -- Improved preventive maintenance control.

For each project, the change in the unit equivalent unavailability factor due to effect of the project on plant component events (EUF_F) was calculated. These were then compared to the equivalent unavailability calculated for the historical operation of the plant with no improvement project implemented ($EUF_{F_{no}}$) to develop the change in unit equivalent

unavailability (ΔEUF_F). Table 13 summarizes these parameters for both the historical operation of the plant and expected plant operation after implementation of these improvement projects.

Because these five improvement projects are interrelated, if all five were implemented, the change in equivalent availability factor would not equal the sum of the five individual projects. The final ranking of improvement projects should be determined by the economic methods shown in Appendix C which are based on the ΔEAF generated by the AIM methodology.

TABLE 13 SUMMARY OF UNIT EQUIVALENT UNAVAILABILITY FACTORS FOR FIVE EXAMPLES ILLUSTRATED IN SECTION 6.0					
	Unit Equivalent Unavailability Factor Due to Pulverizer Mills	ΔEUF_F (%)	ΔEUF_{EE} (%)	ΔEAF (%)	Additional Days of Power Production Per Year Resulting From Improvement Project
Historical Plant Operation	3.66	-0-	-0-	-0-	-0-
Example 1	.69	-2.97	-0-	2.97	10.8
Example 2	1.48	-2.18	-0-	2.18	7.9
Example 3	2.76	- .90	-0-	.90	3.3
Example 4	1.88	-1.78	-0-	1.78	6.5
Example 5	2.55	-1.11	-0-	1.11	4.0

REFERENCES

- [1] U. S. Department of Energy, Economic Regulatory Administration, Division of Power Supply and Reliability, "Power Plant Productivity Improvement Study: Volumes I - IV," prepared by Mechanics Research, Incorporated for DOE, HCP/B60830-02, February 1978.
- [2] Illinois Commerce Commission, "Power Plant Productivity Improvement Study - Final Report," prepared by Trident Engineering Associates, Inc., Annapolis, Maryland, November 17, 1978.
- [3] Regional Seminars on Availability Engineering and Power Plant Productivity Improvement, sponsored by U. S. Department of Energy, EPRI, NERC, and EEI, June 1978, Workshops: March 1979.
- [4] U. S. Department of Energy, "Guide for Prioritizing Power Plant Productivity Improvement Projects - Modification and Simplification of the DOE/MRI Methodology," prepared by Trident Engineering Associates, Inc., Annapolis, Maryland, March 1981.
- [5] "IEEE Trial-Use Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability and Productivity," published by The Institute of Electrical and Electronics Engineers, New York, December 1980.
- [6] National Electric Reliability Council, "Data Reporting Instructions for Generating Availability Data Systems," Princeton, New Jersey, December 1980.
- [7] Robin, T. T. and Brickell, M. C., "Reliability of Operating Power Plants - a Utility Viewpoint," ASME Paper 77-JPGC/Pwr-10, ASME-IEEE Joint Power Generation Conference, September 1977.
- [8] Robin, T. T., Talty, T. F., and Porter, L. M., "Utility Experience with an Availability Improvement Program: Status and Current Direction," ASME Paper 80-JPGC/Pwr-18, ASME-IEEE Joint Power Generation Conference, October 1980.

APPENDIX A

GADS CAUSE/COMPONENT CODES

GADS CAUSE/COMPONENT CODES

The codes contained in this appendix are those established for the Generating Availability Data System (Reference 6). These codes are entered on the primary cause of event cards (ERF, card 02, columns 18-21) in order to provide an identification for each component that potentially affects plant availability.

The intent of the GADS cause/component codes is not to provide a code for all possible causes or all components, but to provide, in general terms, the cause or component that results in a reported event. The details concerning a more specific cause/component, the type of failure, method of repair/nature of work, repair effort and/or combination of preceding events are to be included in the verbal description.

When reporting an event, select the code which best describes the cause or component responsible for the event. The following criteria are to be used in selecting a code:

- ° The cause of the event is to be assigned to the major component or system that was responsible for the event and not to an auxiliary component or operation that triggered the failure of a major component or system.

For instance, failure of an air line to one feedwater regulating valve may cause closure of that valve, resulting in a boiler trip on low level. In this case, the cause code for the feedwater regulating valve would be reported, rather than the code for the service air system. The fact that the valve closure was triggered by an air line failure would be noted in the narrative description and reported as a contributing cause via the event contribution code. On the other hand, if the feedwater regulating valve closure had resulted from a complete loss of station air, the cause code for the station air system would be reported. In the later case, the station air system problem would result in malfunctions of numerous valves and instruments throughout the plant, and no one major component or system could be uniquely identified as initiating the outage.

- ° Power supplies (including motor control centers, breakers, etc.) which serve a particular component are to be reported using the code for that component.

Power supply systems that serve multiple components are to be reported using the code for the power supply system. For instance, if a breaker failure results in the loss of an FD fan, the code for the FD fan would be used. However, if a problem in the AC power distribution caused not only the loss of the FD fan but also several other major components, then the code for AC power distribution would be used.

- ° Instruments/controls (such as pressure switches, pressure regulators, position indicators, etc.) which are part of a particular fan, pump, or valve are to be reported using the code for that component.

Codes have been assigned to some control systems, such as feedwater control. All instruments, transmitters, logic modules, etc., associated with these systems are to be reported using the code for that control system.

- ° The codes for "External" and "Safety, Regulatory, and Environmental" are only to be used if no other cause/component code applies.

For instance, if stack emission limits are exceeded because of a fault in the flue gas scrubber, a scrubber code is to be used. However, if a new limit on emissions is imposed and is exceeded even though the scrubber is functioning properly, then an environmental code is to be used.

INDEX TO CAUSE COMPONENT CODES

Boiler

Boiler Fuel Supply	001-0480
Boiler Piping System	0500-0799
Boiler Internals and Structures	0800--850
Slag and Ash Removal	0860-0920
Boiler Tube Leaks	1000-1090
Boiler Tube Fireside Slagging or Fouling	1100-1200
Miscellaneous Boiler Tube Problems	1300-1350
Boiler Air and Gas Systems	1400-1599
Boiler Control Systems	1700-1799
Boiler Overhaul and Inspections	1800-1810
Boiler Water Condition	1850
Boiler Design Limitations	1900-1910
Boiler Miscellaneous	1999

Nuclear Reactor

Core/Fuel	2010-2090
Control Rods and Drives	2110-2160
Reactor Vessel and Internals	2170-2199
Reactor Coolant System	2200-2399
Steam Generators	2400-2599
Core Cooling/Safety Injection	2600-2649
Electrical Safety Systems	2650-2699
Containment System	2700-2799
Chemical and Volume Control/ Reactor Water Cleanup	2810-2819
Nuclear Cooling Water System	2820-2839
Auxiliary Systems	2840-2899
Miscellaneous Reactor Codes	2999

Balance of Plant

Condensing System	3110-3199
Circulating Water Systems	3210-3299
Condensate System	3310-3399
Feedwater System	3410-3499
Heater Drain Systems	3501-3509
Extraction Steam	3520-3529
Electrical	3600-3659
Auxiliary Systems	3810-3899
Miscellaneous Balance of Plant	3950-3999

Steam Turbine

High Pressure Turbine	4000-4099
Intermediate Pressure Turbine	4100-4199
Low Pressure Turbine	4200-4250
Valves	4260-4269
Piping	4270-4279
Lube Oil and Hydraulic System	4280-4299
Controls	4300-4309
Miscellaneous Steam Turbine Codes	4400-4499

Generators

Generator	4500-4580
Exciter	4600-4609
Cooling System	4610-4650
Controls	4700-4750
Miscellaneous Generator Codes	4800-4899

Gas Turbine/Jet Engine

Inlet Air System and Compressors	5000-5030
Fuel, Ignition and Combustion System	5040-5079
Turbines	5080-5099
Exhaust System	5100-5109
Auxiliary Systems	5110-5190
Miscellaneous	5200-5299

Diesel Engines

Engine	5700-5799
Engine Auxiliaries	5800-5849
Engine Controls	5850-5870
Miscellaneous	5890-5999

<u>Combined Cycle</u>	6000-6299

Hydro Turbine

Turbine	7000-7099
Water Supply/Discharge	7100-7199
Miscellaneous	7200-7299

<u>Expander Turbine</u>	7800-7960

Pollution Control Equipment

Wet Scrubbers	8000-8499
Dry Scrubbers	8500-8549
Precipitators	8550-8580
Miscellaneous	8600-8699

External

Catastrophe	9000-9040
Economic	9100-9150
Fuel Quality	9200-9290
Miscellaneous External Problems	9300-9320

Regulatory, Safety, Environmental

Regulatory	9500-9510
Stack Emission	9600-9650
Other Operating Environmental Limitations	9660-9690
Safety	9700-9720

<u>Personnel Errors</u>	9900-9920

BOILER

This set of codes contains the following:

- Boiler
- Boiler internals (tubes, refractory, supports, etc.)
- All the fuel handling, storage fuel preparation and burning equipment.
- The forced/induced draft air system.
- Slag and ash removal except for particulate and gas cleanup. These latter items are covered under pollution control equipment.
- The main steam and reheat steam systems up to but not including the turbine stop or isolation valves.
- The feedwater system downstream of the final valve prior to entry into the economizer or boiler.
- Boiler blowdown systems.
- The start up bypass system including drains up to the heaters or condenser.
- Boiler water chemistry problems not due to problems in the condensate/feedwater system, the chemical addition system, or the demineralizer/polisher system.
- The instruments and controls associated with the above equipment.

Boiler Fuel Supply

Coal Handling Equipment up Through Bunkers

0010	Thaw shed failure or fire
0020	Coal car dumpers, shakers, and unloaders
0030	Coal conveyers and feeders
0040	Coal elevators
0050	Coal storage fires
0060	Coal crushers including motors
0070	Coal samplers
0080	Stackers/reclaimers
0090	Bunker fires
0100	Bunker gates
0110	Other coal fuel supply problems up through bunkers

Pulverizers, Primary Air Fans and Associated Ducts

0200	Pulverizer fan (for indirect firing)
0210	Pulverizer air heater (for indirect firing)
0220	Pulverizer system cyclone separator
0230	Pulverizer bag filter
0240	Pulverized coal bin
0250	Pulverizer feeders
0260	Primary air fan/exhauster
0270	Primary air ducts and dampers

Pulverizers, Primary Air Fans and Associated Ducts, Cont.

0280 Pulverizer fires
0290 Pulverizer reduced capacity due to wear
0300 Pulverizer motors and drives
0310 Pulverizer mills
0320 Foreign object in mill
0330 Pulverizer coal leak
0340 Other pulverizer problems
0350 Pulverized fuel and air piping (from pulverizer to wind box)

Burners

0360 Burners
0370 Burner instruments and controls (except light-off)
0380 Light-off systems (including fuel supply)
0390 Burner wind boxes and dampers
0400 Burner wind box fires
0410 Other burner problems

Cyclone

0420 Cyclone crusher
0430 Cyclone furnace

Oil and Gas Systems (except light-off)

0440 Fuel oil pumps
0450 Fuel oil heaters
0460 Fuel oil atomizers
0470 Oil and gas fires
0480 Other oil and gas fuel supply problems (Note-use codes 0360-0410 for burner problems)

Boiler Piping System

Main Steam

0500 Main steam piping up to turbine stop valves
0510 Main steam relief/safety valves
0520 Other main steam valves (including vent and drain valves but not including the turbine stop valves)
0530 Other main steam system problems

Cold and Hot Reheat Steam

0540 Reheat steam piping up to turbine stop valves
0550 Reheat steam relief/safety valves
0560 Other reheat steam valves (not including turbine stop or intercept valves)
0570 Other reheat steam problems

Desuperheaters/Attemperatures

- 0580 Desuperheater/attemperator piping
- 0590 Desuperheater/attemperator valves
- 0600 Desuperheater/attemperator spray nozzles
- 0610 Desuperheater/attemperator drums
- 0620 Other desuperheater/attemperator problems

Startup Bypass

- 0630 Startup bypass system piping (including drain lines up to heaters or condenser)
- 0640 Startup bypass system valves
- 0650 Startup bypass tanks or flash tanks
- 0660 Other startup bypass system problems

Feedwater and Blowdown

- 0670 Feedwater piping downstream of feedwater regulating valve
- 0680 Feedwater valves (not feedwater regulating valve)
- 0690 Other feedwater problems downstream of feedwater regulating valve (See BOP Codes 3410 to 3490 for remainder of feedwater system)
- 0700 Blowdown system valves
- 0710 Blowdown system piping
- 0720 Blowdown system controls
- 0730 Other blowdown system problems

Boiler Recirculation

- 0740 Boiler recirculation pumps
- 0750 Boiler recirculation piping
- 0760 Boiler recirculation valves
- 0770 Other boiler recirculation problems

Miscellaneous Piping

- 0780 Headers between tube bundles
- 0799 Other piping system problems

Boiler Internals and Structures

- 0800 Drums and drum internals
- 0810 Boiler supports and structures (except tube supports - see Code 1320)
- 0820 Casing
- 0830 Doors
- 0840 Refractory and insulation
- 0850 Other internal or structural problems

Slag and Ash Removal

- 0860 Soot blowers air
- 0870 Soot blowers steam
- 0880 Fly ash handling (not precipitators, scrubbers, mechanical collectors, or baghouses)
- 0890 Bottom ash systems (wet or dry)
- 0900 Slag-tap (cyclone furnace)
- 0910 Slag-tap (other than cyclone furnace)
- 0920 Other slag and ash removal problems

Boiler Tube Leaks

- 1000 Furnace wall
- 1010 Cyclone furnace (in cyclone area only)
- 1020 Convection pass wall
- 1030 Boiler screen, wing wall or slag screen (water tubes only)
- 1040 First superheater
- 1050 Second superheater
- 1060 First reheater
- 1070 Second reheater
- 1080 Economizer
- 1090 Other tubes

Boiler Tube Fireside

Slagging or Fouling

- 1100 Furnace wall
- 1110 Cyclone furnace (in cyclone area only)
- 1120 Convection pass wall
- 1130 Boiler screen, wing wall, or slag screen (water tubes only)
- 1140 First superheater
- 1150 Second superheater
- 1160 First reheater
- 1170 Second reheater
- 1180 Economizer
- 1190 Other tubes
- For fouling or slagging due to unavailability of soot blowers or their air or steam supply, see codes 0860 and 0870.
- 1200 Operation at reduced power to avoid slagging or fouling (report power reductions for slag accumulation or slag removal using codes 1100 to 1190).

Miscellaneous Boiler Tube Problems

- 1300 Water side fouling
- 1310 Water side cleaning
- 1320 Tube supports/attachments
- 1330 Slag fall damage
- 1340 Tube modifications (including addition and removal of tubes)
- 1350 Other tube problems

Boiler Air and Gas Systems*

Air Supply

- 1400 Forced draft fans
- 1410 Forced draft fan motors
- 1420 Other forced draft fan problems
- 1430 Air supply ducts
- 1440 Air supply dampers
- 1450 Other air supply problems

Flue Gas

- 1460 Induced draft fan fouling
- 1470 Induced draft fan motors and drives
- 1480 Other induced draft fan problems
- 1490 Air preheater fouling
- 1500 Other air preheater problems
- 1510 Flue gas ducts (except recirculation)
- 1520 Flue gas dampers (except recirculation)
- 1530 Other flue gas problems

Recirculation

- 1540 Recirculation fan fouling
- 1550 Recirculation fan motors
- 1560 Other recirculation fan problems
- 1570 Recirculation ducts
- 1580 Recirculation dampers
- 1590 Stacks (Use Code 8430 for stack problems due to pollution control equipment)

Miscellaneous

- 1599 Other air and gas handling problems

Boiler Control Systems (including instruments which input to the controls)

- 1700 Feedwater controls (report local controls—feedwater pump, feedwater regulator valve, etc.,—with component or system)
- 1710 Combustion/steam condition controls (report local controls—burners, pulverizers, etc.,—with component or system)
- 1720 Desuperheater/atemperator controls
- 1730 Boiler explosion or implosion
- 1740 Gage glasses
- 1799 Other control problems

* Does not include burner pipes, wind boxes, primary air or pulverizer exhausters.

Boiler Overhaul and Inspections

- 1800 Boiler overhaul (use only for general overhaul items only, see General Information Page B-1)
- 1810 Boiler inspections

Boiler Water Condition

- 1850 Boiler water condition (not feedwater water quality)

Boiler Design Limitations

- 1900 Improper balance between tube sections not due to fouling or plugging
- 1910 Inadequate air not due to equipment problems

Boiler Miscellaneous

- 1999 Boiler, miscellaneous (use more specific code—other slagging and fouling problems, other control problems—whenever possible. All problems must be described in narrative.)

NUCLEAR REACTOR

This set of codes contains the following:

- The reactor
- The containment system
- The reactor coolant system including chemical, volume, and pressure control system
- Safety systems, both electrical and mechanical
- Residual heat removal systems
- Closed loop cooling water for reactor systems
- Service water for closed loop cooling and other reactor systems
- Steam generators
- Main steam systems up to the outboard containment isolation valve
- Feedwater systems from the reactor or steam generator up to the outboard containment isolation valve
- Blowdown systems
- Radioactive waste and off gas systems

Core/Fuel

2010	Fuel failure including high activity in RCS or offgas
2020	Control rod pattern changes and control rod repatch. (Preconditioning following a pattern change is to be reported in Code 2031.)
2021	Power limited by rod pattern. (If rod pattern is limited by fuel limits, use appropriate code below.)
2030	Fuel limits - peaking factors
2031	Fuel preconditioning
2032	Fuel limits - MCPR
2033	Fuel limits MAPLHGR
2034	Core tilt restrictions
2035	Core xenon restrictions
2036	End-of-life scram reactivity/rod worth restrictions
2037	Other fuel limits. (For core coastdown, conservation or stretch see Codes 9110 and 9120.)
2040	Core physics tests
2050	Burnable poison problems including poison curtains
2060	Excore nuclear instrumentation
2061	Incore nuclear instrumentation
2062	Other fuel/core related instrumentation problems

Core/Fuel, Cont.

- 2070 Normal refueling
- 2071 Refueling equipment problems
- 2090 Other core/fuel problems

Control Rods and Drives

- 2110 Control rod drive motors
- 2111 Control rod magnetic jack drives
- 2112 Control rod hydraulic drives
- 2120 Control rod scram mechanisms
- 2130 Control rod assemblies other than drive and scram mechanisms
- 2140 Control rod drive cooling
- 2150 Control rod instrumentation
- 2151 Control rod drive controls
- 2152 Control rod drive power supplies
- 2160 Other control rod drive problems

Reactor Vessel and Internals

- 2170 Reactor vessel flanges and seals
- 2171 Reactor vessel nozzles
- 2172 Feedwater spargers
- 2173 Jet pumps
- 2174 Core support
- 2175 Specimen holders
- 2176 Control rod guides (not in fuel)
- 2199 Other reactor vessel problems

Reactor Coolant System

Pumps

- 2200 Reactor coolant/recirculating pumps
- 2210 Reactor coolant/recirculating pump motors
- 2220 Reactor coolant recirculating pump MG sets

Piping

- 2230 Reactor coolant system piping
- 2240 Reactor coolant system pipe supports
- 2250 Reactor coolant system filters and strainers
- 2260 Reactor coolant flanges, fittings and manways.

Valves

- 2270 Power operated relief and safety/relief valves
- 2280 Nonpower operated safety valves
- 2290 Pressurizer spray valves
- 2300 Recirculation loop flow control valves
- 2320 Other reactor coolant valves (including RCS boundary valves in connected systems)

Instruments and Controls

- 2330 Pressurizer level instruments and controls
- 2340 Pressurizer pressure instruments and controls
- 2350 BWR feedwater controls
- 2360 BWR pressure controls
- 2370 Reactor trip system including sensors, logic and actuators (includes spurious trips but not valid trips)
- 2380 Reactor control system/integrated control system problems
- 2390 Other reactor coolant system instruments and controls

Miscellaneous

- 2399 Other reactor coolant system problems

Steam Generators and Steam System

- 2400 Steam generator tube leaks
- 2411 Steam generator tube inspections
- 2412 Steam generator tube supports
- 2420 Steam generator moisture separators and dryers
- 2421 Steam generator feedwater nozzles
- 2422 Other steam generator internals problems
- 2430 Steam generator shell
- 2431 Steam generator flanges, manways, and fittings
- 2432 Steam generator supports and snubbers
- 2440 Steam generator chemistry (excluding feedwater chemistry)
- 2441 Steam generator tube lancing
- 2442 Steam generator chemical cleaning
- 2443 Steam generator modifications
- 2450 Blowdown system piping
- 2460 Blowdown system valves
- 2470 Blowdown system instruments and controls
- 2480 Other blowdown system problems
- 2500 Steam piping (up to turbine stop valves and bypass valves)
- 2510 Main steam isolation valves (BWR and PWR)
- 2520 Main steam safety/relief valves (except BWR)
- 2530 Atmospheric or condenser dump valves (not SRVs)

Steam Generators and Steam System, Cont.

- 2540 Other steam valves
- 2550 Steam generator instruments (including piping and valves), (No RPS or SAS inputs.)
- 2560 Steam generator controls
- 2599 Other steam generator problems

Core Cooling/Safety Injection *

- 2600 High pressure safety injection core injection or core spray pumps (including RCIC)
- 2601 Motors for high pressure pumps
- 2602 Steam turbine drives for high pressure pumps (including RCIC)
- 2603 High pressure piping
- 2604 High pressure valves
- 2609 Other high pressure injection problems

- 2620 Low pressure safety injection core spray or decay heat pumps
- 2621 Motors for low pressure pumps
- 2622 Low pressure piping
- 2623 Low pressure valves
- 2624 Low pressure heat exchangers
- 2625 Accumulators (up to and including check valves)
- 2629 Other low pressure problems

- 2630 Safeguard actuation system (including sensors, logic, activators, and sequencers)

- 2649 Other emergency core cooling/residual heat removal system problems.

Electrical Safety Systems

- 2650 Emergency diesel generators (including actuating systems)
- 2651 Emergency diesel generator output breakers
- 2660 Safeguards buses and associated equipment (transformers, breakers, etc.)
- 2670 DC safety system power supplies
- 2680 120V AC safety system power supplies (including inverters)
- 2699 Other electrical safety system power supplies. (For nonsafety electrical systems, see Codes 3600 to 3659.)

* Where portions of these systems also serve in the makeup system, report problems on those portions of the system with the CVCS.

Containment System

- 2700 Containment structure
- 2701 Containment liner
- 2702 Containment hatches
- 2703 Containment penetrations

- 2720 Containment isolation valves and dampers
- 2730 Containment isolation actuation
- 2740 Containment penetration pressurization system
- 2750 Containment hydrogen control system (vents, recombiners, etc.)
- 2760 Containment spray system (including actuation)
- 2770 Containment cooler/filter systems

- 2780 Containment testing

- 2799 Other containment system problems

Chemical and Volume Control/Reactor Water Cleanup

- 2810 Makeup pumps
- 2811 Boric acid transfer pumps
- 2812 Tanks
- 2813 Demineralizers
- 2814 Filters
- 2815 Heat exchangers
- 2816 Valves and piping
- 2817 Instruments and controls
- 2819 Other CVCS and RWC problems

Nuclear Cooling Water Systems

- 2820 Nuclear closed cooling water pumps
- 2821 Nuclear closed cooling water piping
- 2822 Nuclear closed cooling water valves
- 2823 Nuclear closed cooling heat exchanger
- 2829 Other closed cooling water system problems

- 2830 Nuclear service water pumps
- 2831 Nuclear service water piping
- 2832 Nuclear service water valves
- 2833 Nuclear service water heat exchangers
- 2839 Other service water problems

Auxiliary Systems

- 2840 Auxiliary feedwater pumps
- 2841 Auxiliary feedwater pump motors
- 2842 Auxiliary feedwater pump steam turbines (including steam control valves)

Auxiliary Systems, Cont.

- 2843 Auxiliary feedwater piping
- 2844 Auxiliary feedwater valves
- 2849 Other auxiliary feedwater problems

- 2870 Radioactive liquid waste system problems

- 2880 Radioactive gas and waste system problems
- 2890 Condenser offgas system problems

- See Codes 3000 to 3999 for other auxiliary systems.

Miscellaneous Reactor Codes

- 2999 Other nuclear reactor problems

BALANCE OF PLANT

The electrical codes in this set apply to all units. The remainder of the codes in this set apply primarily to steam generating units and encompass those equipment items not included in the Boiler or Nuclear Reactor groups with the exception of the steam turbine and the generator.

Condensing System

Condenser Tubes

- 3110 Condenser tube leaks
- 3111 Condenser tube fouling shell side
- 3112 Condenser tube fouling tube side
- 3113 Condenser tube and water box cleaning (including circulating water flow reversal)
- 3119 Other condenser tube problems

Condenser Casing or Shell and Internals

- 3120 Tube sheets
- 3121 Expansion joint
- 3122 Gaskets and seals
- 3123 Hot well
- 3129 Other condenser casing or shell and internal problems

Vacuum Equipment

- 3130 Air Ejectors
- 3131 Air ejector piping and valves
- 3132 Inter and after condensers
- 3133 Vacuum pumps
- 3134 Vacuum pump piping and valves
- 3149 Loss of vacuum not attributable to a particular component such as air ejectors or valves. Also high back pressure not attributable to high circulating water temperature or vacuum losses from a known cause.

Condenser Controls

- 3150 Hot well level controls
- 3151 Vacuum pump and air ejector controls
- 3159 Other condensing system controls and instruments

Miscellaneous

- 3170 Condenser inspection. (Report looking for tube leaks in Code 3110.)
- 3199 Other condensing system problems

Circulating Water Systems

- 3210 Circulating water pumps and motors
- 3220 Circulating water piping
- 3230 Circulating water valves
- 3240 Cooling tower fans
- 3241 Cooling tower efficiency below design
- 3242 Cooling tower fill damage
- 3243 Cooling tower icing
- 3244 Cooling tower fires
- 3245 Other cooling tower problems
- 3250 Circulating water system instruments and controls
- 3260 Traveling screens
- 3270 Intake system problems other than traveling screens
- 3280 High circulating water temperature. (Not seasonal, not tower efficiency below design and not some other listed equipment problem.)
- 3285 Circulating water chemistry
- 3299 Other circulating water system problems

Condensate System

Pumps, Piping, and Valves

- 3310 Condensate/hotwell pumps
- 3311 Condensate/hotwell pump motor
- 3312 Booster pumps
- 3313 Booster pump motors
- 3320 Condensate piping
- 3330 Condensate valves

Low/Intermediate Pressure Heater and Deaerators

- 3340 LP heater tube leaks
- 3341 LP heater other
- 3342 IP heater tube leaks
- 3343 IP heater other
- 3344 Deaerator (including level control)

Polishers/Chemical Addition

- 3350 Condensate polishing and filtering systems
- 3351 Chemical addition systems
- 3352 Feedwater chemistry (not specific to condenser, polishers, or chemical addition)

Miscellaneous

- 3360 Condensate makeup and return (including storage tanks)
- 3370 Condensate system controls and instrumentation (no hotwell level, heater level, or deaerator level controls)
- 3380 Condensate Coolers
- 3399 Other condensate system problems

Feedwater System (Does not include extraction or drain systems)

- 3410 Feedwater pump
- 3411 Feedwater pump motor
- 3412 Feedwater pump steam turbine
- 3413 Feedwater pump coupling and drive shaft
- 3414 Feedwater pump local controls
- 3415 Feedwater pump/drive lube oil system
- 3416 Other feedwater pump problems
- 3420 Feedwater piping
- 3430 Feedwater regulating (boiler level control) valve
- 3431 Other feedwater valves
- 3440 High pressure heater tube leaks
- 3441 Other high pressure heater problems (see condensate system for LP and IP heater codes)
- 3499 Other feedwater system problems

Heater Drain Systems

- 3501 Heater drain pumps
- 3502 Heater level control
- 3503 Heater drain piping
- 3504 Heater drain valves
- 3509 Other heater drain system problems

Extraction Steam

- 3520 Extraction steam piping
- 3521 Extraction steam valves
- 3522 Extraction steam instruments and controls
- 3529 Other extraction steam system problems

Electrical (Does not include nuclear safety (Class 1E) systems)

- 3600 Switchyard transformers and associated cooling systems
  - 3611 Switchyard circuit breakers
  - 3612 Switchyard system protection devices
  - 3619 Other switchyard equipment

  - 3620 Main transformer
  - 3621 Station service transformer
  - 3622 Startup transformer
  - 3623 Auxiliary generators (except nuclear emergency generators)
  - 3629 Other switchyard or high voltage system problems

  - 3630 480-volt transformers
  - 3631 480-volt circuit breakers
  - 3632 480-volt conductors and buses
  - 3633 480-volt insulators
  - 3634 480-volt protection devices
  - 3639 Other 480-volt problems

  - 3640 AC instrument power transformers
  - 3641 Circuit breakers
  - 3642 Conductors and buses
  - 3643 Inverters
  - 3644 Protection devices
  - 3649 Other AC instrument power problems

  - 3650 DC instrument power battery chargers
  - 3651 DC circuit breakers
  - 3652 DC conductors and buses
  - 3653 DC protection devices
  - 3659 Other DC power problems
3660	Use	3670	Use
3661	These	3671	These
3662	Codes	3672	Codes
3663	for	3673	for
3664	4160v	3674	12KV
3669	System	3679	System

Auxiliary Systems (Not including nuclear safety grade auxiliaries)

Service Water

- 3810 Service water pumps and motors
- 3811 Service water piping
- 3812 Service water valves
- 3813 Service water heat exchangers
- 3819 Other service water problems

Closed Cooling Water Systems

- 3820 Closed cooling water pumps
- 3821 Closed cooling water piping
- 3822 Closed cooling water valves
- 3823 Closed cooling water heat exchangers
- 3829 Other closed cooling water system problems

Auxiliary Steam

- 3830 Auxiliary boiler
- 3831 Auxiliary steam piping
- 3832 Auxiliary steam valves
- 3833 Auxiliary steam controls and instruments
- 3839 Other auxiliary steam problems. (See also extraction steam Codes 3520 to 3529; startup bypass system Codes 0630 to 0660; and soot blower steam Code 0870.)

Service Air

- 3840 Service air compressors
- 3841 Service air piping
- 3842 Service air valves
- 3843 Service air dryers
- 3849 Other service air problems. (See soot blower air Code 0860.)

Instrument Air

- 3850 Instrument air compressors
- 3851 Instrument air piping
- 3852 Instrument air valves
- 3853 Instrument air dryers
- 3854 N₂ backup to instrument air
- 3859 Other instrument air problems

Fire Protection System

- 3860 Fire protection system pumps
- 3861 Fire protection system piping
- 3862 Fire protection system valves
- 3869 Other fire protection system problems

Miscellaneous

- 3899 Other auxiliary system problems

Miscellaneous Balance of Plant

- 3950 Process computer
- 3960 Thermal derating (thermal efficiency losses in balance of plant when specific cause(s) unknown)
- 3999 Other balance of plant problems

STEAM TURBINE

Besides the turbine, this set includes the steam stop/control valves, the turbine control system and the turbine auxiliaries. Note that the extraction steam codes are contained in the Balance of Plant set of codes.

High Pressure Turbine

4000	Outer casing
4001	Inner casing
4010	Nozzles, nozzle blacks, and bolting
4011	Diaphragms
4012	Blades
4013	Diaphragms unit and shroud type
4020	Shaft seals
4021	Dummy rings
4022	Gland rings
4030	Rotor shaft
4040	Bearings
4099	Other high pressure turbine problems

Intermediate Pressure Turbine

4100	Outer casing
4101	Inner casing
4110	Nozzles, nozzle blocks and bolting
4111	Diaphragms
4112	Blades
4120	Shaft seals
4121	Dummy rings
4122	Gland rings
4130	Rotor shaft
4140	Bearings
4199	Other intermediate pressure turbine problems

Low Pressure Turbine

4200	Outer casing
4201	Inner casing

Low Pressure Turbine, Cont.

- 4210 Nozzles, nozzle blocks and bolting
- 4211 Diaphragms
- 4212 Blades

- 4220 Shaft seals
- 4221 Dummy rings
- 4222 Gland rings

- 4230 Rotor shaft

- 4240 Bearings

- 4250 Other low pressure turbine problems

Valves

- 4260 Main stop valves
- 4261 Control valves
- 4262 Intercept valves
- 4263 Reheat stop valves
- 4264 Combined intercept valves
- 4265 Miscellaneous drain and vent valves
- 4269 Other turbine valves

Piping

- 4270 Crossover or under piping
- 4279 Miscellaneous turbine piping

Lube Oil and Hydraulic System (Do not include bearing failures due to lube oil)

- 4280 Lube oil pumps
- 4281 Lube oil coolers
- 4282 Lube oil conditioners
- 4283 Lube oil system valves and piping
- 4289 Other lube oil system problems

- 4290 Hydraulic system pumps
- 4291 Hydraulic system coolers
- 4292 Hydraulic system filters
- 4293 Hydraulic system pipes and valves
- 4299 Other hydraulic system problems

Controls

- 4300 Turbine supervisory system. (Use Codes 4290 to 4299 for hydraulic oil.)
- 4301 Turbine governing system

Controls, cont.

- 4302 Turbine trip devices (including instruments)
- 4303 Exhaust hood and spray controls
- 4309 Other turbine instrument and control problems

Miscellaneous Steam Turbine Codes

- 4400 Major turbine overhaul. (General overhaul items only; see General Information, page B-1.)
- 4401 Inspection
- 4410 Turning gear and motor
- 4420 Vibration of the turbine generator unit that cannot be attributed to a specific cause such as bearings or blades (including balance moves)
- 4430 Gland seal system
- 4440 Moisture separator/reheater (nuclear including MSR drains controls, etc.)
- 4450 Water induction
- 4460 Turbine overspeed trip test
- 4499 Other steam turbine problems

GENERATORS

This set of codes contains the generator, exciter, the generator cooling systems, and generator controls. Note that the main leads up to and including the generator output breaker are included in this set of codes.

Generator

- 4500 Rotor windings
- 4510 Rotor collector rings
- 4520 Stator windings, bushes, and terminals
- 4530 Stator core iron
- 4540 Brushes and brush rigging
- 4550 Generator bearings and lube oil system
- 4560 Generator vibration (not including vibration due to failed bearing and other components)
- 4570 Generator casing
- 4580 Generator end bells and bolting

Exciter

- 4600 Exciter motor
- 4601 Exciter field rheostat
- 4602 Exciter commutator and brushes
- 4609 Other exciter problems

Cooling System (Report failures caused by water leaks into generator as Codes 4500, 4510, etc.)

- 4610 Hydrogen cooling system piping and valves
- 4611 Hydrogen coolers
- 4612 Hydrogen storage system
- 4613 Hydrogen seals
- 4619 Other hydrogen system problems
- 4620 Air cooling system
- 4630 Liquid cooling system
- 4640 Seal oil system and seals
- 4650 Other cooling system problems

Controls

- 4700 Generator voltage control
- 4710 Generator metering devices
- 4720 Generator synchronization equipment
- 4730 Generator current and potential transformers
- 4740 Emergency generator trip devices
- 4750 Other generator controls and metering problems

Miscellaneous Generator Codes

- 4800 Generator main leads
- 4810 Generator output breaker
- 4830 Major overhaul. (General overhaul items only; see General Information, page B-1.)
- 4840 Inspection
- 4899 Other generator problems

GAS TURBINE/JET ENGINE

In addition to the codes in this set, gas turbine/jet engine units are to use the Generator and Balance of Plant electrical codes to report equipment problems.

Inlet Air System and Compressors (use HP compressor if only one)

Ducts and Filters

- 5000 Inlet air ducts
- 5001 Inlet air vanes
- 5002 Inlet air filters
- 5003 Inlet cone
- 5009 Other inlet air problems

Compressors

- 5010 High pressure shaft
- 5011 High pressure bearings
- 5012 High pressure blades/buckets
- 5019 Other high pressure problems
- 5020 Low pressure shaft
- 5021 Low pressure bearings
- 5022 Low pressure blades/buckets
- 5029 Other low pressure problems
- 5030 Super charging fans

Fuel, Ignition, and Combustion Systems

- 5040 Fuel tanks
- 5041 Fuel piping and valves
- 5042 Fuel nozzles
- 5049 Other fuel system problems
- 5050 Ignition system
- 5060 Atomizing air system
- 5070 Combustor casing
- 5071 Combustor liner
- 5072 Combustor caps
- 5079 Other combustor problems

Turbines (use HP if only one)

- 5080 High pressure shaft
- 5081 High pressure bearings

Turbines, Cont.

- 5082 High pressure blades/buckets
- 5083 High pressure nozzles
- 5084 High pressure casing/expansion joints
- 5085 Interstage gas passages
- 5086 High pressure shaft seals
- 5089 Other high pressure problems

- 5090 Low pressure shaft
- 5091 Low pressure bearings
- 5092 Low pressure blades/buckets
- 5093 Low pressure nozzles
- 5094 Low pressure casing/expansion joints
- 5095 Interstage gas passages
- 5096 Low pressure shaft seals
- 5097 Other low pressure problems
- 5099 HP to LP coupling

Exhaust System

- 5100 Chamber
- 5101 Hoods
- 5102 Vanes
- 5103 Silencer
- 5104 Cones
- 5109 Other exhaust problems (including high exhaust temperature not attributable to a specific problem)

Auxiliary Systems

- 5110 Lube oil
- 5120 Hydraulic oil
- 5130 Starting system
- 5140 Battery and charger
- 5150 Turning gear and motor
- 5160 Cooling and seal air
- 5170 Cooling water
- 5180 Anti-icing system
- 5190 Other auxiliary system problems

Miscellaneous

- 5200 Reduction gear
- 5201 Load shaft and bearings
- 5210 Intercoolers
- 5220 Regenerators
- 5230 Heat shields
- 5240 Fire detection and extinction.
- 5241 Fire in unit
- 5250 Controls and instruments
- 5260 Major overhaul. (General overhaul items only; see General Information, page B-1.)
- 5261 Engine cleaning
- 5262 Engine exchange
- 5270 Inspection
- 5280 Vibration in unit not attributable to bearings or other components
- 5299 Other combustion turbine/jet engine problems

DIESEL ENGINES

In addition to the codes in this set, diesel engine units are to use the Generator and Balance of Plant electrical codes to report equipment problems.

Engine

- 5700 Drive shaft and bearings
- 5710 Cylinders
- 5711 Cylinder heads
- 5712 Hydraulic lock (water in cylinders)
- 5720 Pistons
- 5730 Intake valves
- 5731 Exhaust valves
- 5740 Turbo Charger
- 5790 Vibration
- 5799 Other engine problems

Engine Auxiliaries

- 5800 Lube oil system
- 5805 Cooling system
- 5810 Heater elements
- 5815 Fuel system
- 5820 Start system
- 5825 Battery and battery charger system
- 5830 Air filter system
- 5849 Other engine auxiliary problems

Engine Controls

- 5850 Governor
- 5855 Engine control system
- 5860 Control power transformer
- 5865 Synchronization system
- 5870 Other engine control problems

Miscellaneous

- 5890 Major overhaul. (General overhaul items only; see General Information,
-page B-1.)
- 5895 Inspection
- 5999 Other diesel engine problems

COMBINED CYCLE*

Gas Turbine

— See Codes 5000 to 5290 for gas turbine

Heat Recovery Steam Generator

6000 Heat recovery steam generator to gas turbine connecting equipment. See Codes 0010 to 1999 for Boiler codes.

Steam Turbine

6100 Steam turbine to gas turbine coupling. See Codes 4000 to 4499 for steam turbine codes.

Generator

— See Codes 4500 to 4899 for generator codes. If separate steam and gas turbine generators exist, note in the narrative which generator is affected.

Balance of Plant

— See Codes 3000 to 3999 for Balance of Plant systems (condensate, feedwater, etc.)

Instruments and Controls

6200 Combined cycle instruments and controls. (Instruments and controls specific to the gas turbine, steam turbine, boiler, generator, or balance of plant are to be reported using the codes for the appropriate piece of equipment.)

*When problems in one component cause deratings of another component, as when the loss of a gas turbine derates a heat recovery boiler, the total derating of the unit is to be reported as due to the one problem.

Miscellaneous

6299 Other combined cycle problems, (Use other gas turbine problem codes, other steam turbine codes, etc., whenever appropriate.)

HYDRO TURBINE

In addition to the codes contained in this set, hydro and pumped storage units are to use the Generator and Balance of Plant electrical codes to report equipment problems.

Turbine

- 7000 Shaft
- 7001 Shaft packing
- 7002 Oil lubricated bearings
- 7003 Lube oil system. (Report bearing failures due to lube oil problems in Code 7002.)
- 7004 Water lubricated bearings
- 7010 Runner cavitation damage
- 7011 Other runner problems
- 7012 Casing, wear ring or liner cavitation damage
- 7020 Nozzle assembly
- 7030 Vibration. (Only for unbalance, report bearing failure, etc., in appropriate category.)
- 7040 Turbine overhaul
- 7050 Turbine governor hydraulic
- 7051 Turbine governor electrohydraulic
- 7052 Other turbine controls. (Report specific wicket gate controls, etc., using the code for the appropriate equipment item.)
- 7099 Other turbine problems

Water Supply/Discharge

- 7100 Upper reservoir dams and dikes
- 7101 Lower reservoir dams and dikes
- 7102 Auxiliary reservoir dams and dikes
- 7110 Intake channel or flume (including trash racks)
- 7111 Intake tunnel
- 7120 Headgates
- 7121 Butterfly shutoff valves
- 7122 Spherical shutoff valves
- 7123 Spherical shutoff valve bypass line and valve
- 7124 Penstock
- 7130 Spiral case
- 7140 Wicket gate assembly

Water Supply/Discharge, Cont.

- 7141 Wicket gate operating mechanism or positioner
- 7150 Stay vanes
- 7160 Pressure regulating valve
- 7161 Pressure regulating valve operator or positioner
- 7162 Relief valve and vacuum breakers
- 7170 Draft tube
- 7180 Tailrace
- 7181 Tail water depressing equipment
- 7190 Dewatering and rewatering equipment
- 7191 Equalizing line
- 7199 Other water supply/discharge problems

Miscellaneous

- 7200 Major overhaul. (General overhaul items only; see General Information, page B-1)
- 7201 Inspection
- 7210 Canals (including siphons, radial gates, and spills)
- 7220 Unit out of service due to common penstock with unit under repair
- 7299 Other hydro problems. (Use Generator codes and Balance of Plant electrical and auxiliary codes as appropriate.)

EXPANDER TURBINE

7800	Couplings
7810	Shaft
7820	Bearings
7830	Blades
7840	Discs
7850	Spacers
7860	Nozzles
7870	Heat shields
7880	Exhaust diffusers
7890	Seal oil system and seals
7900	Inner casing
7910	Outer exhaust casing
7920	Lube oil system
7930	Control and instrumentation
7940	Evactor
7950	Major overhaul
7960	Other expander turbine problems

POLLUTION CONTROL EQUIPMENT*

This set of codes is to be used to report problems with flue gas desulphurization equipment and stack gas particulate removal equipment. If stack emission limits cause outages or deratings due to reasons other than equipment problems, use the Regulatory, Safety, Environmental stack emission codes.

Wet Scrubbers

Chemical supply

8000	Chemical feed storage, mill feeders and conveyors
8010	Crushers/mills
8020	Mill slurry tanks including agitators
8030	Classifiers
8040	Slurry transfer pumps
8050	Chemical unavailability
8099	Other chemical supply problems

Scrubber

8100	Scrubber/absorber tower
8110	Spray nozzles
8120	Spray pumps
8130	Recirculation tanks including agitators
8140	Reaction tanks including agitators
8150	Tubes
8160	Mist eliminators/demisters and washdown
8199	Other scrubber problems

Piping, Ducting, Dampers, and Fans

8200	Piping
8210	Valves
8220	Strainers or filters
8230	Ducting
8240	Bypass dampers
8250	Dampers other than bypass
8260	ID fans specific to the scrubber
8270	FD fans specific to the scrubber
8299	Other piping, ducting, damper, and fan problems

* Use Code 9510 for outages or deratings required to install pollution control equipment. Use Codes 9600 to 9650 only if no pollution control equipment problems are responsible for exceeding emission limits.

Waste Disposal and Recovery

- 8300 Waste disposal/recovery tanks
- 8310 Waste disposal/recovery pumps
- 8320 Waste disposal ponds
- 8330 Dewatering equipment (thickener, centrifuge, etc.)
- 8349 Other waste disposal and recovery problems

Miscellaneous

- 8400 Scrubber gas discharge reheaters
- 8410 Scrubber instruments and controls
- 8420 Heat tracer
- 8430 Stack damage related to scrubber system
- 8440 Major overhaul
- 8450 Inspection
- 8460 Testing
- 8499 Other wet scrubber problems

Dry Scrubbers

- 8500 Solution feed tanks
- 8510 Solution mixers
- 8520 Solution feed pumps
- 8530 Spray towers
- 8540 Waste disposal
- 8549 Other dry scrubber problems

Precipitators

- 8550 Electrostatic precipitator fouling
- 8560 Electrostatic precipitator problems
- 8570 Mechanical precipitator fouling
- 8580 Mechanical collecting systems problems

*NOTE: Additional
Precipitator Codes
to be Added*

Miscellaneous

- 8600 Flue gas additives (furnace injection)
- 8650 Bag house systems
- 8670 Emission monitors
- 8699 Other pollution control problems

EXTERNAL

This set of codes is to be used for outages or deratings caused by external factors (flood, lightning, etc); economic factors (lack of fuel, labor strikes, etc.); operator training; and transmission system problems external to the plant.

Catastrophe

9000	Flood
9010	Fire, not related to a specific component
9020	Lightning
9030	Earthquake
9040	Other catastrophe

Economic

9110	Core coastdown (nuclear)
9120	Core conservation (nuclear)
9130	Lack of fuel
9140	Plant modifications to burn different fuel that are not regulatory mandate
9150	Labor strikes
9160	Other Economic problems

Fuel Quality*

9200	High ash content
9210	Low grindability
9220	High sulfur content
9230	High vanadium content
9240	High sodium content
9250	Low BTU coal
9260	Low BTU oil
9270	Wet coal
9280	Frozen coal
9290	Other fuel quality problems

Miscellaneous External Problems

9300	Transmission system problems other than catastrophies. (Do not include switchyard problems in this category; see Codes 3600 to 3629.)
9310	Operator training
9320	Other external problems

* Use Codes 9600 to 9650 if the fuel quality results in exceeding stack emissions through no fault in the pollution control equipment. Fouling and slagging are to be reported using the appropriate equipment codes.

REGULATORY, SAFETY, ENVIRONMENTAL*

This set of codes is to be used solely for nonequipment related outages and deratings. Regulatory required inspections are to be reported using the appropriate equipment codes, and the fact that it was a regulatory requirement is to be noted in the narrative.

Regulatory

- 9500 Regulatory proceedings and hearings
- 9510 Plant modifications strictly for compliance with new or changed regulatory requirements (scrubbers, cooling towers, etc.)
- 9590 Miscellaneous Regulatory (this code is primarily intended for use with event Contribution Code 2 to indicate that a regulatory related factor contributed to the primary cause of the event.)

Stack Emission (Include exhaust emissions)

- 9600 SO₂ stack emissions
- 9610 NO_x stack emissions
- 9620 Particulate stack emissions
- 9630 Opacity
- 9650 Other stack or exhaust emissions

Other Operating Environmental Limitations

- 9660 Thermal discharge limits
- 9670 Noise limits (not for personnel safety)
- 9680 Fish kill
- 9690 Other miscellaneous operational environmental limits

Safety

- 9700 OSHA
- 9710 Nuclear Safety problems
- 9720 Other safety problems

* Use these codes only for outages or deratings not directly attributable to equipment failures.

PERSONNEL ERRORS

9900 Operator error
9910 Maintenance error
9920 Contractor error

APPENDIX B

ESTABLISHING THE ROOT CAUSE FOR LOSSES IN PLANT OR EQUIPMENT AVAILABILITY

APPENDIX B

ESTABLISHING THE ROOT CAUSE FOR LOSSES IN PLANT OR EQUIPMENT AVAILABILITY

This Appendix briefly describes a method for establishing the "root cause" of problems that result in losses in plant or equipment availability. It describes one of several methods that can be used for organizing an investigation to pinpoint the cause of equipment failures. Without detailed analysis of plant incidents that result in equipment outages and/or lost productivity, a data base cannot be accurately established. Lack of an adequate data base or input of incorrect information into the data base makes it impossible to perform meaningful evaluations of improvement projects.

DEFINITIONS USED IN ROOT CAUSE DEVELOPMENT

Cause of Failure Diagram - A graphic illustration used to track a loss of function to its root cause area; i.e., a road map for conducting an investigation.

Root Cause - The most fundamental cause of a problem without which loss of availability would not have occurred; once eliminated, the loss of availability will not reoccur in subsequent plant operation.

Root Cause Areas - Functional areas in which the root causes are found; namely, design, manufacturing, installation, etc.

Logic Tree Diagram - A series of questions representing the details of the functional areas to be investigated in establishing the root cause.

CONDUCTING A "ROOT CAUSE" INVESTIGATION

Because of the complex nature of power plants, the identification of real versus apparent causes of losses in availability and/or equipment failures are often difficult to establish. In order to establish a factual data base, it is necessary to identify "root causes" for plant events that result in lost availability. In order to expedite this type of analysis, an investigative format is needed. Such a format serves several purposes, such as:

- ° Providing a method for organizing outage information;
- ° Providing a visual checklist to ensure that all pertinent areas are thoroughly studied;
- ° Providing a standardized approach for conducting such a problem investigation;
- ° Preventing preconceived notions and bias from influencing the outcome of the study.

To conduct an investigation using this approach, two different tools have been developed:

- ° The cause of failure diagram, and
- ° The logic tree diagram.

Each helps to streamline an investigation and establish the root cause of the plant event that resulted in lost availability.

THE CAUSE OF FAILURE DIAGRAM

The cause of failure diagram is a graphic representation of the loss of function -- apparent cause of failure relationship, tracing a plant or equipment problem to its root cause. Although developed in this presentation for equipment failures, the same general procedures can be used for losses in plant availability resulting from human errors, regulatory restrictions, or restrictive operating procedures. For an equipment failure, the cause of failure diagram is developed to identify the loss of function, determine the failed systems, define the major system components, and establish the apparent cause of the failure. The identification of the root cause problem is an extension of this diagram using logic trees to direct the root cause investigation.

CONSTRUCTION OF THE CAUSE OF FAILURE DIAGRAM

As shown in Figure 21, the cause of failure diagram consists of two major portions:

- ° Identification of the failed component or part causing the equipment outage;
- ° Establishing the root cause of the failure.

CAUSE OF FAILURE DIAGRAM

Figure 21

The first six steps of the procedure are aimed at correctly identifying the single part or combination of parts that caused the outage. The remaining four steps detail the cause of failure so that actions can be taken to prevent the problem from reoccurring.

- STEP 1 (Identify Loss of Function)

The first step in the development of the cause of failure diagram is to correctly identify the loss of function that results from the problem under study. This might be, for example, the loss of ability to supply fuel oil to a boiler at a sufficient rate to meet steam demand. Such a loss would most likely result in a reduced firing rate of the boiler and less than full load output from the plant. For all plant outages or other problems, it is important as a first step in this procedure to correctly identify which of the various plant functions have been interrupted by the problem.

- STEP 2 (Determine Failed System)

Having identified the function that has been interrupted, the next step is to correctly identify the system causing the problem. This might be, for the example given in this presentation, the fuel delivery system.

- STEP 3 (Identify Major Components of the Failed System)

All the important components of the failed system should be identified and listed as suspect of causing the loss of function.

- STEP 4 (Define Loss of Function Characteristics for Major Components)

Having identified the major components of the failed system in Step 3, each component's loss of function on the operation of the system should be studied. Design and operation information should show the effect of losing a single pump in a parallel pumping array; i.e., reduction of flow, loss of pressure, etc. Knowing the effect of each component on the system's operation should allow for identification of the failed component.

- STEP 5 (Identify Failed Component)

Performing Steps 1-4 as well as examining any physical evidence, if present, should allow for identification of the failed component.

- STEP 6 (Identify Failed Part)

While equipment and its major components fail functionally, it is the component's parts that usually exhibit the evidence of failure. This evidence can usually be confirmed in the plant by examination of the various parts; i.e., warped pump shaft, cracked seal, etc. Often visual examination is enough to determine the part that is responsible for the loss of function. This does not imply that only one part is solely the cause of failure. Related, and in some instances even unrelated, parts should be suspect. In any case, all the parts of the failed component should be carefully examined for abnormalities that might be related to the failure.

- STEP 7 (Establish Mode of Failure)

The modes of failure of the part or parts identified in Step 6 should be determined; i.e., bending, cracking, buckling, spalling, etc. The failure mode can usually be determined by visual inspection and physical measurements of the failed part. Sometimes a laboratory study is needed to correctly establish this parameter.

- STEP 8 (Establish Mechanism of Failure)

To identify the mechanism that caused the failure (stress concentration, thermal loading, corrosion, impact, etc.), a laboratory analysis is often needed. Sometimes, however, experienced maintenance personnel are able to see physical evidence, such as a shaft discoloration, that quickly leads to establishing the mechanism that caused the part to fail.

- STEP 9 (Establish the Apparent Cause of Failure)

Laboratory analysis and physical evidence seen upon component disassembly usually indicates the apparent cause of failure -- lack of cooling, lack of lubrication, inadequate supporting, etc. Sometimes more than one apparent cause is found. They should all be listed for further study.

● STEP 10 (Establish Root Cause of Failure)

After completing Step 9 - establishing the apparent cause of failure, many investigators stop, feeling that correcting the apparent cause will prevent further losses of component availability. For some problems, this is true; but for others, more study is needed. For the example discussed here, one should be aware that although lack of lubrication may be an apparent cause of the problem, it is not the root cause. If one were to put a new shaft in the pump and lubricate it, it might still fail in future operation. What must be found is why the pump was without lubrication. Was the pump without lubrication because:

- No grease fittings were provided?
- Improper maintenance procedures were being followed?
- Improper servicing of the pump resulted from lack of training of maintenance personnel?

These are potential root causes, and it is corrective actions at this level that will solve the problem on a long-term basis.

The last step in conducting this investigation is establishing the root cause of the apparent problem. Figure 22 shows nine areas that contain the root cause for nearly all problems that are encountered in the operation of power plant equipment. Each area must be sequentially investigated until such time it becomes obvious that the root cause is not present within the area under consideration.

LOGIC TREE APPROACH TO ROOT CAUSE ANALYSIS

To conduct an investigation of the nine root cause areas, the logic tree approach is recommended. This method consists of using a series of question trees which diagrammatically represent the functional areas to be investigated. Using information developed in establishing the apparent cause of the failure (Step 9), the number of functional areas to be investigated can usually be minimized. Only those areas pertinent to the specific problem being analyzed need to be explored in detail. However, until such time as the investigator can definitely rule out one of the nine root cause areas, he

FUNDAMENTAL ROOT CAUSE AREAS

Figure 22

should proceed to study it as a potential candidate for containing the root cause. While this process increases the amount of detail involved in conducting a root cause investigation, it minimizes the possibility of overlooking less obvious contributing causes that are important if reoccurrence of the problem is to be prevented.

The logic trees consist of a series of charts representing functional areas to be studied in performing the root cause analysis. The charts are general in nature and are designed to guide the investigation -- preventing it from being haphazard and subject of guesses and bias. In some cases their detail is too extensive; while for other investigations, added detail will be needed as the study proceeds. Not every pertinent item to be considered can be listed in a chart of this type. The listings serve only as a guide or outline to be simplified or expanded as the specific needs of the study warrant.

It is not practical to show in this handbook the details of the logic trees that have been developed for the various functional areas. It is, however, worthwhile to examine one area in at least limited detail to illustrate the development of the logic trees and the types of questions they contain. Considering the design area, the following major subdivisions are used:

- Origin;
- User's inputs prior to design;
- Equipment specifications;
- Constraints on design;
- Design analysis.

Each area is expanded into a logic tree chart illustrating functional areas to be explored with qualified personnel familiar with the design of the equipment under study. As an example, Figure 23 shows the questioning process associated with establishing the details of the origin of the design. In investigating the previously given pump problem, one should explore with the manufacturer the history of the pump design. If this design is not a first-of-a-kind and is being used successfully in similar applications at other locations, it is not necessary to conduct this area of the investigation to great depth. If the general history of the design can be eliminated

What was the origin of the design?

LOGIC TREE DIAGRAM FOR DESIGN ORIGIN

Figure 23

as having any bearing on cause, the investigation can be shifted to other questionable areas. In a contrasting situation, if the equipment under study is the biggest, fastest, or most sophisticated ever built by the manufacturer, the root cause to the problem might well be a design deficiency. For this case, questions concerning design fundamentals, analysis, etc., should be pursued with the equipment designer as possible root causes of the problem.

While conducting the investigation, new areas are explored as information is acquired and assessed. New questions are developed and areas of the investigation are deleted or expanded as results warrant.

For any study, the results are only as good as the people performing it. No method is foolproof, and it is only luck to have the correct answer "fall out of the sky." One of the most difficult aspects of problem solving is assembling the correct team of people to review available inputs and develop new information. If knowledgeable people cannot be brought together; or if their answers to questions are incorrect or misleading, then the success of the investigation is jeopardized.

SUMMARY

Until such time that the root cause of a power plant problem is discovered and corrected, future equipment failures and plant outages may be encountered. By developing a cause of failure diagram to determine the apparent cause of a plant problem and logic trees to discover the root cause of the problem, the investigator is able to solve plant problems and provide corrective actions that prevent their future reoccurrence.

APPENDIX C

FINANCIAL AND BENEFIT/COST ANALYSIS

APPENDIX C

FINANCIAL AND BENEFIT/COST ANALYSIS

The preliminary procedure for ranking prospective improvement projects is by the gain inequivalent availability factor (ΔEAF) determined by the methods presented in this handbook. The feasibility of improvement projects, however, must be determined on the basis of capital cost, operating and maintenance expenses, improvements in plant heat rate, and purchase power cost associated with such projects. Based on these costs and the dollar worth of changes in plant availability, a benefit/cost ratio can be developed and used for further ranking prospective improvement projects.

COST ANALYSIS METHOD

There are several available methods for performing an economic assessment of a power plant improvement project. If a reliability engineer has available such financial data as debt to equity ratio, depreciation schedules, deferred taxes, and insurance payments, then a very detailed financial analysis can be performed for prospective improvement projects. However, this kind of information is often considered by a utility as sensitive and is not generally made known outside the comptroller's office. Sometimes in-house financial computer programs and system planning analysis are available to the reliability engineer interested in evaluating alternatives. If available, such programs should be used to develop the cost and benefits of specific improvement projects.

For this handbook, a fixed charge rate method of evaluating the cost of a utility's expense to make an improvement is developed. This method produces the present cost of an expenditure of money. Benefits are evaluated by a similar means -- a present worth of future benefits method. Both methods are simple and easily workable by a utility engineer interested in developing benefit/cost ratios for ranking prospective improvement projects developed from the AIM methodology.

The fixed charge approach for assessing improvement costs corrects a capital expenditure into a series of levelized annual payments known as future revenue requirements. The levelized annual payments (including such noncapital expenses as operating and maintenance costs) are then converted to a present value in order to determine the expected cost of an

improvement project in terms of a single sum of current dollars. This is compared with the present value of the benefits of the project (EAF improvement, heat rate reduction, etc.) to determine a benefit/cost ratio that indicates the relative merits of the project compared to other possible plant improvements.

Present Cost of a Capital Improvement Project

The fixed charge rate for capital equipment purchased for a particular power plant consists of the following items:

- Return on investment (cost of money);
- Depreciation;
- Federal Income Tax,
- Property Tax,
- Insurance,
- Miscellaneous.

The sum of these items yields the levelized fixed charge rate (FCR) for the purchase of plant equipment. The levelized annual cost (LAC) for a specific capital improvement project is found by:

$$LAC = CE \times FCR \quad (C.1)$$

where

CE is the capital expense in present day dollars of the improvement project.

The present value revenue requirement (PVRR) for making such a capital improvement is given by:

$$PVRR = LAC \times PWF_u \quad (C.2)$$

where

PWF_u is the present worth factor of a uniform series of payments and is found from:

$$PWF_u = \frac{(1 + j)^{n_1} - 1}{j (1 + j)^{n_1}} \quad (C.3)$$

where

j is the discount rate or cost of money to a utility

n_1 is the useful lifetime of the capital equipment being purchased in years.

Present Value of Operating and Maintenance Expenses

Calculation of the present value revenue requirement (PVRR) determines the cost of a non-recurrent (one-time-only) capital purchase of equipment. Improvement projects in a plant can involve more than the one-time cost to purchase and install equipment. Two other costs are normally associated with plant improvement projects:

- ° Nonrecurrent (one-time only operating and maintenance (O&M) expenses; and
- ° Yearly O&M costs.

The present value of a future one-time, nonrecurrent O&M expenditure (PVNR) is determined from:

$$PVNR = C_1 \left(\frac{1+i}{1+j} \right)^{n_2} \quad (C.4)$$

where

C_1 is the cost of the nonrecurrent expenditure in present day dollars

i is the escalation rate

j is the discount rate

n_2 is the number of years until the expense will be incurred

The other type of expense to be evaluated is a recurrent O&M cost, such as a yearly cost resulting from an improvement project. In this analysis, this cost is assumed to be of equal annual amounts prior to inflation. If C_2 is the present day cost of the recurrent expense and n_3 is the number of years of payment, then the present value of such a recurrent expense (PVRC) is found from:

$$PVRC = C_2 \frac{(1+j)}{(j-i)} \left[1 - \left(\frac{1+i}{1+j} \right)^{n_3} \right] \quad (C.5)$$

where

i and j are as above and

n_3 is the lifetime over which this expense will be incurred, usually equal to n_1

Using the above three factors -- present value revenue requirement, present value nonrecurrent expense, and the present value recurrent expense -- a reliability engineer is able to accurately assess the total present cost (PC) of a proposed improvement project as follows:

$$PC = PVRR + PVNR + PVRC \quad (C.6)$$

Example of the Present Value Cost of an Improvement Project

To illustrate this calculation, consider the following example. A proposed modification evaluated in section 6 of this handbook involves purchasing a fifth pulverizer to increase unit availability. The new pulverizer will require minor yearly servicing consisting of some materials (seals, etc.) and some labor. Additionally, a major overhaul of the pulverizer (replace bearings, etc.) will be required every five years. The plant economic data is found to be the following:

Return on investment	10.8%
Depreciation	2.4
Federal Income Tax.....	3.2
Property Tax	} 1.8
Insurance	
Miscellaneous	
Levelized Fixed Charge Rate (FCR)	18.2%

Discount Rate (j)	=	11.0%
Escalation Rate (i)	=	8.0%
Useful Pulverizer Lifetime	=	20 years

The three factors -- present value revenue requirement (PVRR), present value nonrecurrent expense (PVNR), and present value recurrent expense (PVRC) -- are calculated from equations (C.2), (C.4), and (C.5) and plant cost data as follows:

Present Value Revenue Requirement

	<u>1980 Dollars</u>
Cost of pulverizer	\$750,000
Labor to install pulverizer.....	60,000
Subtotal.....	<u>\$810,000</u>
Contingencies (5%).....	40,500
Interest during construction (8.5% for 2 months).....	<u>12,050</u>
Total Capital Expense (CE)....	\$862,550

$$\text{Levelized Annual Cost (LAC)} = \text{CE} \times \text{FCR} = \$862,550 \times .182 \\ = \$156,984$$

$$\text{Present Value Revenue Requirement (PVRR)} = \text{LAC} \times \text{PWF}_u$$

$$= \$156,984 \left(\frac{(1 + .11)^{20} - 1}{.11 (1 + .11)^{20}} \right) = \underline{\underline{\$1,250,113}}$$

Present Value Nonrecurrent O&M Expense

Cost to replace major parts every 5th year:

Materials.....	\$7,500
Labor.....	<u>2,200</u>
Subtotal.....	\$9,700

$$\begin{aligned}\text{Present Value 5th Year (PVNR/5th)} &= 9,700 \left(\frac{1 + .08}{1 + .110} \right)^5 \\ &= \$ 8,458\end{aligned}$$

$$\begin{aligned}\text{Present Value 10th Year (PVNR/10th)} &= 9,700 \left(\frac{1 + .08}{1 + .110} \right)^{10} \\ &= \$ 7,375\end{aligned}$$

$$\begin{aligned}\text{Present Value 15th Year (PVNR/15th)} &= 9,700 \left(\frac{1 + .08}{1 + .110} \right)^{15} \\ &= \$ 6,431\end{aligned}$$

$$\begin{aligned}\text{Total Present Value Nonrecurrent} \\ \text{O\&M (PVNR)} &= \underline{\underline{\$22,264}}\end{aligned}$$

Present Value Recurrent O&M Expense

Yearly repairs pulverizer
 Materials.....\$2,700
 Labor.....800
 Subtotal....\$3,500

Present Value Recurrent O&M (PVRC) =

$$3500 \left(\frac{1 + .110}{.110 - .08} \right) \left[1 - \left(\frac{1 + .08}{1 + .110} \right)^{20} \right] = \$54,633$$

Total Present Value of Pulverizer
 Addition Project.....PVRR \$1,250,113
 PVNR 22,264
 PVRC 54,633
 \$1,327,010

This cost (\$1,327,010) is the present value of the lifetime cost (PC) expressed in 1980 dollars needed to make this addition of a fifth pulverizer and service it over its 20-year lifetime. It must be offset by benefits (Δ EAF, improved plant heat rate, etc.) to make such an expense worthwhile.

BENEFIT ANALYSIS METHOD

The benefits of an improvement project are determined by calculating the effect of the project on future plant performance; namely, an improvement in equivalent availability factor (Δ EAF), a possible heat rate improvement, possible reductions in O&M expenses, and a possible increase in the unit's gross maximum capacity. The fourth measure, increased gross maximum capacity, is not treated in this analysis but should be included for improvement projects that are capable of increasing a plant's electrical output by even a small amount.

The change in plant equivalent availability is determined by the methods of this handbook. Heat rate improvements associated with component changes can be obtained from heat balance calculations and/or computer codes, operating curves supplied by equipment manufacturers or, in some cases, can be estimated by an experienced power plant engineer. Heat rate improvements translate directly into fuel savings and can have a sizeable worth in today's high cost fuel situation. O&M costs are determined for improvements by estimating the servicing requirements, materials, and labor needed to maintain the new equipment.

Once the improved equivalent availability factor, heat rate change, and O&M costs are accurately determined, each is converted into a present dollar value for comparison with the cost of performing the improvement project; i.e., purchase new equipment, change procedures, etc. For the discussion presented in this workbook, it is assumed that only the first seven (7) years of the improvement are examined when calculating the benefit of the project. This is due to uncertainties in the unit's future loading schedule. It is well understood in the utility industry that as units become older, they are usually loaded on a reduced schedule. With a future reduction in a unit's service hours, the dollar benefits of a Δ EAF improvement is reduced. This effect may be more than offset by increased power replacement costs, but the uncertainty of these future effects leads one to believe that the dollar

benefits of the improvements are not the same over the entire length of the project. For this reason, it is recommended that a conservative approach be taken and the benefits should be assessed over a shortened period of time compared to the costs.

Benefit of an Improvement Project in ΔEAF

A ΔEAF increase results in a yearly gain in total plant output, thereby reducing the need to purchase replacement power when the plant is off-line or in a derated condition. The GADS data methods used in determining ΔEAF in this methodology do not record the cost of power replacement for each outage or derate event. Power replacement costs are usually available from load dispatch records for various event time periods. One can easily determine an average replacement power cost (ARPC) for an event that takes place on several occasions by averaging this data using the following formula:

$$ARPC \text{ (\$/KWhr)} = \frac{\sum_{i=1}^n (\text{\$/KWhr})_i \times t_i}{\sum_{i=1}^n t_i} \quad (C.7)$$

where

t_i is the time period of an outage or derate event i

$(\text{\$/KWhr})_i$ is the replacement power cost determined at the time of event i from load dispatch records.

If, for some reason, the power replacement cost is not available for various event time periods, the average yearly replacement power cost for a plant can be used without introducing much error in the calculation.

Knowing the cost of replacement power ($\text{\$/KWhr}$), the yearly savings in replacement power cost (RP) of a ΔEAF improvement project is determined from:

$$RP = \Delta EAF \times GMC \times SH \times ARPC \times 10 = \text{\$/yr} \quad (C.8)$$

where

ΔEAF is the change in unit equivalent availability factor in %

GMC is the unit's gross maximum capacity in MW

SH is the unit's service hours per year in hours

ARPC is the average replacement power cost in \$/KWhr.

Additional Benefits of the Improvement Project

In addition to an increase in ΔEAF resulting from an improvement project, another benefit of a plant improvement project might be a reduction in the plant heat rate (i.e., an efficiency improvement resulting in a fuel savings).

The yearly benefit of a heat rate reduction (HR) can be determined from the following expression:

$$HR = \Delta HR \times GMC \times FC \times SH \times \frac{1}{1000} = \$/\text{yr} \quad (C.9)$$

where

ΔHR is the change in the heat rate in BTU/KWhr

FC is the fuel cost in \$ per million BTU's

GMC and SH are as above.

A third possible benefit of a plant improvement project might be a reduction in an O&M expense (ROM). An assessment of the yearly benefit of such a reduction in servicing the equipment compared to the present equipment can be made by plant engineers and equipment suppliers.

Total Benefits from an Improvement Project

The total yearly benefit (TYB) resulting from an improvement project equals the sum of the yearly replacement power cost (RP), the yearly heat rate savings (HR), and the yearly reduced O&M expense (ROM).

$$TYB = RP + HR + ROM \quad (C.10)$$

Assuming that TYB is the same each year, the present worth of the yearly benefits (PB) can be found from:

$$PB = TYB \left(\frac{1+j}{j-1} \right) \left[1 - \left(\frac{1+i}{1+j} \right)^{n_4} \right] \quad (C.11)$$

where

j is the discount rate

i is the escalation rate

n_4 is the number of years over which the improvement is evaluated (as explained previously, not more than 7 years due to future uncertainties in the plant operating schedule).

Example of the Present Value Benefits of an Improvement Project

Consider the same example as discussed previously; i.e., addition of a fifth pulverizer (Example 1). Assume the improvement results in the following changes:

Change in equivalent availability (ΔEAF)	=	2.97%
Change in heat rate (ΔHR)	=	0
Reduction in O&M expense (ROM)	=	0

The plant data from Example 1 is as follows:

Gross maximum capacity (GMC)	=	400 MW
Service hours per year (SH)	=	8328 hrs.
Average power replacement cost (APRC) found from load dispatch records and calculated by equation (C.7)	=	0.030 \$/KWhr

The yearly saving in replacement power cost is found from equation (C.8) as follows:

$$\begin{aligned}
 RP &= \Delta EAF \times GMC \times SH \times ARPC \times 10 \\
 &= 2.97 \times 400 \times 8327 \times .030 \times 10 = \$2,967,743
 \end{aligned}$$

The yearly benefit from a heat rate improvement is found from equation (C.9), and for this improvement project is found to be zero. The O&M cost reduction is also determined as zero. In fact, in this example as previously described, the new pulverizer results in additional servicing, a cost not a benefit.

The total yearly benefit (TYB) is:

Yearly saving in replacement power cost (RP)	=	\$2,967,743
Yearly saving from heat rate reduction (HR)	=	-0-
Yearly saving in O&M cost	=	-0-
TOTAL (TYB)		\$2,967,743

The present value of this yearly benefit over a seven-year period (i.e., the reason for selecting this period compared to the plant or equipment life is discussed previously) is calculated as follows from equation (C.11) assuming:

Evaluation period (n)	=	7 years
Discount rate (j)	=	11.0%
Escalation rate (i)	=	8%

Present value of benefits of improvement project is:

$$\begin{aligned}
 PB &= \$2,967,743 \left[\frac{.1 + .11}{.11 - .08} \right] \left[1 - \left(\frac{1 + .08}{1 + .11} \right)^7 \right] \\
 PB &= \$19,162,025
 \end{aligned}$$

Benefit/Cost Ratio

The benefit/cost ratio is formed for each improvement project by dividing the seven-year benefit of the project (reduced equivalent unavailability, heat rate improvement, and O&M reduction) by the lifetime cost to perform the improvement (capital and O&M). The larger the benefit/cost ratio, the more cost-effective the project. In the example given, the benefit/cost ratio is:

$$\text{Benefit/Cost} = \frac{\$19,162,025}{\$1,327,010} = 14.4$$

Projects should be ranked by their benefit/cost ratios and decisions concerning investments in plant improvement should be determined on the basis of this ratio.

As described in this analysis, benefit/cost ratios greater than one are cost effective; i.e., the seven-year benefit realized from improved plant performance more than offsets the cost of the improvement project. Obviously, the analysis developed in this presentation is elementary. Sensitivity analysis should be considered to determine ranges of benefit/cost ratios considering the various changes in operating schedules, fuel cost, etc., that might be encountered in future plant operation. The seven-year period for calculating the present value of the project benefits should be scrutinized in light of projected plant operating schedules, inflation rates, and cost of future money. ΔEAF itself is apt to be a variable changing as plant equipment becomes older and more prone to failure.

Although only approximate and subject to the inaccuracies discussed above, the benefit/cost approach for ranking improvement projects is considered to be the best available method for scheduling future plant improvements.

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