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IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems



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IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems

Sponsor

**Power Systems Reliability Subcommittee
of the
Power Systems Engineering Committee
of the
IEEE Industry Applications Society**

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Abstract: The fundamentals of reliability analysis as it applies to the planning and design of industrial and commercial electric power distribution systems are presented. Included are basic concepts of reliability analysis by probability methods, fundamentals of power system reliability evaluation, economic evaluation of reliability, cost of power outage data, equipment reliability data, examples of reliability analysis. Emergency and standby power, electrical preventive maintenance, and evaluating and improving reliability of the existing plant are also addressed. The presentation is self-contained and should enable trade-off studies during the design of industrial and commercial power systems.

Keywords: Designing reliable industrial and commercial power systems, equipment reliability data, industrial and commercial power systems reliability analysis, reliability analysis.

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Foreword

(This Foreword is not a part of IEEE Std 493-1990, IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems.)

The design of reliable industrial and commercial power systems is of considerable interest to many people. Prior to 1962, a qualitative viewpoint was taken when attempting to achieve this objective. The need for a quantitative approach was first recognized in the early 1960's when a small group of pioneers led by W. H. Dickinson organized an extensive AIEE survey of the reliability of electrical equipment in industrial plants. The AIEE survey that was taken in 1962 was followed by several IEEE reliability surveys, which were published in 1973 through 1979. These surveys from the the 1970's were the basis for the reliability data contained in IEEE Std 493-1980. Six additional IEEE reliability surveys have been conducted and published during the 1980's and have been used in this revision of IEEE Std 493-1980. IEEE Std 493-1990 also includes pertinent tutorial reliability material and the cost of power interruptions data.

Tutorial reliability sessions on the design of industrial and commercial power systems were conducted at technical conferences of the IEEE Industry Applications Society in 1971, 1976, and 1980.

This recommended practice was prepared by a working group of the Power Systems Reliability Subcommittee, Power Systems Engineering Committee, Industrial and Commercial Power Systems Department of the IEEE Industry Application Society.

At the time it recommended these practices, the working group of the Power Systems Reliability Subcommittee had the following members:

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Acknowledgment is given to the members of the working groups that compiled the 14 IEEE committee reports which are contained in the Appendixes. Acknowledgment is also given for the three equipment reliability surveys conducted by others which are summarized in Appendixes I, J, and L.

Chapter 1

Introduction

1.1 Objectives and Scope. The objective of this book is to present the fundamentals of reliability analysis as it applies to the planning and design of industrial and commercial electric power distribution systems. The text material is primarily directed toward consulting engineers and plant electrical engineers.

The design of reliable industrial and commercial power distribution systems is important because of the high costs associated with power outages. There is a need to be able to consider the cost of power outages when making design decisions for new power distribution systems and to be able to make quantitative cost versus reliability trade-off studies. The lack of credible data concerning equipment reliability and the cost of power outages has hindered engineers in making such studies.

The authors of this book have attempted to provide sufficient information so that reliability analyses can be performed on power systems without the need for cross references to other texts. Included are:

- (1) Basic concepts of reliability analysis by probability methods
- (2) Fundamentals of power system reliability evaluation
- (3) Economic evaluation of reliability
- (4) Cost of power outage data
- (5) Equipment reliability data
- (6) Examples of reliability analysis

In addition, discussion and information are provided on:

- (1) Emergency and standby power
- (2) Electrical preventive maintenance
- (3) Evaluating and improving reliability of the existing plant

A quantitative reliability analysis includes making a disciplined evaluation of alternate power distribution system design choices. When costs of power outages at the various building and plant locations are factored into the evaluation, the decisions can be based upon *total owning cost over the useful life of the equipment* rather than simply *first cost* of the system. The material in this book should enable engineers to make more use of quantitative cost versus reliability trade-off studies during the design of industrial and commercial power systems.

1.2 IEEE Surveys of Industrial Plants. From 1973 through 1989, the Power Systems Reliability Subcommittee of the Power Systems Engineering Committee of the IEEE Industry Applications Society conducted and published the results of

extensive surveys of the reliability of electrical equipment in industrial plants and also the cost of power outages for both industrial plants and commercial buildings. This included motors, motor starters, generators, power transformers, rectifier transformers, circuit breakers, disconnect switches, bus duct, switchgear bus-bare, switchgear bus-insulated, open wire, cable, cable joints, cable terminations, and electric utility power supplies. The results from these surveys have been published in 15 IEEE committee reports, 14 of which are included in this book in Appendixes A, B, C, D, E, G, H, and K. Appendix F gives the procedure used for conducting these surveys. It has been considered important that the "reasons for conducting the survey" be written down at the beginning of each new survey. It has also been considered important that the final report receive both oral and written discussion at the end of each survey. Some of the IEEE surveys have also included the cost of power interruptions, critical service loss duration time, and plant restart time. The most important results from these 15 surveys have been summarized in Chapters 2, 3, and 5. Table 10 in Chapter 3 contains a summary of the latest equipment reliability data from these surveys; and these values are suggested for use in the absence of better data which may be available from the reader's own experience. Table 9 presents a guide of where to look in this book for additional reliability data for each of several equipment categories.

Three important equipment reliability surveys conducted by others have been summarized and included as Appendixes I, J, and L; these appendixes supplement the IEEE equipment reliability surveys in some categories in which there has been little or no data and in other categories in which the data is more recent and/or much more extensive. These three equipment reliability surveys include:

- (1) Cable, cable splices, and cable terminations
- (2) High-voltage circuit breakers above 63 kV
- (3) Diesel and gas turbine generating units

An extensive bibliography on electrical service interruption costs is presented in Appendix M.

The reliability survey data contained in this book provide historical experience to those who have not been able to collect their own data. Such data can be an aid in analyzing, designing, or redesigning an industrial or commercial system and can provide a basis for the quantitative comparison of alternate designs.

1.3 How to Use This Book. This book is primarily directed toward consulting engineers and plant electrical engineers and covers the fundamentals of reliability analysis as it applies to the planning and design of industrial and commercial electric power distribution systems. The methods of reliability analysis are based upon probability and statistics. Some users of this book may wish to read Chapter 8 on basic probability concepts before reading Chapter 2 on planning and design. Other users may wish to start with Chapter 2 and not wish to attempt to fully understand the derivation of the statistical formulas given in 2.1.9, and 2.1.11.1.

The most important parts of planning and design are covered in 2.1 and 2.2 on fundamentals of power system reliability evaluation and on the economic evaluation of reliability. Chapter 7 gives six examples using these methods of analysis. These examples cover some of the most common decisions that engineers are faced

with when designing a power distribution system. Some discussion on the limitations of reliability and availability predictions are given in the latter part of 7.1.

Those wishing to obtain equipment reliability data should go to Chapter 3. Those wishing to obtain data on the cost of electrical interruptions to industrial plants or commercial buildings should consult 2.2. Any data on costs may need to be updated to take into account the effects of inflation.

The importance of electrical preventive maintenance in planning and design is covered in 2.3 and 2.4. Chapter 5 discusses the subject in further detail and contains data showing the effect of maintenance quality on equipment failure rates.

Many reliability studies need to be followed up by considerations for emergency and standby power. This subject is covered in Chapter 6 and may also be considered part of planning and design.

An approach to evaluating and upgrading the reliability of an existing plant is presented in Chapter 4. Some users of this book may wish to start with this chapter.

1.4 Definitions. The following definitions should be used in conjunction with this recommended practice:

availability. The steady-state probability that a component is in service.

component. A piece of electrical or mechanical equipment, a line or circuit, or a section of a line or circuit, or a group of items that is viewed as an entity for the purposes of reliability evaluation.

electrical equipment. A general term including materials, fittings, devices, appliances, fixtures, apparatus, machines, etc., used as a part of, or in connection with, an electric installation.

electrical preventive maintenance. A system of planned inspection, testing, cleaning, drying, monitoring, adjusting, corrective modification, and minor repair of electrical equipment to minimize or forestall future equipment operating problems or failures; which, depending upon equipment type, may require exercising or proof testing.

expected failure duration. The expected or long-term average duration of a single failure event.

expected interruption duration. The expected, or average, duration of a single load interruption event.

exposure time. The time during which a component is performing its intended function and is subject to failure.

failure. Any trouble with a power system component that causes any of the following events to occur:

- (1) Partial or complete plant shutdown, or below-standard plant operation
- (2) Unacceptable performance of user's equipment
- (3) Operation of the electrical protective relaying or emergency operation of the plant electrical system

(4) De-energization of any electric circuit or equipment

A failure on a public utility supply system may cause the user to have either of the following:

- (1) A power interruption or loss of service
- (2) A deviation from normal voltage or frequency outside the normal utility profile

A failure on an in-plant component causes a forced outage of the component, that is, the component is unable to perform its intended function until it is repaired or replaced. The terms “failure” and “forced outage” are often used synonymously.

failure rate (forced outage rate). The mean number of failures of a component per unit exposure time. Usually exposure time is expressed in years and failure rate is expressed in failures per year.

forced outage. An outage (failure) that cannot be deferred.

forced unavailability. The long-term average fraction of time that a component or system is out of service due to a forced outage (failure).

interruption. The loss of electric power supply to one or more loads.

interruption frequency. The expected (average) number of power interruptions to a load per unit time, usually expressed as interruptions per year.

mean time between failures (MTBF). The mean exposure time between consecutive failures of a component. It can be estimated by dividing the exposure time by the number of failures in that period, provided that a sufficient number of failures has occurred in that period.

mean time to repair (MTTR). The mean time to repair a failed component. It can be estimated by dividing the summation of repair times by the number of repairs, and, therefore, it is practically the average repair time.

minimal cut-set. A set of components that, if removed from the system, results in loss of continuity to the load point being investigated and that does not contain as a subset any set of components that is itself a cut-set of the system.

offline system. A system that is dormant until it is called upon to operate, such as a diesel generator that is started up when a power failure occurs.

online system. A system that is operating at all times, such as an inverter supplied by dc power via the primary power source through a battery charger.

outage. The state of a component or system when it is not available to properly perform its intended function.

repair time. The repair time of a failed component or the duration of a failure is the clock time from the occurrence of the failure to the time when the component is restored to service, either by repair of the failed component or by substitution of a spare component for the failed component. It includes time for diagnosing the

trouble, locating the failed component, waiting for parts, repairing or replacing, testing, and restoring the component to service. The terms “repair time” and “forced outage duration” are often used synonymously. It is not the time required to restore service to a load by putting alternate circuits into operation.

scheduled outage. An outage that results when a component is deliberately taken out of service at a selected time, usually for purposes of construction, maintenance, or repair.

scheduled outage duration. The period from the initiation of a scheduled outage until construction, preventive maintenance, or repair work is completed and the affected component is made available to perform its intended function.

scheduled outage rate. The mean number of scheduled outages of a component per unit exposure time.

switching time. The period from the time a switching operation is required due to a component failure until that switching operation is completed. Switching operations include such operations as: throwover to an alternate circuit, opening or closing a sectionalizing switch or circuit breaker, reclosing a circuit breaker following a tripout due to a temporary fault, etc.

system. A group of components connected or associated in a fixed configuration to perform a specified function of distributing power.

unavailability. The long-term average fraction of time that a component or system is out of service due to failures or scheduled outages. An alternative definition is the steady-state probability that a component or system is out of service due to failures or scheduled outages.

Chapter 2 Planning and Design

2.1 Fundamentals of Power System Reliability Evaluation

2.1.1 Reliability Evaluation Fundamentals. Fundamentals necessary for a quantitative reliability evaluation of electric power systems include definitions of basic terms, discussions of useful measures of system reliability and the basic data needed to compute these indexes, and a description of the procedure for system reliability analysis including computation of quantitative reliability indexes.

2.1.2 Power System Design Considerations. An important aspect of power system design involves consideration of the service reliability requirements of loads that are to be supplied and the service reliability that will be provided by any proposed system. System reliability assessment and evaluation methods based on probability theory that allow the reliability of a proposed system to be assessed quantitatively are finding wide application today. Such methods permit consistent, defensible, and unbiased assessments of system reliability that are not otherwise possible.

The quantitative reliability evaluation methods presented here permit reliability indexes for any electric power system to be computed from knowledge of the reliability performance of the constituent components of the system. Thus, alternative system designs can be studied to evaluate the impact on service reliability and cost of changes in component reliability, system configuration, protection and switching scheme, or system operating policy including maintenance practice.

2.1.3 Definitions. The definitions presented here include those used in the survey of the reliability of electrical equipment in industrial plants (see Reference [16]).¹ The definitions presented here are not exhaustive, but do provide much of the required nomenclature for discussions of power system reliability.

availability. This term may apply either to the performance of individual components or to that of a system. Availability is defined to be the long-term average fraction of time that a component or system is in service satisfactorily performing its intended function. An alternative and equivalent definition for availability is the steady-state probability that a component or system is in service.

component. A piece of electrical or mechanical equipment, a line or circuit, or a section of a line or circuit, or a group of items that is viewed as an entity for the purposes of reliability evaluation.

¹The numbers in brackets correspond to those in the references at the end of this chapter.

expected interruption duration. The expected, or average, duration of a single load interruption event.

exposure time. The time during which a component is performing its intended function and is subject to failure.

failure. Any trouble with a power system component that causes any of the following events to occur:

- (1) Partial or complete plant shutdown, or below-standard plant operation
- (2) Unacceptable performance of user's equipment
- (3) Operation of the electrical protective relaying or emergency operation of the plant electrical system
- (4) De-energization of any electric circuit or equipment

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interruption. The loss of electric power supply to one or more loads.

interruption frequency. The expected (average) number of power interruptions to a load per unit time, usually expressed as interruptions per year.

outage. The state of a component or system when it is not available to properly perform its intended function.

repair time. The repair time of a failed component or the duration of a failure is the clock time from the occurrence of the failure to the time when the component is restored to service, either by repair of the failed component or by substitution of a spare component for the failed component. It includes time for diagnosing the trouble, locating the failed component, waiting for parts, repairing or replacing, testing, and restoring the component to service. The terms "repair time" and "forced outage duration" are often used synonymously. It is not the time required to restore service to a load by putting alternate circuits into operation.

scheduled outage. An outage that results when a component is deliberately taken out of service at a selected time, usually for purposes of construction, maintenance, or repair.

scheduled outage duration. The period from the initiation of a scheduled outage until construction, preventive maintenance, or repair work is completed and the affected component is made available to perform its intended function.

scheduled outage rate. The mean number of scheduled outages of a component per unit exposure time.

switching time. The period from the time a switching operation is required due to a component failure until that switching operation is completed. Switching operations include such operations as: throwover to an alternate circuit, opening or closing a sectionalizing switch or circuit breaker, reclosing a circuit breaker following a tripout due to a temporary fault, etc.

system. A group of components connected or associated in a fixed configuration to perform a specified function of distributing power.

unavailability. The long-term average fraction of time that a component or system is out of service due to failures or scheduled outages. An alternative definition is the steady-state probability that a component or system is out of service. Mathematically, $\text{unavailability} = (1 - \text{availability})$.

2.1.4 System Reliability Indexes. The basic system reliability indexes (see References [2], [9], [10], and [20]) that have proven most useful and meaningful in power distribution system design are:

- (1) Load interruption frequency
- (2) Expected duration of load interruption events

These indexes can be readily computed using methods that will be described later. The two basic indexes of interruption frequency and expected interruption duration can be used to compute other indexes that are also useful:

- (1) Total expected (average) interruption time per year (or other time period)
- (2) System availability or unavailability as measured at the load supply point in question
- (3) Expected, demanded, but unsupplied, energy per year

It should be noted here that the disruptive effect of power interruptions is often nonlinearly related to the duration of the interruption. Thus, it is often desirable to compute not only an overall interruption frequency but also frequencies of interruptions categorized by the appropriate durations.

2.1.5 Data Needed for System Reliability Evaluations. The data needed for quantitative evaluations of system reliability depend to some extent on the nature of the system being studied and the detail of the study. In general, however, data on the performance of individual components together with the times required to perform various switching operations are required.

System component data that are generally required are summarized as follows:

- (1) Failure rates (forced outage rates) associated with different modes of component failure
- (2) Expected (average) time to repair or replace failed component
- (3) Scheduled (maintenance) outage rate of component
- (4) Expected (average) duration of a scheduled outage event

If possible, component data should be based on the historical performance of components in the same environment as those in the proposed system being studied. The reliability surveys conducted by the Power Systems Reliability Subcommittee (see References [16] and [17]) provide a source of component data when such specific data are not available. These data and the data from later surveys have been summarized in Chapter 3.

The needed switching time data include:

- (1) Expected times to open and close a circuit breaker
- (2) Expected times to open and close a disconnect or throwover switch
- (3) Expected time to replace a fuse link
- (4) Expected times to perform such emergency operations as cutting in clear, installing jumpers, etc.

Switching times should be estimated for the system being studied based on experience, engineering judgment, and anticipated operating practices.

2.1.6 Method for System Reliability Evaluation. The method for system reliability evaluation that is recommended and presented here has evolved over a number of years (see References [2], [3], [9], [10], and [12]). The method, called the “minimal cut-set method,” is believed to be particularly well suited to the study and analysis of electric power distribution systems as found in industrial plants and commercial buildings. The method is systematic and straightforward and lends itself to either manual or computer computation. An important feature of the method is that system weak points can be readily identified, both numerically and nonnumerically, thereby focusing design attention on those sections of the system that contribute most to service unreliability. See Chapter 8 for a derivation of the minimal cut-set method.

The procedure for system reliability evaluation is outlined as follows:

- (1) Assess the service reliability requirements of the loads and processes that are to be supplied and determine the appropriate service interruption definition or definitions.
- (2) Perform a failure modes and effects analysis identifying and listing those component failures and combinations of component failures that result in service interruptions and that constitute minimal cut-sets of the system.
- (3) Compute the interruption frequency contribution, the expected interruption duration, and the probability of each of the minimal cut-sets of step (2).
- (4) Combine the results of step (3) to produce system reliability indexes.

These steps will be discussed in more detail in the sections that follow.

2.1.7 Service Interruption Definition. The first step in any electric power system reliability study should be a careful assessment of the power supply quality (e.g., sags, surges, harmonics, etc.) and continuity required by the loads that are to be served. This assessment should be summarized and expressed in a service interruption definition that can be used in the succeeding steps of the reliability evaluation procedure. The interruption definition specifies, in general, the reduced voltage level (voltage dip) together with the minimum duration of such a reduced voltage period that results in substantial degradation or complete loss of function of the load or process being served. Frequently, reliability studies are conducted on

a continuity basis, in which case, interruption definitions reduce to a minimum duration specification with voltage assumed to be zero during the interruption.

A further discussion of interruption definitions together with examples of such definitions is given in 7.1.2.

2.1.8 Failure Modes and Effects Analysis (FMEA). The FMEA for power distribution systems amounts to the determination and listing of those component outage events or combinations of component outages that result in an interruption of service at the load point being studied according to the interruption definition that has been adopted. This analysis must be made in consideration of the different types and modes of outages that components may exhibit and the reaction of the system's protection scheme to these events.

The primary result of the FMEA as far as quantitative reliability evaluation is concerned is the list of minimal cut-sets it produces. The use of the minimal cut-sets in the calculation of system reliability indexes is described in Chapter 8 of this book. A minimal cut-set is defined to be "a set of components that, if removed from the system, results in loss of continuity to the load point being investigated and that does not contain as a subset any set of components that is itself a cut-set of the system." In the present context, the components in a cut-set are just those components whose overlapping outage results in an interruption according to the interruption definition adopted.

An important nonquantitative benefit of the FMEA is the thorough and systematic thought process and investigation that it requires. Often weak points in system design will be identified before any quantitative reliability indexes are computed. Thus, the FMEA is a useful reliability design tool even in the absence of the data needed for quantitative evaluation.

The FMEA and the determination of minimal cut-sets is most efficiently conducted by considering first the effects of outages of single components and then the effects of overlapping outages of increasing numbers of components. Those cut-sets containing a single component are termed "first-order cut-sets." Similarly, cut-sets containing two components are termed "second-order cut-sets," etc. In theory, the FMEA should continue until all the minimal cut-sets of the system have been found. In practice, however, the FMEA can be terminated earlier since high-order cut-sets have low probability compared to lower order cut-sets. A good rule of thumb is to determine minimal cut-sets up to order $n + 1$, where n is the lowest-order minimal cut-set of the system. Since most power distribution systems have at least some first-order minimal cut-sets, the analysis can usually be terminated after the second-order minimal cut-sets have been found.

2.1.9 Computation of System Reliability Indexes. The list of minimal cut-sets obtained from FMEA is used to compute system reliability indexes. Since the occurrence of any cut-set will result in system failure, these cut-sets can be regarded as acting in series. The failure frequency and average outage duration can therefore be computed using Eqs 1 and 2.

$$f_s = \text{System interruption frequency} = \sum_i f_{cs_i} \quad (\text{Eq 1})$$

$$r_s = \text{System expected interruption duration} = \sum_i f_{cs_i} r_{cs_i} / f_s \quad (\text{Eq 2})$$

NOTE: These are approximate formulas and should only be used when $f_{cs_i} \times r_{cs_i}$ are less than 0.01.

where

f_{cs_i} = Frequency of cut-set event i.

r_{cs_i} = Expected duration of cut-set event i.

It can be seen from Eqs 1 and 2 that, once the frequency and duration of the various cut-sets are known, the load point interruption frequency and duration can be easily computed. Since the various cut-set events are not mutually exclusive, Eq 1 is an upper bound on the frequency of system failure. Assuming, however, that the time a component spends on outage is very small compared to the time it is operating satisfactorily, Eqs 1 and 2 give results close to the exact values. A later section gives equations for computing the frequency and duration for various types of outage events.

2.1.10 Component Failure Modes. Distribution system components, such as lines, transformers, and circuit breakers, are subject to a variety of failure modes that, in general, have different impacts on system reliability performance. For system reliability evaluation purposes, it is useful to categorize system components as switching devices or nonswitching devices. First, consider nonswitching devices, such as lines or transformers. The important modes of failure are those events that cause the component to be unable to fulfill its current-carrying function, generally due to a fault and subsequent isolation of the faulted component by a protective device. Such failure modes can be modeled in system reliability calculations through the use of permanent forced outage rates and transient forced outage rates, where

λ = Permanent forced outage rate of the component = Rate of occurrence of forced outages in which the component is damaged and cannot be restored to service until repair or replacement has been completed.

λ' = Transient forced outage rate of component = Rate of occurrence of forced outages in which the component is undamaged and can be immediately restored to service.

NOTE: A forced outage is defined as "an outage (failure) that cannot be deferred."

Now consider the failure modes of protection systems and of switching devices, such as circuit breakers. In contrast to the components described above whose only function is carrying current (a continuously required function), protection systems and switching devices generally have both continuously required as well as response functions. The inability to perform a continuously required function, such as current carrying, will immediately impact system performance while the inability to perform a response function, such as tripping open on command, will be manifested only when the response is required. Some of the more important failure

modes of protection systems and switching devices and the parameters used to model these failure modes in reliability calculations are summarized as follows:

Continuous Functions

- (1) Component short circuit resulting in operation of backup protective devices. The modeling parameter is λ , which is the rate of occurrence of such short-circuit events.
- (2) Switching device opening without the proper command. The modeling parameter is λ_{FT} , which is the rate of occurrence of such events given that the device is closed.
- (3) Switching device closing without the proper command. The modeling parameter is λ_{FC} , which is the rate of occurrence of such events given that the device is open.

Response Functions

- (1) Switching device failure to open on command. The modeling parameter is p_s , which is the probability that the device will not open on command.
- (2) Switching device failure to close on command. The modeling parameter is p_c , which is the probability that the device will not close on command.
- (3) Protection system trips incorrectly due to a fault outside of the protection zone. The modeling parameter is p_o , which is the probability of an incorrect trip, given a fault outside the protection zone.

2.1.11 Expressions for Outage Events. Expressions for computing the frequency, f_{cs} , and the expected durations, r_{cs} , of a cut-set event are summarized in this section. These expressions are generally approximate, but are sufficiently accurate for practical calculations in typical situations. The given expressions presume that all physically parallel paths in a distribution system are fully redundant, that is, it is presumed that any one path of parallel set is fully capable of carrying the highest load that may be experienced. Further, the failure bunching effects of storms and other common-mode or common-cause failures are not considered in the given expressions. These issues are fully described elsewhere (see References [2] and [10]) and are usually not numerically important in industrial and commercial distribution systems whose reliability performance is dominated by series components that yield first-order cut-sets.

2.1.11.1 Forced Outages of Current-Carrying Components. Now we will consider events of cessation of the continuous current-carrying function of any component. The following notations are used:

- f_{cs} = Frequency of cut-set event.
- r_{cs} = Expected duration of cut-set event = Expected duration of system failure event due to occurrence of the cut-set event.
- λ_i = Permanent forced outage rate of component i .
- λ'_i = Transient forced outage of component i .
- r_i = Expected repair or replacement time of component i .
- t = Time to perform an appropriate switching operation.

First, consider cut-sets associated with permanent forced outages.

First-Order (Single-Component) Cut-Sets

$$f_{cs} = \lambda_i \quad (\text{Eq 3})$$

$$r_{cs} = \min(r_i, t) = \text{Minimum of } r_i \text{ or } t \quad (\text{Eq 4})$$

Second-Order (Dual-Component) Cut-Sets

$$f_{cs} = \lambda_i \lambda_j (r_i + r_j) \quad (\text{Eq 5})$$

$$r_{cs} = \min(r_i r_j / (r_i + r_j), t) \quad (\text{Eq 6})$$

NOTE: Equations 5 and 6 are approximate formulas and should only be used when both $\lambda_i \times r_i$ and $\lambda_j \times r_j$ are less than 0.01.

Note that the above expressions for f_{cs} are approximate and assume that λ is much less than $1/r$. This is usually a reasonable assumption, but exact expressions are given in Chapter 8 and should be used if needed. Also note that, particularly in the above expressions for r_{cs} , system interruption durations may be determined by component repair or replacement times or by the time to restore service to interrupted loads through a switching operation. Thus, r_{cs} is very much a function of system topology and switching arrangements. It should also be noted that f_{cs} for second-order cut-sets may, in certain circumstances, also be a function of switching times rather than repair and replacement times. In such cases, the times r_i and r_j should be viewed as the appropriate switching times.

Next, consider cut-sets associated with transient forced outages or transient forced outage events overlapping permanent forced outage events. The likelihood of overlapping transient forced outages is considered remote and is not considered in this book.

First-Order (Single-Component) Cut-Sets

$$f_{cs} = \lambda'_i \quad (\text{Eq 7})$$

$$r_{cs} = t \quad (\text{Eq 8})$$

Second-Order (Dual-Component) Cut-Sets

$$f_{cs} = \lambda_j \lambda'_i r_j \quad (\text{Eq 9})$$

$$r_{cs} = t \quad (\text{Eq 10})$$

NOTE: Equation 9 is approximate and should only be used when $\lambda_j \times r_j$ is less than 0.01.

2.1.11.2 Failures of Switching Devices or Protection Systems. Now consider failure events of switching devices or protection systems. The frequency and duration of cut-set events associated with the short-circuit failure mode of switching devices can be calculated using Eqs 3 through 10 as appropriate. Similarly, if a switching device is normally operated closed, the effects of false trip events having a rate of λ_{FT} can be calculated using the approaches of Eqs 3 through 10. The event of switching device closure without proper command is not viewed as generally important from a distribution system reliability point of view (though it certainly is important from a safety viewpoint) and will not be treated in this book.

Switching device or protection system failures that render the device or system unable to respond properly to some other event may occur at the instant of required action or more probably represent undetected prior failures. Such latent failures are only revealed by the event calling for the device or system action. It follows, therefore, that response function failures of switching devices or protection systems never constitute first-order cut-sets since such failures do not in and of themselves result in load interruptions. Expressions for f_{cs} and r_{cs} for each of the response function failure modes follow. In these expressions, λ is the rate of occurrence of the event requiring a response.

Failure to open on command

$$f_{cs} = \lambda p_s \quad (\text{Eq 11})$$

$$r_{cs} = r \text{ or } t \text{ as appropriate} \quad (\text{Eq 12})$$

Failure to close on command

$$f_{cs} = \lambda p_c \quad (\text{Eq 13})$$

$$r_{cs} = r \text{ or } t \text{ as appropriate} \quad (\text{Eq 14})$$

Incorrect trip due to fault outside protection zone

$$f_{cs} = \lambda p_o \quad (\text{Eq 15})$$

$$r_{cs} = r \text{ or } t \text{ as appropriate} \quad (\text{Eq 16})$$

The probabilities p_s and p_c are very much influenced by inspection, maintenance, and testing policies. This follows since p_s and p_c largely reflect undetected prior failures at the time of a required response.

2.1.11.3 Scheduled Outages of Components. We will now consider system interruptions and their related cut-sets, which are associated with scheduled outages of components. A scheduled outage is defined as "an outage that results when a component is deliberately taken out of service at a selected time, usually for purposes of construction, maintenance, or repair." The distinction between a forced outage and a scheduled outage is the degree to which the outage can be postponed; a forced outage cannot be postponed, while a scheduled outage can be postponed, if necessary, to avoid consumer interruptions. Clearly, a scheduled outage of a component that constitutes a first-order cut-set will result in a consumer interruption regardless of the degree to which it can be postponed. However, the timing of such an outage is entirely controllable and can, therefore, be taken at times of minimum inconvenience and with forewarning. Therefore, such interruptions may not have the same impact as interruptions that occur at a random time and without warning. The frequency and duration of first-order cut-sets associated with scheduled outages are:

$$f_{cs} = \lambda_i'' \quad (\text{Eq 17})$$

$$r_{cs} = r_i'' \quad (\text{Eq 18})$$

where λ_i'' and r_i'' are the scheduled outage rate and average scheduled outage duration of the i th component.

In systems possessing redundant supply paths, consumer interruption should never occur due to overlapping scheduled outages of components. However, a component forced outage may overlap a preexisting component scheduled outage, thereby producing a consumer interruption and a second-order cut-set. The frequency and duration of a cut-set in which a forced outage of component j overlaps a scheduled outage of component i are given as follows:

$$f_{cs} = \lambda_i \lambda_j r_i^n \quad (\text{Eq 19})$$

$$r_{cs} = \frac{r_i^n r_j}{r_i^n + r_j} \quad \text{or } t \text{ as appropriate} \quad (\text{Eq 20})$$

Again, the assumption is that λ is much greater than $1/r$.

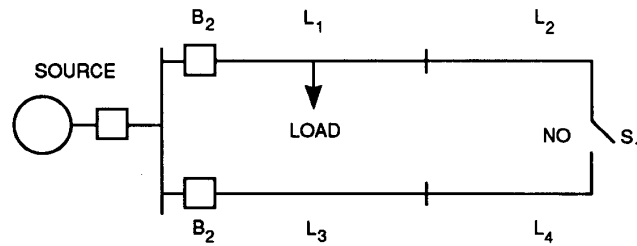
Table 1
Data for Example Systems

Line Sections
$\lambda = 0.20/\text{yr}$
$r = 3 \text{ h}$
Breakers and Switches
$\lambda = 0.01/\text{yr}$
$\lambda_{FT} = 0.003/\text{yr}$
$p_s = 0.001$
$p_o = 0.01$
$r = 5 \text{ h}$
Switching Times
$t_s = \text{Normal manual switching time} = 0.5 \text{ h}$
$t_B = \text{Time to isolate breaker or switch or to repair noncatastrophic failure} = 1 \text{ h}$

2.1.12 Example. A simple example will now be used to illustrate the application of the reliability evaluation concepts that have been presented to the evaluation of alternative system protection and sectionalizing schemes. The alternatives to be studied are shown in Figs 1, 2, and 3. More detailed examples using typical data are given in Chapter 7. In these examples, only the labeled line sections and circuit breakers or switches are considered fallible. Furthermore, in the interest of simplifying the example, scheduled outages and transient forced outages of components are not considered. Assumed numerical data for the example systems are shown in Table 1. In every case, the reliability performance indexes desired are the interruption rate and expected duration that would be experienced by a load served from line section L_1 .

Here an interruption is defined to be “the loss of continuity from the source to the load point for a time longer than that required for an automatic or remotely controlled switching operation.”

The analysis of each system is shown in the tables within Figs 1, 2, and 3. In the analysis, it is assumed that breakers are operated automatically or remotely, while



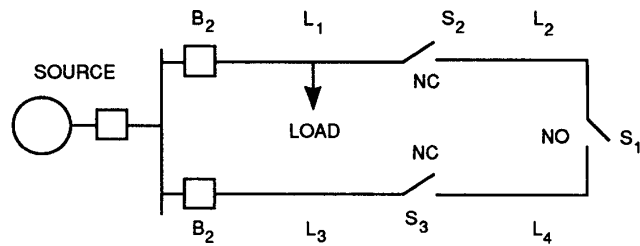
Cut-Set	(1) Frequency (failures/yr)	(2) Duration (h/failure)	(1) × (2)
Line Failures			
L_1	$\lambda = 0.20$	$r = 3$	0.20×3
L_2	$\lambda = 0.20$	$r = 3$	0.20×3
Breaker/Switch Failures			
Type 1: B_1	$\lambda = 0.01$	$t_B = 1$	0.01×1
Type 1: B_2	$\lambda = 0.01$	$t_B = 1$	0.01×1
Type 1: S_1	$\lambda = 0.01$	$t_B = 1$	0.01×1
Type 2: B_1	$\lambda_{FT} = 0.003$		0.003×1
	$\Sigma = 0.433$	$t_B = 1$	$\Sigma = 1.233$

where

$$f_s = 0.433 \text{ interruptions/yr}$$

$$r_s = 1.233 / 0.433 = 2.85 \text{ h/interruption}$$

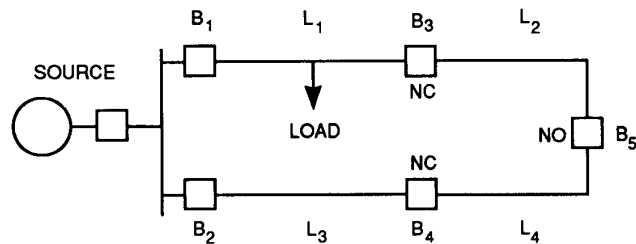
Fig 1
Example System — No Line Sectionalizing



Cut-Set	(1) Frequency (failures/yr)	(2) Duration (h/failure)	(1) × (2)
Line Failures			
L ₁	λ = 0.20	r = 3	0.20 × 3
L ₂	λ = 0.20	t _s = 0.5	0.20 × 0.5
Breaker/Switch Failures			
Type 1: B ₁	λ = 0.01	t _B = 1	0.01 × 1
Type 1: B ₂	λ = 0.01	t _B = 1	0.01 × 1
Type 1: S ₁	λ = 0.01	t _B = 1	0.01 × 1
Type 1: S ₂	λ = 0.01	t _B = 1	0.01 × 1
Type 2: B ₁	λ _{FT} = 0.003	t _B = 1	0.003 × 1
Type 4: B ₂	p _s (λ _{L₃} + λ _{L₄} + λ _{S₃})	t _B = 1	0.00041 × 1
	= 0.00041		
	Σ = 0.44341		Σ = 0.74341

where
f_s = 0.44341 interruptions/yr
r_s = 0.74341 / 0.44341 = 1.68 h/interruption

Fig 2
Example System — Lines Sectionalized with Switches



Cut-Set	(1) Frequency (failures/yr)	(2) Duration (h/failure)	(1) × (2)
Line Failures			
L_1	$\lambda = 0.20$	$r = 3$	0.20×3
Breaker/Switch Failures			
Type 1: B_1	$\lambda = 0.01$	$t_B = 1$	0.01×1
Type 1: B_2	$\lambda = 0.01$	$t_B = 1$	0.01×1
Type 1: B_3	$\lambda = 0.01$	$t_B = 1$	0.01×1
Type 4: B_3	$p_s(\lambda_{L_2} + \lambda_{B_5}) = 0.00021$	$t_B = 1$	0.00021×1
Type 4: B_2	$p_s(\lambda_{L_3} + \lambda_{B_4}) = 0.00021$	$t_B = 1$	0.00021×1
Type 6: B_1	$p_o(\lambda_{L_2} + \lambda_{B_5}) = 0.0021$	$t_B = 1$	0.0021×1
	$\Sigma = 0.23252$		$\Sigma = 0.63252$

where

$$f_s = 0.23 \text{ interruptions/yr}$$

$$r_s = 0.63252 / 0.23252 = 2.72 \text{ h/interruption}$$

Fig 3
Example System — Lines Sectionalized with Circuit Breakers

switches are operated manually. The results of the analyses are in agreement with intuition:

- (1) Sectionalizing circuits with noninterrupting devices reduces average interruption duration but has a minimal effect on the interruption rate.
- (2) Sectionalizing circuits with fault-interrupting devices cuts the interruption rate.

Note, however, that the average interruption duration of Case 3 is close to that of Case 1 and higher than that of Case 2. This points out that f_s and r_s may not move in the same direction as changes are made in the protection scheme and that the indexes f_s and r_s should be viewed as a complementary pair in reliability analysis.

2.1.13 Incomplete Redundancy. A common method of improving the reliability performance of a system is through component redundancy, for example, more than one transformer in a substation. Typically, each component of the redundant set has sufficient capacity, perhaps based on an emergency rating, to carry the peak load that the system may be asked to deliver. Such full redundancy is effective in improving system reliability performance but is usually quite expensive. If the load of the system is variable, the opportunity exists to cut costs by reducing the capacity of redundant components to levels less than that required to carry system peak load. Such component capacity reductions admit the possibility that one component of the redundant set might be called upon to carry system peak load and would thereby suffer an overload outage. An overload outage might result in an actual interruption of load or perhaps only some loss of life in the overloaded component, depending on the protection scheme in service.

A method exists (see References [1] and [7]) for computing the frequency, average duration, and probability of overload outage events as a function of component capacities and load characteristics. This method, which is compatible with the general reliability evaluation procedure outlined earlier, can be used to evaluate the cost/reliability trade-offs of incomplete redundancy. The method is briefly presented hereafter.

Consider a system possessing incomplete redundancy, and consider the forced outage of some set i of the components of this system. Let the frequency and probability of this forced outage event be f_i and P_i . Then the frequency, probability, and average duration of overloading events that are precipitated by loss of the components in set i are given approximately by:

$$\begin{aligned} f_{OL_i} &= f_i \times P(\text{load} \geq \text{capacity of remaining components}) \\ &\quad + P_i \times f(\text{load} \geq \text{capacity of remaining components}) \\ P_{OL_i} &= P_i \times P(\text{load} \geq \text{capacity of remaining components}) \\ D_{OL_i} &= P_{OL_i} / f_{OL_i} \end{aligned}$$

In the above expressions, $P(\text{load} \geq X)$ is called the “load-duration characteristic” and is simply the probability or proportion of time that the load is greater than or equal to X . A typical load-duration characteristic for utility load is shown in Fig 4. Similarly, $f(\text{load} \geq X)$ is called the “load-frequency characteristic” and is the rate with which events ($\text{load} \geq X$) occur. A typical load-frequency characteristic is shown in Fig 5. The reader is referred to Reference [1] for additional discussion of the load-duration and load-frequency characteristics.

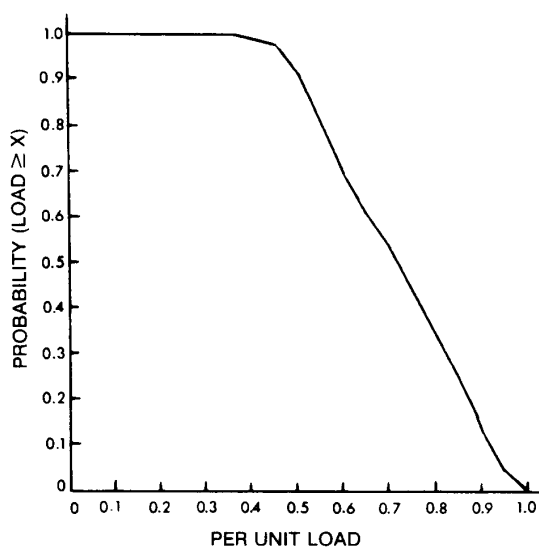


Fig 4
Typical Load-Duration Characteristic

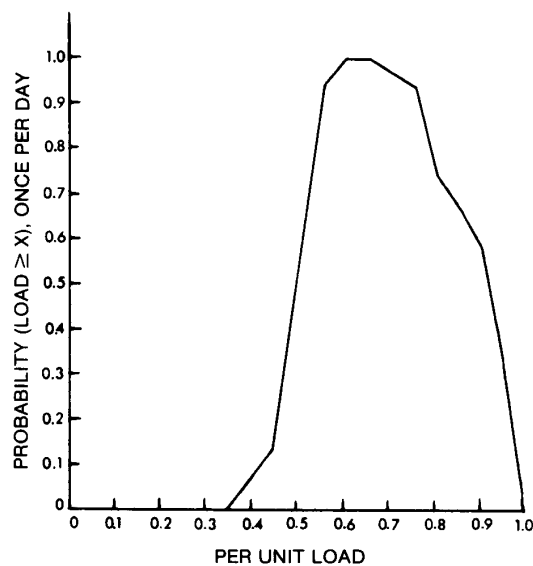


Fig 5
Typical Load-Frequency Characteristic

2.2 Costs of Interruptions—Economic Evaluation of Reliability

2.2.1 Cost of Interruptions versus Capital Cost. The type and extent of new or rehabilitated electric systems for industrial plants or commercial buildings must carefully balance the costs of anticipated interruptions to electrical service against the capital costs of the systems involved. Each instance requires a separate analysis taking into account special production and occupancy needs. Because of the many variables involved, one of the most difficult items to obtain is the cost of the electrical interruptions.

2.2.1.1 What Is an Interruption? Economic evaluation of reliability begins with the establishment of an interruption definition. Such a definition specifies the magnitude of the voltage dip and the minimum duration of such a reduced-voltage period that results in a loss of production or other function for the plant, process, or building in question. Frequently, interruption definitions are given only in terms of a minimum duration and assume that the voltage is zero during that period.

IEEE surveys (see References [8], [18], and [21]) have revealed a wide variation in the minimum or *critical* service loss duration. Table 2 summarizes results for industrial plants, and Table 3 gives results for commercial buildings. It is clear from these tables that careful attention must be paid to choosing the proper interruption definition in any specific reliability evaluation.

Another important consideration in the economic evaluation of reliability is the time required to restart a plant or process following a power interruption. An IEEE survey (see Reference [8] and is also shown in Table 4) indicates that industrial plant restart time following a complete plant shutdown due to a power interruption averages 17.4 hours. The median plant restart time was found to be 4 hours. Clearly, specific data on plant or process restart time should be used if possible in any particular evaluation.

Many industrial plants reported that 1 to 10 cycles were considered critical interruption time, as compared to 1.39 hours, required for start up (plant outage time being considered equal to plant start-up time). This indicates that the critical factor must be carefully explored prior to assigning a cost to the interruption. Fifteen percent of the commercial buildings reported the critical service loss duration time to be 1 second or less, which is probably attributable to the fact that computer installations were involved.

Further data from Reference [8] graphically illustrates the time required to start an industrial plant after an interruption.

Thus, step 1 of the cost analysis becomes the selection of the *critical duration time* of the outage and the *plant start-up time*, including equipment repair or replacement time required because of the interruption.

2.2.1.2 Cost of an Electrical Service Interruption. With the establishment of expected downtime per interruption, costs are assigned to all individual items involved, including but not limited to:

- (1) Value of lost production time less expenses saved (expected restart time is used along with the repair or replacement time)
- (2) Damaged plant equipment
- (3) Spoiled or off-specification product

Table 2
Critical Service Loss Duration for Industrial Plants*

(Maximum length of time an interruption of electrical service will not stop plant production.)

25th Percentile	Median	75th Percentile	Average Plant Outage Time for Equipment Failure Between 1- and 10-Cycle Duration
10 cycles	10 s	15 min	1.39 h

*Fifty-five plants in the United States and Canada reporting; all industry.

Table 3
Critical Service Loss Duration for Commercial Buildings*

(Maximum length of time before an interruption to electrical service is considered critical.)

Service Loss Duration Time							
1 cycle (%)	2 cycles (%)	8 cycles (%)	1 s (%)	5 min (%)	30 min (%)	1 h (%)	12 h (%)
3	6	9	15	36	64	74	100

*Fifty-four buildings reporting; percentage of buildings with critical service loss for duration less than or equal to time indicated.

Table 4
Plant Restart Time*

(After service is restored following a failure that has caused a complete plant shutdown.)

Average (h)	Median (h)
17.4	4.0

*Forty-three plants in the United States and Canada reporting; all industry.

(4) Extra maintenance costs

(5) Cost for repair of failed component

If possible, the cost for each interruption of service should be expressed in a short interruption plus an amount of dollars per hour for the total outage time in order to utilize the reliability data and analysis presented.

2.2.1.3 Economic Evaluation of Reliability. There are many methods of varying degrees of complexity for accomplishing economic evaluations. For quick *order of magnitude* or *Is it worth further investigation?* type of evaluations, cost data from References [8] and [21] can be used. Caution must be exercised, however,

since these data are very general in nature, and wide variations are possible in individual cases. Some of the more commonly accepted methods for economic analyses are:

- (1) Revenue requirements (RR)
- (2) Return on investment (ROI)
- (3) Life cycle costing (LCC)

It is not the intent of this chapter to stipulate the method to be used nor the depth to which each analysis is to be made. These are considered to be the prerogative of the engineer and will depend heavily on management choice and the time available for the analysis. The revenue requirements (RR) method is given in this chapter as an example.

2.2.2 "Order of Magnitude" Cost of Interruptions. IEEE surveys (see References [9], [15], and [21]) present general data on the cost of interruptions to industrial plants and commercial buildings in the United States and Canada. Additional cost of interruption data is presented in various IEEE-IAS and IEEE-PES publications. A bibliography of these data is listed in Reference [5]. Other data are listed in References [4], [6], [13], and [19] and are primarily for areas in the middle of Canada and the Province of Ontario. The reader is again cautioned that such general data should be used only for "order of magnitude" evaluations where data specific to the system being studied are not available. A review of the reliability data can probably best be used in adjudicating the type of utility company service that should be provided.

The costs based on the kW interrupted and the kWh not delivered to industrial plants are presented in Tables 5 and 6.

Interruption costs based on kWh not delivered and reflecting the relationship to duration of interruptions for commercial buildings are presented in Tables 7 and 8.

Interruption costs as they are related to interruption time from Table 7 and from Reference [19] are graphically represented in Fig 6. Small industrials are

Table 5
Average Cost of Power Interruptions for Industrial Plants*

All plants	\$4.69/kW + \$6.65/kWh
Plants > 1000 kW max demand	\$2.60/kW + \$2.33/kWh
Plants < 1000 kW max demand	\$11.38/kW + \$20.11/kWh

*Forty-one plants in the United States and Canada reporting; published in 1973 with costs updated to July 1987.

Table 6
Median Cost of Power Interruptions for Industrial Plants*

All plants	\$1.71/kW + \$2.06/kWh
Plants > 1000 kW max demand	\$0.79/kW + \$0.89/kWh
Plants < 1000 kW max demand	\$9.13/kW + \$10.96/kWh

*Forty-one plants in the United States and Canada reporting; published in 1973 with costs updated to July 1987.

Table 7
Average Cost of Power Interruptions for Commercial Buildings

All Commercial Buildings*	\$14.65/kWh not delivered
Office Buildings Only	\$17.99/kWh not delivered

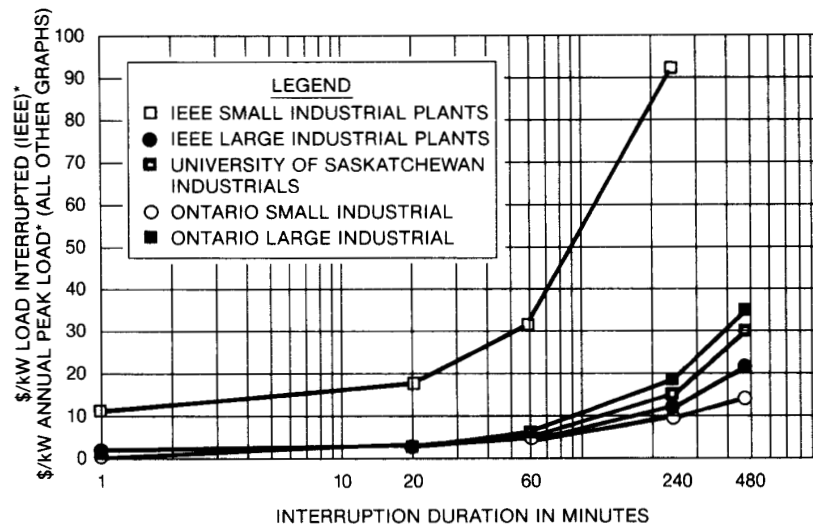
*Fifty-four buildings in the United States reporting; published in 1975 with costs updated to July 1987.

Table 8
Cost of Power Interruptions as a Function of Duration
for Office Buildings (with Computers)*

Power Interruptions	Sample Size	Maximum	Cost/Peak kWh Not Delivered Minimum	Average
15 min Duration	14	\$45.11	\$3.82	\$18.05
1 h Duration	16	\$50.61	\$3.82	\$16.85
Duration > 1 h	10	\$137.35	\$0.32	\$19.91

*Published in 1975 with costs updated to July 1987.

Fig 6
Cost of Interruption versus Duration



*All costs are updated to July 1987 and are in U.S. dollars.

considered to be those with a maximum demand of less than 1000 kW and large industrials are considered to be those with a demand of greater than 1000 kW.

2.2.3 Economic Analysis of Reliability in Electrical Systems. There are several acceptable methods for accomplishing an economic analysis of the reliability in electric systems. The examples of reliability analysis included in this chapter and Chapter 7 utilize the revenue requirements (RR) method. The application of this method as it applies to the analyses of the reliability in industrial plant electrical systems was presented in part 6 of Reference [9]. Applicable excerpts from this reference are included herein.

2.2.3.1 The Revenue Requirements (RR) Method. Although there are many ways in use to compare alternatives, some of these have defects and weaknesses, especially when comparing design alternatives in contrast to overall projects. The RR method is “mathematically rigorous and quantitatively correct to the extent permitted by accuracy with which items of cost can be forecast” (see References [9] and [18]).

The essence of the RR method is that, for each alternative plan being considered, the minimum revenue requirements (MRR) are determined. This means that we find out how much product we must sell to achieve minimum acceptable earnings on the investment involved plus all expenses associated with that investment. These minimum revenue requirements for alternative plans may be compared directly. The plan having the lowest MRR is the economic choice.

Minimum revenue requirements are made up of and equal to

- (1) Variable operating expenses
- (2) Minimum acceptable earnings
- (3) Depreciation
- (4) Income taxes
- (5) Fixed operating expenses

These minimum revenue requirements may be separated into two main parts, one proportional and the other not proportional to investment in the alternative. This may be expressed in an equation

$$G = X + CF \quad (\text{Eq 21})$$

where

- G = Minimum revenue requirements to achieve minimum acceptable earnings.
- X = Nonfixed or variable operating expenses.
- C = Capital investment.
- F = Fixed investment charge factor.

The last term in Eq 21, the product of C and F includes the items (2), (3), (4), and (5) listed in the preceding paragraph. Equation 21 will now be discussed.

X (Variable Expenses)—The effect of the failure of a component is to cause an increase in variable expenses. How serious this increase is depends to a great extent on the location of the component in the system and on the type of power distribution system employed. The quality of a component as installed can have a significant effect on the number of failures experienced. A poor quality component

installed with poor workmanship and with poor application engineering may greatly increase the number of failures that occur as compared with a high quality component installed with excellent workmanship and sound application engineering.

When a failure does occur, variable expenses are increased in two ways. In the first way, the increase is the result of the failure itself. In the second way, the increase is proportional to the duration of the failure.

Considering the first way, the increased expense due to the failure includes the following:

- (1) Damaged plant equipment
- (2) Spoiled or off-specification product
- (3) Extra maintenance costs
- (4) Costs for repair of the failed component

Considering the second way, plant downtime resulting from failures is made up of the time required to restart the plant, if necessary, plus the time to

- (1) Effect repairs, if it is a radial system, or
- (2) Effect a transfer from the source on which the failure occurred to an energized source

During plant downtime, production is lost. This lost production is not available for sale, so revenues are lost. However, during plant downtime, some expenses may be saved, such as expenses for material, labor, power, and fuel costs. Therefore, the value of the lost production is the revenues lost, because production stopped less the expenses saved. Some of the variable expenses may vary depending on the duration of plant downtime. For example, if plant downtime is only 1 hour, perhaps no labor costs are saved. But, if plant downtime exceeds 8 hours, labor costs may be saved.

If we assume that the value/hour of variable expenses does not vary with the duration of plant downtime, then the value of lost production can be expressed on a per hour basis, and the total value of lost production is the product of plant downtime in hours and the value of lost production per hour.

It should be noted that both the value of lost production and expenses incurred are proportional to the failure rate. The total effect on variable expenses, if the value of lost production is a constant on a per hour basis, may be expressed in the following equation:

$$X = \lambda [x_i + (g_p - x_p)(r + s)] \quad (\text{Eq 22})$$

where

- X = Variable expenses (\$ per year).
- λ = Failures per year or failure rate.
- x_i = Extra expenses incurred per failure (\$ per failure).
- g_p = Revenues lost per hour of plant downtime (\$ per hour).
- x_p = Variable expenses saved per hour of plant downtime (\$ per hour).
- r = Repair or replacement time after a failure (or transfer time if not radial system), in hours.
- s = Plant start-up time after a failure, in hours.

Assume that

- λ = 0.1 failure per year.
- x_i = \$40 000 per failure, extra expenses incurred.
- g_p = \$16 000 per hour, revenues lost.
- x_p = \$12 000 per hour, expenses saved.
- r = Ten hours per failure.
- s = Twenty hours per failure.

Then, variable expenses affected would be

$$X = (0.1) [\$40\,000 + (\$16\,000 - \$12\,000)(10 + 20)] = \$16\,000 \text{ per year}$$

The term g_p represents revenues lost, and it is not really an expense. However, it is a negative revenue, and as such has the same effect on the economics as a positive expense item. It is convenient to treat it as though it were an expense.

A failure rate of 0.1 failure per year is equivalent to a mean time between failures of 10 years. Since we are dealing with probability, this is what we can expect, but in a specific case, we might have two failures in one 10 year period and no failures in another 10 year period. But considering many similar cases, we expect to have an average of 0.1 failure per year, with each failure costing an average of \$160 000. This gives an equal average amount per year in the above example of \$16 000.

The point is that even though the actual failures cost \$160 000 each and occur once every 10 years, a given failure is just as likely to occur in any of the 10 years. The equivalent equal annual amount of \$16 000 per year is the average value of one failure in 10 years.

C (Investment)—Each different alternative in an industrial plant power distribution system involves different investments. The system requiring the least investment will usually be some form of radial system. By varying the type of construction and the quality of the components in the system, the investment in radial systems can vary widely.

The best method is to find one total investment in each alternative plan. Another common method is to find the incremental investment in all alternatives over a base or least expensive plan. The main reason that the total investment method is preferable is that, in comparing alternatives, the investment is multiplied by an F factor (which will be explained later). This factor is usually the same for alternative plans of the sort being considered here, but this is not necessarily the case.

Using the incremental investment may thus introduce a slight error into the economic comparisons.

F (Investment Charge Factor)—This discussion of the investment charge factor is taken from Reference [9].

The F factor includes the following items, which are constant in relation to the investment:

- (1) Minimum acceptable rate of return on investment, allowing for risk
- (2) Income taxes
- (3) Depreciation
- (4) Fixed expenses

An equation to calculate the F factor is:

$$F = \left[\frac{(S_c a_L / f_r) - t \bar{d}_t}{1 - t} \right] + e \quad (\text{Eq 23})$$

This may also take the following form:

$$F = \bar{r} + \bar{d} + \bar{t} + e \quad (\text{Eq 24})$$

where

$a_n = R + d_n$, amortization factor or leveling factor.

$d_n = R / (S_n - 1)$, sinking fund factor.

$S_n = (1 + R)^n$, growth factor or future value factor.

n = Period of years, such as c or L .

c = Years prior to start up that an investment is made.

L = Life of investment years.

R = Minimum acceptable earnings per \$ of C (investment).

f_r = Probability of success or risk adjustment factor.

t = Income taxes per \$ of C (investment).

$\bar{d}_t$ = Income tax depreciation, leveled per \$ of C (investment) = $1 / L$, $\bar{d}_t = 1/L$.

e = Fixed expenses per \$ of C (investment).

$\bar{r}$ = Levelized return on investment per \$ of C (investment).

$\bar{d}$ = Levelized depreciation on investment per \$ of C (investment).

$\bar{t}$ = Levelized income taxes on investment per \$ of C (investment).

Assume

L = Twenty years (life of investment).

c = One year.

R = 0.15 (minimum acceptable rate of return).

f_r = 1 (risk adjustment factor).

t = 0.5 (income tax rate).

$\bar{d}_t = 1 / L = 0.05$.

$e = 0.0825$.

then

$$S_c = (1 + R)^c = (1 + 0.15)^1 = 1.15$$

$$S_L = (1 + R)^L = (1 + 0.15)^{20} = 16.37$$

$$d_L = (R / S_L - 1) = 0.15 / (16.37 - 1) = 0.0098$$

$$a_L = (R + d_L) = 0.15 + 0.0098 = 0.1598$$

Substituting into Eq 23 to calculate the F factor, we get

$$F = \left[\left(\frac{(1.15)(0.1598)}{1.0} - (0.5)(0.05) \right) \right] + 0.0825 = 0.04 \quad (\text{Eq 25})$$

All the assumed values are believed to be typical for the average electrical distribution system, except the value of $e = 0.0825$. This latter value was arbitrarily assumed in order to make R round out to 0.4. The term e covers such items as

insurance, property taxes, and fixed maintenance costs. A typical value for e is probably less than 0.0825.

It is believed that a typical value for minimum acceptable return on investment in many industrial plants is 15%, that is, $R = 0.15$. The company's average rate of return, based on either past history or anticipated results, is a measure of what R should be. In plants of higher risk than the average, the risk adjustment factor, f_r , should probably be less than 1. However, company management determines what the value of R should be.

The value of F can be calculated from Eq 23. In Reference [8], tabular values are given for the factors S_n and a_n for various rates of return and plant lives.

2.2.3.2 Steps for Economic Comparisons

- (1) Prepare single-line diagrams of alternative plans and assign failure rates, repair times, and investment in each component, and then determine the total investment C in each plan.
- (2) Determine X , the increased variable expense for each plan as the sum of the value of lost production and the extra variable expenses incurred.
- (3) Determine F , the fixed investment charge factor F from Eq 23.
- (4) Calculate $G = X + CF$, the minimum revenue requirements G of each plan from Eq 21.
- (5) Select as the economic choice the plan having the lowest value of G .

2.2.3.3 Conclusions. A technique has been presented for the economic evaluation of power system reliability. The method of determining the failure rates and repair times of different alternatives is not covered here. Additional information relative to the RR method is included in Reference [18].

2.2.4 Examples. Examples of electrical systems with varying degrees of reliability (availability), together with fixed and variable costs are given in Chapter 7.

2.2.5 Worth of Improved Reliability in Electrical Components. All of the data and examples presented in this chapter utilize failure rates and average repair time data for standard electrical components. Unfortunately, industry and commercial standards for recording failure history are very unsophisticated and do not allow differentiation between various grades of equipment or between different manufacturers.

A summary of several studies on the worth of improved reliability and of reduced maintenance costs for high-voltage circuit breakers is given in Reference [14], which is included as Appendix J in this book. These studies were made by a working group in CIGRE (Conference Internationale des Grand Reseaux Electriques a² Haute Tension), which is a technical arm of the International Electrotechnical Commission (IEC). In addition, this CIGRE working group has made a worldwide survey that collected and published all of the necessary reliability data and maintenance cost data that are needed in order to make studies on the worth of improved reliability and reduced maintenance costs of high-voltage circuit breakers. A summary of this data is given in Reference [14].

2.3 Cost of Scheduled Electrical Preventive Maintenance. In the economic evaluation of reliability, it is always appropriate to consider the costs of scheduled electrical preventive maintenance. Sometimes these costs are large enough to make

it desirable to analyze them separately when comparing alternative designs of industrial power systems. The revenue requirements (RR) method described in 2.2.3.1 includes a term called the "investment charge factor (F)" which is given by Eq 23 in 2.2.3.1 and includes e (the fixed yearly expenses) as a percentage of the capital investment. Both F and e are attributed to scheduled electrical preventive maintenance, insurance, property taxes, etc. Since the yearly average costs for scheduled electrical preventive maintenance may not be the same percentage of investment for every component within the industrial power system, a separate more detailed look is often taken at these costs for each component.

Scheduled electrical preventive maintenance has two major cost elements: labor effort and spare parts consumed. These costs are often expressed on an average yearly basis so as to be usable with the RR method when an economic evaluation is made. These data are needed for each different type of component used in the industrial power system and can be compiled for each component as follows:

- (1) Labor costs in manhours per component per year
- (2) Cost of spare parts consumed in dollars per component per year
- (3) Labor rate in dollars per manhour

If, for example, a component is only maintained once every 3 years, then its maintenance costs should be divided by 3 in order to determine the average yearly maintenance cost. The labor rate used should probably only include the overhead costs associated with the storage of spare parts, direct supervision of maintenance, and the costs for the necessary test equipment. The labor costs in dollars per component per year can be calculated by multiplying items (1) and (3) together; the result can then be added to item (2) to get the total average yearly costs that are attributable to scheduled electrical preventive maintenance.

Data thus collected can become obsolete at a later date due to inflation that can result in changing the labor rate used and also the average yearly cost of spare parts consumed. But the data for labor in manhours per component per year does not become obsolete due to inflation. Some engineers have chosen to use their labor rate to convert their average yearly cost data for spare parts consumed into average yearly "equivalent manhours" data. This is then added to the labor manhours data to get total equivalent manhours per component per year that includes both the labor cost and the cost of spare parts consumed. The use of equivalent manhours for cost data instead of dollars has two advantages

- (1) The equivalent manhours data do not become obsolete due to inflation.
- (2) The equivalent manhours data can be considered an international currency. The data are not affected by changing exchange rates between different currencies or countries. This enables the cost data to be easily compared with studies from other countries.

Component data on the cost of scheduled electrical preventive maintenance are not included in this book except for the data on high-voltage circuit breakers above 63 kV collected by a CIGRE working group (see Reference [14]), which is included in this book as Appendix J. It would be desirable to have such data for all of the electrical equipment categories listed in Table 10 of Chapter 3. It would then be possible to consider the cost of scheduled electrical preventive maintenance in design decisions of the industrial power system by adding this into the MRR method.

2.4 Effect of Scheduled Electrical Preventive Maintenance on Failure Rate. One of the important total operating cost decisions made by the management of an industrial plant is how much money to spend for scheduled electrical preventive maintenance. The amount of maintenance performed on a component can affect its failure rate. Very little quantitative data have been collected and published on this subject. Yet this is an important factor when attempting to study the total owning costs of a complete power system. If the maintenance effort is reduced, the maintenance costs go down. This may increase the failure rate of the components in the power system and raise the costs associated with failures. There is an optimum amount of maintenance for minimum total owning cost of a complete power system.

The subject of electrical preventive maintenance is discussed in Chapter 5. Some data are shown in Tables 43 and 44 on the effect of the frequency and quality of scheduled electrical preventive maintenance. These data have been used to calculate the effect of maintenance quality on the failure rate of transformers, circuit breakers, and motors shown in Table 45. Unfortunately, the data do not relate the amount or cost of component maintenance to the failure rate.

The effect of the cost of component scheduled electrical preventive maintenance on failure rate has not been included in this book. More industry studies and published data are needed on this subject, like the example described next.

2.4.1 Example. A paper containing quantitative data and analysis of optimum maintenance intervals has been published (see Reference [23]). This work was based upon 10 000 failures collected at the author's company over a period of 7 years for 23 categories of electrical equipment. Included in this paper was a description of just what failures could be prevented by maintenance. Actual data were used to determine how this failure rate varied with the maintenance interval. The optimum maintenance interval was then determined based upon the maintenance cost and the cost of failures/power outages. Failures that could be prevented by diagnostic testing were then studied in a similar manner to those that could be prevented by maintenance. The optimum diagnostic interval was then calculated for 15 equipment categories based upon the cost of diagnostic testing and the cost of failures/power outages.

It was reported that 25% of the failures could have been prevented by maintenance, and additional failures could have been prevented by diagnostic testing.

2.5 References. The information in this chapter shall be used in conjunction with the following publications:

NOTE: References [16], [17], [15], and [21], respectively, are reprinted in Appendixes A, B, C, and D. References [5] and [19] are reprinted in Appendix M. Reference [14] is reprinted in Appendix J.

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Chapter 3

Summary of Equipment Reliability Data

3.1 Introduction. This chapter summarizes the reliability data collected from electrical equipment reliability surveys over a period of 30 years. The chapter is divided into two parts consisting of recent equipment surveys conducted between 1976 and 1989 (i.e., Part 1) and equipment surveys conducted prior to 1976 (i.e., Part 2). Detailed reports on the surveys are given in the appendixes and references. The results of these surveys are discussed and compared. Detailed information contained in the other chapters of this book and pertinent to equipment reliability data is referenced in this chapter. Detailed lists of references on equipment reliability are presented in the appendixes and at the end of this chapter.

A knowledge of the reliability of electrical equipment is an important consideration in the design and operation of industrial and commercial power distribution systems. The failure characteristics of individual pieces of electrical equipment (i.e., components) can be partially described by the following basic reliability statistics:

- (1) Failure rate, often expressed as failures per year per component (failures per unit-year)
- (2) Downtime to repair or replace a component after it has failed in service, expressed in hours (or minutes) per failure
- (3) In some special cases, probability of starting (or operating) is used

Reliability data on the pertinent factors (e.g., cause and type of failures, maintenance procedures, repair method, etc.) is also required to practically characterize the performance of electrical equipment in service. (Refer to Appendixes A and B.)

The reliability performance of industrial and commercial electrical power distribution systems (e.g., economic operation, frequency and duration of equipment and system outages, etc.) can be estimated from a knowledge of the reliability data of individual electrical parts (i.e., components) that are interconnected to form an operating system. The analytical models required for estimating the reliability of various power system configurations are presented in Chapters 2 and 8. Based on the results of these analytical models, the cost of interruptions can be estimated and used in the reliability cost/reliability worth methodology presented in Chapter 7 and Appendix C. The cost of power interruptions to industrial plants and commercial buildings is summarized in Chapter 2.

Electrical equipment reliability data is normally obtained from field surveys of individual industrial and commercial equipment failure reports. The reason for conducting a survey is to provide answers to critical questions pertaining to the failure characteristics of electrical equipment in industrial and commercial installations.

Each survey has a defined objective of obtaining field data on electrical equipment failure characteristics and this determines the form of the questionnaires that are sent to various respondents.

An analysis of the survey returns may or may not provide answers to all the questions posed in the questionnaire. The significance of the survey data obtained is dependent upon many factors, for example, the number of equipment failures reported, their operating history, the survey questionnaire, etc. There will undoubtedly be new questions raised and also some old questions and controversies left unresolved. Items found to be of little significance will be omitted and the survey form simplified to maximize the response for the next survey. The procedure for conducting the survey is given in Appendix F. Information on the determination and analysis of data for reliability studies is presented in Reference [16].²

The IEEE Industry Applications Society (IAS) has a continuing program to conduct surveys on the reliability of electrical equipment in industrial and commercial installations (see References [6], [9] - [13], and [15]). The most significant results from these surveys are then summarized for inclusion in a future revision of this standard.

As in previous survey reports, this chapter maintains the standard for credibility of failure rates by identifying categories that contain an insufficient number of failures. If there were less than eight failures, an * is used to indicate a small sample size. It is believed that a minimum of eight field failures is necessary to have a reasonable chance of estimating the failure rate or the average downtime per failure to within a factor of 2 (see Appendix A, Part 1 for details). Both the average downtime per failure data and median downtime per failure data are given so that the effect of a few very long outages on the average downtime can be indicated by a large difference between the average and median values.

An equipment reliability reference guide is shown in Table 9. For each electrical component presented in this chapter, the tables and appendixes that contain reliability data pertinent to that component are presented. Table 10 contains a summary of the failure rate and average and median downtime per failure data for all electrical equipment surveyed. These values are suggested for use in the absence of better data not being available from the reader's own experience.

²The numbers in brackets correspond to those in the references at the end of this chapter.

Table 9
Equipment Reliability Reference Guide

Electrical Equipment		Reference Tables in Chapter 3										Appendixes	
		Part 1				Part 2							
		Surveys 1976-89				Surveys Prior to 1976							
Motors	> 50 hp	32				—	—	—	—	—	41	—	A, B, H
	> 200 hp	23-31				—	—	—	—	—	41	—	
	> 250 hp	33				—	—	—	—	—	41	—	
Motor Starters		—				—	36	37	38	39	41	42	A, B
Generators		12				—	—	—	—	—	41	—	A, B, L
Transformers	Power	13	15	16	17	—	—	—	—	—	41	42	A, B, G
		18	19	20	21								
	Rectifier	14	16	17	18	—	—	—	—	—	41	42	
		19	20	22	—								
Circuit Breakers		—				35	—	37	38	39	41	42	A, B, J, K
Disconnect Switches		—				—	36	37	38	39	41	42	A, B
Bus Duct		—				—	36	37	38	39	41	—	A, B
Switchgear	Bus Insulated	11				—	—	—	—	—	41	—	A, B, E
	Bus Bare	11				—	—	—	—	—	41	—	
Open Wire		—				—	36	37	38	39	41	42	A, B
Cable		—				—	36	37	38	39	41	42	A, B, I
Cable Joints		—				—	36	37	38	39	41	42	
Cable Terminations		—				—	36	37	38	39	41	42	
Electric Utility Power Supplies		—				—	—	—	—	40	41	—	A, B, D

Table 10
Summary of Optional Failure Rate and Average and Median Downtime
per Failure for All Electrical Equipment Surveyed

Equipment	Equipment Subclass	Failure Rate (Failures per Unit-Year)	Actual Hours of Downtime per Failure	
			Industry Average	Median Plant Average
Transformers	Liquid Filled — All	0.0062	356.1 ¹	—
	300–10 000 kVA	0.0059	297.4 ¹	—
	10 000+ kVA	0.0153	1178.5 ¹	—
Rectifier Transformers	Liquid Filled 300–10 000 kVA	0.0153	1664.0 ¹	—
Motors > 200 hp ⁶	Induction 0–1000 V	0.0824	42.5	15.0
	1001–5000 V	0.0714	75.1	12.0
	Synchronous 1001–5000 V	0.0762	78.9	16.0
Circuit Breakers ³	Fixed (Including Molded Case) — All	0.0052	5.8	4.0
	0–600 V — All Sizes	0.0042	4.7	4.0
	0–600 A	0.0035	2.2	1.0
	Above 600 A	0.0096	9.6	8.0
	Above 600 V ³	0.0176	10.6	3.8
	Metalclad Drawout Type — All	0.0030	129.0	7.6
	0–600 V — All Sizes	0.0027	147.0 ²	4.0
	0–600 A	0.0023	3.2	1.0
	Above 600 A	0.0030	232.0	5.0
	Above 600 V ³	0.0036	109.0 ²	168.0
Motor Starters	Contact Type: 0–600 V	0.0139	65.1	24.5
	Contact Type: 601–15 000 V	0.0153	284.0	16.0
Generators	Continuous Service Steam Turbine Driven	0.1691	32.7	—
	Emergency and Standby Units Reciprocating Engine Driven			
	Rate per Hour in Use (0.00536) Failures per Start Attempt (0.0135)		478.0	—
Disconnect Switches	Enclosed	0.006100	1.6	2.8
Switchgear Bus — Indoor and Outdoor ⁴	Insulated: 601–15 000 V	0.001129	261.0	28.0
	Bare: 0–600 V	0.000802	550.0	27.0
	Bare: Above 600 V	0.001917	17.3	36.0
Bus Duct — Indoor and Outdoor (Unit = 1 Circuit Ft)	All Voltages	0.000125	128.0	9.5
Open Wire (Unit = 1000 Circuit Ft)	0–15 000 V	0.01890	42.5	4.0
	Above 15 000 V	0.00750	17.5	12.0

Table 10 (continued)

Equipment	Equipment Subclass	Failure Rate (Failures per Unit-Year)	Actual Hours of Downtime per Failure	
			Industry Average	Median Plant Average
Cable — All Types of Insulation (Unit = 1000 Circuit Ft) ⁵	Above Ground and Aerial			
	0-600 V	0.00141	457.0	10.5
	601-15 000 V—All	0.01410	40.4 ²	6.9
	In Trays Above Ground	0.00923	8.9	8.0
	In Conduit Above Ground	0.04918	140.0	47.5
	Aerial Cable	0.01437	31.6	5.3
	Below Ground and Direct Burial			
	0-600 V	0.00388	15.0	24.0
	601-15 000 V—All	0.00617	95.5 ¹	35.0
Cable (Unit = 1000 Circuit Ft)	In Duct or Conduit	0.00613	96.8	35.0
	Above 15 000 V	0.00336	16.0	16.0
	601-15 000 V			
	Thermoplastic	0.00387	44.5	10.0
	Thermosetting	0.00889	168.0	26.0
Cable Joints — All Types of Insulation	Paper Insulated Lead Covered	0.00912	48.9	26.8
	Other	0.01832	16.1	28.5
	601-15 000 V			
Cable Joints ⁵	In Duct or Conduit Below Ground	0.000864	36.1	31.2
	601-15 000 V			
	Thermoplastic	0.000754	15.8	8.0
Cable Terminations ⁵ — All Types of Insulation	Paper Insulated Lead Covered	0.001037	31.4	28.0
	Above Ground and Aerial			
	0-600 V	0.000127	3.8	4.0
	601-15 000 V—All	0.000879	198.0	11.1
	Aerial Cable	0.001848	48.5	11.3
Cable Terminations	In Trays Above Ground	0.000333	8.0	9.0
	In Duct or Conduit Below Ground			
	601-15 000 V	0.000303	25.0	23.4
Miscellaneous	601-15 000 V			
	Thermoplastic	0.004192	10.6	11.5
	Thermosetting	0.000307	451.0	11.3
	Paper Insulated Lead Covered	0.000781	68.8	29.2
Miscellaneous	Inverters	1.254000	107.0	185.0
	Rectifiers	0.038000	39.0	52.2

NOTES: (1) See Tables 13 and 14 in this chapter for data comparing replacement time with average repair time of transformers.

(2) See Tables 50, 51, 55, and 56 in Appendix B for results on a special study on the effects of failure repair method and failure repair urgency on the average hours downtime per failure.

(3) See Appendix J for circuit breakers above 63 kV from a CIGRE 13-06 worldwide survey. See Appendix K for a later small IEEE survey.

(4) Units = the number of connected circuit breakers and connected switches.

(5) See Appendix I for utility industry data on underground cable, terminations, and splices.

(6) See Table 32 for motors > 50 hp.

3.2 Part 1: Recent Equipment Reliability Surveys (1976-89)

3.2.1 1979 Switchgear Bus Reliability Data. The reliability of switchgear bus in industrial and commercial applications was investigated in a 1979 survey [11] (see Appendix E), and the summarized failure rate and median outage duration time for the various subcategories of equipment are shown in Table 11. In this survey, the term “units” for a bus is defined as the total number of connected circuit breakers and connected switches. In the previous survey in 1974, the term “units” included the total number of connected circuit breakers or instrument transformer compartments. The total number of plants in the 1979 survey response was considerably greater than the 1974 survey; however, the unit-year sample size was slightly less.

Table 11
Switchgear Bus—Indoor and Outdoor
1979 Survey Data

Industry	Equipment Subclass	Failure Rate (Failures per Unit-Year)	Median Hours Downtime per Failure
All	All	0.001050	28
All	Insulated, Above 600 V	0.001129 (0.001700)	28 (26.8)
All	Bare, All Voltages	0.000977	28
All	Bare, 0-600 V	0.000802 (0.000340)	27 (24.0)
All	Bare, Above 600 V	0.001917 (0.000630)	36 (13.0)
Petroleum/Chemical	Insulated, Above 600 V	0.002020	40
Petroleum/Chemical	Bare, All Voltages	0.002570	28
Petroleum/Chemical	Bare, 0-600 V	0.002761	22
Petroleum/Chemical	Bare, Above 600 V	*	48

NOTES: *Small sample size, less than eight failures.

(1) Number in parentheses = The result from the 1974 survey.

The 1974 survey generated some controversy concerning bare and insulated buses. As can be seen from Table 11, insulated bus equipment showed a significantly higher failure rate than bare bus above 600 V. An analysis of the 1974 data base revealed that the majority of the data collected came from the petroleum/chemical industry. In the 1979 survey, the petroleum/chemical industry data was separated from the remaining industrial data base and indicated that the number of reported failures in each category was dominated by the petroleum/chemical industry. The bare bus failure was significantly higher and the insulated bus failure rate lower in the 1979 survey than in the 1974 survey.

A comparison of the median downtime per failure in both surveys revealed no significant differences. It is important to emphasize that the duration of an outage is dependent on many factors, and, without supplementary information on the operating procedures, maintenance type, spare parts inventory, etc., the data in these surveys should be viewed as general information.

Some important additional observations based on the 1979 survey are:

- (1) Newer bus appears to experience a higher failure rate than older bus. This may be partly explained by improper installation, type of construction of new switchgear, etc., but is not completely consistent with the observation that failure rates are highly dependent on maintenance.
- (2) Outdoor bus shows a higher failure rate than indoor bus.
- (3) Primary and contributing causes of failures were investigated. Inadequate maintenance was one of the leading "suspected primary causes of failure" and exposure to contaminants (including dust, moisture, and chemicals) was the leading "contributing cause to failure." This tends to support the data showing outdoor bus with a relatively high failure rate.
- (4) The survey results on type of failures show a surprisingly high percentage of line-to-line failures, rather than line-to-ground.

3.2.2 1980 Generator Survey Data. The results of the 1980 generator survey data (see Reference [10]) are summarized in Table 12. A "unit" in this survey was defined to include the generator's driver and its ancillary equipment, including the device from which the generator's output is made available to the "outside" world. The term "unit-year" was defined as the summation of the running times reported for each generator.

Table 12
1980 Generator Survey Data

Equipment Subclass	Average Hours Downtime per Failure	Failure Rate
Continuous Service		
Steam Turbine Driven	32.7	0.16900 failures per unit year
Emergency and Standby Units		
Reciprocating Engine Driven	478.0	0.00536 failures per hour in use
Reciprocating Engine Driven	*	0.01350 failures per start attempt

NOTES: *Small sample size; less than eight failures.

(1) Appendix L contains data from a recent survey of diesel and gas turbine generators, 600 - 1800 kW.

Two major categories (i.e., continuously applied units and emergency or standby applied units) emerged from an evaluation of the responses. All of the continuous units were steam turbine driven, and all of the emergency or standby units were reciprocating engine driven. An important point to note on the data for emergency and standby units: Failure to start for automatically started units was counted as a failure; whereas failure to start for manually started units was not counted as a failure.

3.2.3 1979 Survey of the Reliability of Transformers. A survey published in 1973 - 74 raised some interesting questions and created some controversy (see References [8] and [23]). The most controversial items in this survey concerned: (1) the average outage duration time after a transformer failure, in relation to the failure repair method, and (2) the comparatively high failure rate for rectifier transformers.

The 1979 survey form (see Reference [12]) was improved considerably, taking lessons learned from the 1973-74 version. Items felt to be of little significance in the past have been omitted, and the form was simplified to maximize the response. Data relating specifically to transformer reliability, such as rating, voltage, age, and maintenance, were included in the new form. The most significant categories in the failed unit data are: the causes of the failure, the failure repair method, failure repair urgency and the duration of the failure, and the age at time of the failure. The survey form of the 1979 survey (published in 1983) is shown in Appendix G.

3.2.3.1 Failure Rate and Failure Repair Method for Power and Rectifier Transformers Survey Results. The survey response for power transformers is summarized in Table 13 and for rectifier transformers is summarized in Table 14.

Table 13
Power Transformers (1979 Survey)

Equipment Subclass	Failure Rate (Failures per Unit-Year)	Average Repair Time (Hours per Failure)	Average Replacement Time (Hours per Failure)
All Liquid Filled	0.0062	356.1	85.1
Liquid Filled 300-10 000 kVA	0.0059	297.4	79.3
Liquid Filled > 10 000 kVA	0.0153	1178.5*	192.0*
Dry 300-10 000 kVA	*	*	*

*Small sample size; less than eight failures.

Table 14
Rectifier Transformers (1979 Survey)

Equipment Subclass	Failure Rate (Failures per Unit-Year)	Average Repair Time (Hours per Failure)	Average Replacement Time (Hours per Failure)
All Liquid Filled	0.0190	2316.0	41.4
Liquid Filled 300-10 000 kVA	0.0153	1664.0*	38.7*
Liquid Filled > 10 000 kVA	*	*	*

*Small sample size; less than eight failures.

The survey results for the liquid-filled power transformers compared favorably between the 1973-74 and 1979 surveys: 0.0041 and 0.0062 failures per unit-year, respectively. The 1979 survey also confirmed the fact that the failure rate for rectifier transformers (i.e., 0.0190) is much higher than those for the other transformer categories (i.e., 0.0062). This may be due to the severe duties to which they were subjected and/or the harsh environments in which they are housed.

Tables 13 and 14 include data on average outage duration time versus the failure repair method. The data clearly indicates that the restoration of a unit to service by repair rather than replacement results in a much longer average outage duration time. This is consistent with previous survey results. Despite this fact, in most categories a larger number of units were restored to service by repair. These results show the obvious benefits in having spares at the site or readily available. The data also provides some of the information necessary in the preparation of an economic justification for spares. The averages shown represent only those cases where restoration work was begun *immediately*. Those instances in which the repair or replacement was deferred were excluded to avoid distorting the average outage duration time data.

3.2.3.2 Failure Rate versus Age of Power Transformers. The survey response for power transformer failures as a function of the transformer's age is summarized in Table 15.

Table 15
Failure Rate versus Age of Power Transformers (1979 Survey)

Equipment Subclass	Age ¹ (Years)	Number of Units	Sample Size (Unit-Years)	Number of Failures ²	Failure Rate (Failures per Unit-Year)
Liquid Filled 300-10 000 kVA	1-10	638	2625.5	19	0.0072
Liquid Filled 300-10 000 kVA	11-25	715	8846.5	47	0.0053
Liquid Filled 300-10 000 kVA	> 25	397	5938.0	36	0.0060
Liquid Filled > 10 000 kVA	1-10	27	144.0	0*	—
Liquid Filled > 10 000 kVA	11-25	28	283.5	7*	0.0246*
Liquid Filled > 10 000 kVA	> 25	9	158.0	2*	0.0126*

NOTES: *Small sample size; less than eight failures.

(1) Age was the age of the transformer at the end of the reporting period.

(2) Relay or tap changer faults were not considered in calculation of failure rates or repair and replacement times.

An examination of Table 15 reveals that the failure rates for power transformers was approximately equal in all three age groups. It can be seen that slightly higher failure rates for transformer units aged 1 to 10 years and for units greater than 25 years may be attributable to "infant mortality" and to units approaching the end of their life, respectively.

3.2.3.3 Failure-Initiating Cause. Table 16 summarizes the *failure-initiating cause* data for power and rectifier transformers. This table reveals that a large percentage of transformer failures were initiated by some type of insulation breakdown or transient overvoltages.

Table 16
Failure-Initiating Cause for Power and Rectifier Transformers (1979 Survey)

Failure-Initiating Cause	All Power Transformers		All Rectifier Transformers	
	Number of Failures ¹	Percentage	Number of Failures	Percentage
Transient Overvoltage Disturbance (Switching Surges, Arcing Ground Fault, etc.)	18	16.4%	2	13.3%
Overheating	3	2.7	1	6.7
Winding Insulation Breakdown	32	29.1	2	13.3
Insulation Bushing Breakdown	15	13.6	1	6.7
Other Insulation Breakdown	6	5.5	3	20.0
Mechanical Breaking, Cracking, Loosening, Abrading, or Deforming of Static or Structural Parts	8	7.3	3	20.0
Mechanical Burnout, Friction, or Seizing of Moving Parts	3	2.7	2	13.3
Mechanically Caused Damage from Foreign Source (Digging, Vehicular Accident, etc.)	3	2.7	0	0.0
Shorting by Tools or Other Metal Objects	1	0.9	0	0.0
Shorting by Birds, Snakes, Rodents, etc.	3	2.7	0	0.0
Malfunction of Protective Relay Control Device or Auxiliary Device	5	4.6	0	0.0
Improper Operating Procedure	4	3.6	0	0.0
Loose Connection or Termination	8	7.3	1	6.7
Others	1	0.9	0	0.0
Continuous Overvoltage	0	0.0	0	0.0
Low Voltage	0	0.0	0	0.0
Low Frequency	0	0.0	0	0.0
	110	100.0%	15	100.0%

NOTE: (1) Failure-initiating cause not specified for two failures.