THE WORK IN THIS THESIS IS RESPECTFULLY

DEDICATED TO MY MOTHER SMT. AMRIT KAUR GROVER.

RELIABILITY EVALUATION IN SUBSTATION, SWITCHING STATION AND DISTRIBUTION SYSTEMS

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by

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ABSTRACT

The reliability performance of transmission and distribution systems can be evaluated in quantitative terms by the application of probability methods. This thesis develops a simple and sequential approach for the reliability analysis of practical systems. A cut set approach is utilized to form series-parallel representations of complex system configurations. A consistent set of equations is used in conjunction with the cut set approach to evaluate the outage frequency and duration indices at different load points in the system. The failures of individual power system components may have quite different effects on the total system. In this thesis, component failures are modelled with regard to their system effects. This method of modelling provides a more accurate representation of component and system behaviour. Reliability analysis of practical systems often requires complex and time consuming computations. A digital computer program has been developed to minimize the labour involved. The program output provides a concise and orderly description of the various combinations of events within the system that could result in an interruption. System reliability can be improved by the judicious selection of maintenance policies. This thesis illustrates that maintenance policies cannot be determined solely by qualitative considerations. Reliability benefits associated with a component co-ordinated maintenance policy are quantitatively evaluated. The cut set approach is extended to the evaluation of frequency and duration of overloads utilizing two additional indices of interrupted load and energy to estimate the overload severity. The application of supply interruption costs in the evaluation of economically justified investment is illustrated in this thesis. The savings in the costs of supply interruptions obtained by the use of spare transformers, standby units, additional facilities etc. can then be compared utilizing these techniques, with the investment in these facilities.

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1. INTRODUCTION

The demand for electric power by our society has been growing at a rate of about 7% per annum. In the face of this growth rate, power utilities are constantly confronted with the problem of satisfying the needs of their customers as economically as possible and with a reasonable level of continuity and quality. The general public in North America has grown accustomed to a very high quality of electric supply. Both industry and households have based their operation on this highly reliable service. The determination of "how reliable the service should be?" has been and will always be of considerable concern to power system engineers and managers. Power systems contain, by design, many redundant elements strictly for the purpose of increasing the assurance of continuity and the provision of high quality service to the customer. Redundancy is provided in many forms such as generating capacity reserve margins, interconnection with neighbouring utilities, additional transmission and distribution elements and the simple or complex alternate supply facilities which exist in virtually all functional areas in some form or another. These facilities exist because the basic system design philosophy recognizes and therefore, anticipates the possibility of equipment failure and the need to remove equipment from service for preventive maintenance.

This overall aspect of power system planning, design and operation is often loosely designated as "reliability". This word is used in a multitude of ways to indicate the ability of the system to perform its intended function. In the area of transmission and distribution system evaluation, qualitative methods are generally used to describe system reliability performance. These methods are based on certain rules of thumb and do not adequately reflect the effect of equipment performance characteristics, network configuration, system operating conditions and in fact those elements that do influence the system reliability. These factors can be incorporated in the analysis only through quantitative reliability techniques. Quantitative methods provide a consistent measure of system adequacy and enable the planning engineer to compare reliability levels associated with alternate planning proposals.

The increasing awareness of the need for quantitative methods of power system reliability evaluation is evident from the several important publications(1) which have appeared in this regard. The bulk of the publications deal with the evaluation of generating capacity adequacy. The first publication on this subject appeared almost forty years ago. The application of probability methods to distribution system design also extend over a period almost equal to that of generation capacity evaluation. However, there appears to have been only a minimal amount of continuous activity in the transmission and distribution area until about 1964. The published literature clearly indicates the increased emphasis, within the past few years, on the quantitative evaluation of transmission and distribution system reliability. One of the main objectives in virtually all the publications has been the development of accurate and consistent models to represent the true component and system behaviour. This thesis provides a further step towards this objective. The emphasis is on the development, modifications and applications of the techniques and models. In this regard, this work is a direct continuation of the author's M.Sc. thesis(8). The main features of the thesis are outlined in the following paragraphs.

The Markov approach(5,6) is considered to be the most accurate method of modelling the performance of power system components, provided the necessary distributional assumptions are valid. The application of this technique becomes quite cumbersome as the number of system components increases. The computations for the evaluation of state probabilities involve a large amount of effort if dependent effects such as environmental conditions, maintenance requirements etc. are to be considered. The author's M.Sc. thesis(8) developed a consistent set of equations for the evaluation of sustained, temporary, maintenance and overload outage indices. The results obtained from the equations compare reasonably well with those predicted by a Markov approach. This thesis illustrates a sequential and straightforward technique in which the simple set of equations is used in conjunction with a cut set approach(16) to evaluate the system reliability indices. The efficiency of the approach is illustrated by considering practical system examples.

The failures of individual power system components may have quite complicated effects on the total system. The models considering only one system effect of a component failure, illustrated in the M.Sc. thesis[8], may provide very optimistic estimates of system reliability performance. This thesis models the component failures according to their system effects for more accurate reliability predictions. Two modes of component failure are considered, one resulting in the outage of other healthy components, called the active failure and the second resulting in the outage of only the component itself, called the passive failure. The manual solution of these models becomes quite labourious and unmanageable as the number of components and the system complexity increases. A computer program for the evaluation of load point reliability indices is described in this thesis. The program performs a failure modes and effects analysis (FMEA) and provides a concise and orderly description of various combinations of events within the system that could result in an interruption. The application of the program is illustrated by considering substation and switching station configurations.

It has been noted in references 17 and 29 that a major cause of double contingency outages is the occurrence of a component sustained outage during the period when another component is out for maintenance. Maintenance on components is performed to reduce their sustained outage rates. If the maintenance outage rate of a component is reduced, in order to decrease the probability of occurrence of double contingency of the above kind, an increase in component sustained outage rate may result. This thesis investigates the possibility of choosing some compromise between component maintenance rates and failure rates so that the overall system failure rate is reduced. This analysis requires the development of some functional relations between component failure and maintenance rates. Considerable improvement in reliability performance can be obtained by proper co-ordination of component maintenance. This thesis evaluates the reliability benefits associated with different policies of co-ordinating component maintenance.

The evaluation of interruptions due to component overload outages have always resulted in considerable amount of computational effort and time[36]. This thesis illustrates how this problem can be alleviated by using the cut set approach. Assuming constant component capabilities, the outage frequency and duration indices are calculated by using a two state load model[8]. This approach is extended for the evaluation of outage indices in systems involving many load points. The results obtained by this method are compared with those calculated by using techniques involving Markov analysis and load flow studies. A close proximity in the results is observed. Two additional measures of interrupted load and energy are introduced to estimate the severity of overloads.

There has been very little material available regarding the costs of supply interruptions incurred by electricity consumers. Some estimates of these costs have now been published[38,40] for different types of consumers. This thesis illustrates the application of these costs in the evaluation of economically justified investments in the system. The savings in costs of supply interruptions obtained by the use of spare transformers, standby units, additional facilities etc. can be compared with the investments in these facilities for a cost-benefit analysis. These costs can also be utilized in comparing the reliabilities of various systems on a consistent basis.

In conclusion, this thesis has presented several different aspects of the total power system reliability problem. The application of the models and techniques developed is illustrated by considering practical system examples. The concepts presented are quite general and can be applied to all parts of transmission and distribution schemes.

2. EVALUATION OF RELIABILITY INDICES USING TWO STATE COMPONENT MODELS

2.1 Introduction

Predicting the reliability performance of a system generally begins with the postulation of mathematical models of the components constituting the system. The selection of the model and the mathematical tools becomes a matter of compromise between the desired accuracy of the results and the effort required to obtain these results. A very important factor to be considered in establishing the goals for desired accuracy is the quality of available data. In transmission and distribution systems, the quality of data available does not justify the application of very exact and sophisticated models that require extensive effort and computer time. The model selected should, however, adequately reflect the effect of all those factors that actually influence the system reliability.

The Markov approach[5,6] is considered to be the most accurate way to model the performance of power system components provided the necessary distributional assumptions are valid. The application of this technique, however, becomes quite cumbersome as the number of components in the system increases. Considering a system of n two state components, there are 2^n possible system states. The number of states and the associated complexity increases rapidly if environment conditions and maintenance requirements are to be included in the reliability predictions. The application of this technique is therefore limited by the computer storage and time requirements and the rounding errors incurred in the solution. Another method of modelling is to use a Monte Carlo simulation[5,7] technique. This approach requires a minimum of assumptions for system reliability predictions and it is believed that a simulation method gives a fairly good estimate of true performance. This technique, however, requires large amounts of computer time and cannot be efficiently applied in relatively large practical systems.

In order to overcome the problems associated with the above two techniques, a set of simple equations was developed in reference 3 to evaluate the frequency and duration of outages at various load points within the system. It was clearly illustrated that the complete statistical independence between component sustained outages may not be a realistic representation and in certain cases can lead to low estimates of system reliability. A two state weather model was proposed [3] to model the performance of components such as overhead transmission lines exposed to changing environments. According to this model, each component in the system is assigned two failure rate values; one corresponding to normal weather periods and the other corresponding to adverse weather periods. It was stated in reference 3 that the reliability indices given by the developed equations compare closely with those obtained by a Markov approach. The actual comparison of the indices obtained by the approximate technique[3] and the Markov technique was made in a 1967 publication[6] and it was shown that the two methods do not give consistent results. A recent set of papers[9,10,11] developed a modified version of the approximate technique[3] and the predicted results compare very well with those obtained by the Markov approach. Two sets of equations were developed which model the occurrence or nonoccurrence of repairs during adverse weather periods.

This chapter illustrates a sequential and straightforward method for the calculation of reliability indices. The simple equations presented, when used in conjunction with a failure modes and effects analysis approach, provide a very efficient method of performing the reliability studies. The concepts involved in the formulation of equations are described in detail in reference 8.

2.2 Component Failure Categories[8]

The different failure categories of a component as considered in this chapter are shown in Figure 2.1. The definitions of various failure terms as accepted by the Institution of Electrical and Electronics Engineers (IEEE) and the Canadian Electrical Association (CEA) are given in Appendix A.1. The permanent or sustained outage of a component requires it to be taken out of service for a period of time during which it is repaired. The actual outage time experienced at the load point may be the time required to switch in the alternate facilities. If a component fault

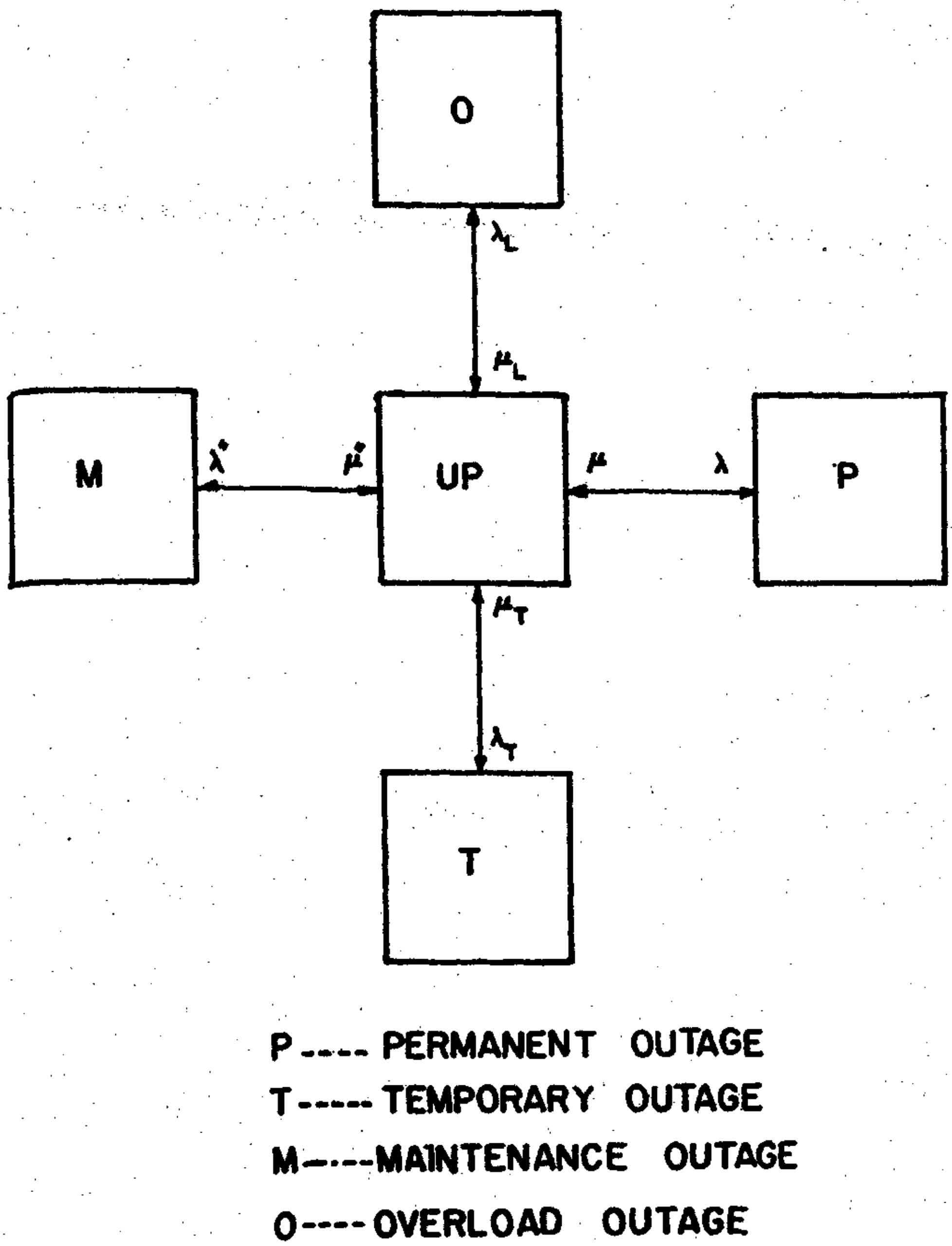


Figure 2.1 Distinct Failure Categories of a Component

If a component fault
is cleared by a reclosing operation of a circuit breaker or by an automatic switching operation, a temporary outage is said to have occurred. The duration associated with such component outages is generally of the order of a few minutes. Components are also taken out of service for preventive inspection and maintenance. During the periods when a component is removed from service for preventive action, it cannot perform its intended function. This can, therefore, be considered for the purposes of reliability analysis as another type of component failure. The final category of component failure considered in this chapter is the overload outage of a component. Under certain outage and system conditions, components may be called upon to carry loads which exceed their capability. This can result in outage of the component if the overcurrent relays trip the circuit breakers protecting the component. In an actual system, depending upon the amount of overload and the system philosophy, components may be called upon to carry the overload or be removed from service to prevent loss of life or permanent damage.

Component outages, depending upon the system configuration, may or may not cause service interruptions. The following combinations of the above component failure categories can cause temporary or sustained interruptions to the system load points.

(i) Sustained interruptions -

(a) Permanent outages of components.

(b) Overlapping permanent outages of components.

(c) Maintenance outages of components.

(d) Permanent outages of components overlapping maintenance outage periods of other components.

(e) Permanent outage of components resulting in overload outages of other components.

(ii) Temporary interruptions -

(a) Temporary outages of components.

(b) Temporary outages of components overlapping component permanent outages.

(c) Temporary outages of components overlapping maintenance outage periods of other components.

2.3 Reliability Indices

It is quite difficult to measure the reliability of transmission and distribution systems in terms of one composite reliability index. In regard to the quality of service being provided, there are many factors which influence customer satisfaction. It is believed that given satisfactory voltage, the average customer judges the quality of his service on the basis of composite reaction to any interruption. The reaction of a large group of customers is therefore dependent upon the following interruption attributes.

(i) Frequency (ii) Duration (iii) Magnitude of load interrupted (iv) Time of the day (v) Season of the year

Frequency and duration of outage are the most basic parameters. They can be greatly affected by careful system planning and design. In addition, by assigning economic penalties to frequency and duration of outages, a unified index of system performance can be obtained. This aspect is illustrated in Chapter 6.

In this thesis, frequency and duration of interruptions are considered as the basic measures of reliability. These indices are therefore determined for each designated system load point. The product of these two indices gives an additional useful index of total annual outage time. The three recommended indices are therefore as follows:

(i) Average number of service interruptions per year.

(ii) Average service restoration time.

(iii) Average total interruption time per year.

These indices also provide a basis, at least in distribution systems, for the comparison of predicted and actual system performance. This kind of facility is not available in the generating capacity reliability problem(12).

The load point oriented indices given above can be easily converted into customer and system type indices(14). The definitions of system and customer oriented indices are given in Appendix A.2.

2.4 Method of Analysis

2.4.1 The Technique -

The approach used in this thesis for predicting outage frequency and duration indices is based on determining the minimal cut sets* for the load point under consideration (15,16). A system is said to be connected if there exists a path between every point of component connection in the system. A cut set is a set of components which when removed from the system interrupts all connections between input and output. The removal of a minimal cut set results in separation of the system into exactly two connected subsystems; one containing all the input sources and the other containing the load point under consideration. This, in fact, implies that minimal cut sets are those for which a subset cannot be another cut set. If there are n points of component connection (including the source and load points) in the system, there are (n-1) minimal cut sets for a series system of components and 2^{n-2} if there is a component between every pair of component connection points. Therefore, depending on the system configuration, the number of minimal cuts varies from (n-1) to 2^{n-2}.

The cut set approach essentially makes a series parallel representation of complex system configurations. In fact, it is a mechanization of the contingency method long known by power system designers. The equations for simple series parallel systems can be used to compute the reliability indices. Some approximations are introduced by cut set considerations. This is discussed in Appendix B. The error introduced, however, is insignificant because of the very high reliability normally associated with power system components.

* See Appendix F

2.4.2 Assumptions

The various assumptions involved in the use of the above technique and the formulation of the equations described in the next section are as follows:

(i) Component failure and repair events are independent of each other.

(ii) Component repair rates are much larger than their failure rates.

(iii) Components can be assigned two failure rate values, one corresponding to normal weather periods and the other corresponding to adverse weather periods.

(iv) The time distributions of normal and adverse weather periods and component up and down times have known mean values.

(v) The durations of normal weather periods are much larger than those of adverse weather periods.

(vi) The probability of two overlapping independent component temporary outages is considered negligible. The probability of component overload occurring during the small durations associated with temporary outages is neglected.

(vii) Preventive maintenance is started in normal weather and is not performed if:

  (a) there is some outage already existing in a related portion of the system.

  (b) the removal of the component results in interruption or the overload of another component in the system.

In the following section, simple equations are described to evaluate outage frequencies and durations for first, second, and third order cut sets. Equations for higher order cut sets, can also be written if required.
The concepts involved in the formulation of these equations are clearly described in references 8, 9 and 10. It was also shown in these references that the frequency and duration indices given by the equations compare reasonably well with those obtained by a theoretically accurate Markov approach.

2.4.3 Equations For Evaluation of Reliability Indices -

The various symbols used in the equations to be described are as follows:

λ_i = The normal weather permanent outage rate of component i.

λ'_i = The adverse weather permanent outage rate of component i.

λ''_i = The maintenance outage rate of component i.

r_i = The expected repair time for component i.

r''_i = The expected maintenance time for component i.

N = The average duration of a normal weather period.

S = The average duration of an adverse weather period.

λ_{iT} = The normal weather temporary outage rate of component i.

λ'_{iT} = The adverse weather temporary outage rate of component i.

λ_L = The rate of occurrence of load level >L.

r_L = The average duration of load level >L.

$\lambda_{av,i}$ = The average annual failure rate of component i.

λ_{i-j} = The overlapping outage rate of components i and j due to permanent outages.

r_{i-j} = The overlapping outage duration of components i and j due to permanent outages.

T_{si} = The switching time for component i.

λ_{SL} = The contribution to the load point outage rate due to component permanent outages.

λ''_{ML} = The contribution to the load point outage rate due to component permanent outages overlapping component maintenance outages.

λ_{tL} = The contribution to the load point outage rate due to component temporary outages overlapping component maintenance or permanent outages.

λ_{oL} = The contribution to the load point outage rate due to component overload outages overlapping component permanent outages.

r_{SL} = The load point average outage duration due to component permanent or overlapping permanent outages.

r''_{ML} = The load point average outage duration due to component permanent outages overlapping component maintenance outages.

r_{oL} = The load point average outage duration due to component overload outages.

$\ell(t)$ = The system load at time t.

L = The capability of the remaining components in the system after a permanent outage.

Equations for reliability indices due to component permanent outages.

The equations are described for occurrence and non-occurrence of repairs during adverse weather.

(a) Repair during adverse weather.

First order cut set

Let i be the component contained in the cut set, then

$$\lambda_{SL} = \lambda_{av,i}$$

$$r_{SL} = r_i$$

Second order cut set

Let the components contained in the cut set be i and j. If no normal and adverse weather aspect is considered, then

$$\lambda_{SL} = \lambda_{av,i}\,\lambda_{av,j}\,(r_i+r_j)$$

$$r_{SL} = \frac{r_i r_j}{r_i+r_j}$$

If normal and adverse weather aspect is included, then

$$\lambda_{SL} = \frac{N}{N+S}\left[\lambda_i\lambda_j(r_i+r_j)+\frac{S}{N}\left(\lambda_i\lambda_j'\frac{r_i^2}{S+r_i}+\lambda_i'\lambda_j\frac{r_j^2}{S+r_j}\right)\right] + \frac{S}{N+S}\left[\lambda_i'\lambda_j r_i+\lambda_j'\lambda_i r_j+\lambda_i'\lambda_j' S\left(\frac{r_i}{S+r_i}+\frac{r_j}{S+r_j}\right)\right]$$

$$r_{SL} = \frac{r_i r_j}{r_i+r_j}$$

Third order cut set

Let the components contained in the cut set be i, j and k.

If no normal and adverse weather aspect is considered, then

$$\lambda_{SL} = \lambda_{av,i}\,\lambda_{av,j}\,\lambda_{av,k}\,(r_i r_j + r_j r_k + r_k r_i)$$

$$r_{SL} = \frac{r_i r_j r_k}{r_i r_j + r_j r_k + r_k r_i}$$

If normal and adverse weather aspect is included, then

$$\lambda_{SL} = A + B$$

where

$$A = \frac{N}{N+S}\Big[\lambda_i \{\lambda_j \lambda_k r_i^2 \left(\frac{r_j}{r_i+r_j} + \frac{r_k}{r_i+r_k}\right) + \frac{S\ r_i^3}{S+r_i} \left(\lambda_j' \lambda_k \frac{r_j}{Nr_i+Nr_j+r_i r_j} + \lambda_j \lambda_k' \frac{r_k}{Nr_i+Nr_k+r_i r_k}\right)\} + \text{Similar terms for components j and k}\Big]$$

$$+ \frac{S}{N+S}\Big[\lambda_i' \{\lambda_j \lambda_k \frac{N^2 r_i^2}{N+r_i} \left(\frac{r_j}{Nr_i+Nr_j+r_i r_j} + \frac{r_k}{Nr_i+Nr_k+r_i r_k}\right)$$

$$+ \frac{NSr_i^2}{S+r_i}\left(\lambda_j' \lambda_k \frac{r_j}{Nr_i+Nr_j+r_i r_j} + \lambda_j \lambda_k' \frac{r_k}{Nr_i+Nr_k+r_i r_k}\right)$$

$$+ \text{Similar terms for components j and k}\Big]$$

and

$$B = \frac{N}{N+S}\Big[\lambda_i \{\lambda_j' \lambda_k' \frac{S^2 r_i^3}{(S+r_i)N} \left(\frac{r_j}{Sr_i+Sr_j+r_i r_j} + \frac{r_k}{Sr_i+Sr_k+r_i r_k}\right)$$

$$+ \frac{r_i^3 S}{N}\left(\frac{r_j^2}{(r_i+r_j)(Sr_i+Sr_j+r_i r_j)} + \frac{r_k^2}{(r_i+r_k)(Sr_i+Sr_k+r_i r_k)}\right)\}$$

$$+ \text{Similar terms for components j and k}\Big]$$

$$+ \frac{S}{N+S}\Big[\lambda_i' \{\lambda_j' \lambda_k' \frac{S^2 r_i^2}{S+r_i} \left(\frac{r_j}{Sr_i+Sr_j+r_i r_j} + \frac{r_k}{Sr_i+Sr_k+r_i r_k}\right)$$

$$+ \frac{r_i^3 NS}{N+r_i}\left(\frac{r_j^2}{(Sr_i+Sr_j+r_i r_j)(Nr_i+Nr_j+r_i r_j)}\right.$$

$$\left. + \frac{r_k^2}{(Sr_i+Sr_k+r_i r_k)(Nr_i+Nr_k+r_i r_k)}\right)\}$$

$$+ \text{Similar terms for components j and k}\Big]$$

$$r_{SL} = \frac{r_i r_j r_k}{r_i r_j + r_j r_k + r_k r_i}$$

(b) No repair during adverse weather.

First order cut set

Let the component contained in the cut set be i, then

$$\lambda_{SL} = \lambda_i \frac{N}{N+S} + \lambda_i' \frac{S}{N+S} = \lambda_{av,i}$$

$$r_{SL} = \frac{\lambda_i N r_i + \lambda_i' S \ (S+r_i)}{\lambda_i N + \lambda_i' S}$$

<u>Second order cut set</u>

Let the components contained in the cut set be i and j, then

$$\lambda_{SL} = A + B$$

where

$$A = \frac{N}{N+S} \left[\lambda_i \lambda_j (r_i + r_j) + \frac{S}{N} (\lambda_i' \lambda_j r_i + \lambda_i \lambda_j' r_j)\right]$$

$$B = \frac{S}{N+S} \left[2\lambda_i' \lambda_j' S + \lambda_i \lambda_j' r_i + \lambda_i' \lambda_j r_j\right]$$

$$r_{SL} = \frac{A}{A+B} \left[\frac{r_i r_j}{r_i + r_j}\right] + \frac{B}{A+B} \left[\frac{r_i r_j}{r_i + r_j} + S\right]$$

<u>Third order cut set</u>

Let the components contained in the cut set be i, j and k, then

$$\lambda_{SL} = A + B$$

where

$$\begin{aligned} A = \frac{N}{N+S} \Big[\lambda_i \ & \{\lambda_j \lambda_k r_i^2 \ (\frac{r_j}{r_i + r_j} + \frac{r_k}{r_i + r_j}) \\ & + \frac{S}{N} r_i^2 \ (\lambda_j' \lambda_k \frac{r_j}{r_i + r_j} + \lambda_j \lambda_k' \frac{r_k}{r_i + r_k})\} \\ & + \text{Similar terms for components j and k} \Big] \\ & + \frac{S}{N+S} \Big[\lambda_i' \ \{\lambda_j \lambda_k r_i^2 \ (\frac{r_j}{r_i + r_j} + \frac{r_k}{r_i + r_k}) \\ & + S r_i \ (\lambda_j' \lambda_k \frac{r_j}{r_i + r_j} + \lambda_j \lambda_k' \frac{r_k}{r_i + r_k})\} \\ & + \text{Similar terms for components j and k} \Big] \end{aligned}$$

$$B = \frac{N}{N+S}\Big[\lambda_i\{2\lambda_j'\lambda_k'\frac{S}{N}^2\ r_i+\frac{S}{N}r_i^2\ (\lambda_j\lambda_k'\frac{r_j}{r_i+r_j}+\lambda_j'\lambda_k\ \frac{r_k}{r_i+r_k})\}$$

$$+ \text{ Similar terms for components j and k}\Big]$$

$$+ \frac{S}{N+S}\Big[\lambda_i'\{2\lambda_j'\lambda_k'S^2 + \frac{S}{N}r_i^2(\lambda_j\lambda_k'\frac{r_j}{r_i+r_j} + \lambda_j'\lambda_k\ \frac{r_k}{r_i+r_k})\}$$

$$+ \text{ Similar terms for components j and k}\Big]$$

$$r_{SL} = \frac{A}{A+B}\Big[\frac{r_ir_jr_k}{r_ir_j + r_jr_k + r_kr_i}\Big] + \frac{B}{A+B}\Big[\frac{r_ir_jr_k}{r_ir_j+r_jr_k+r_kr_i} + S\Big]$$

If the service can be restored by switching out the failed components or switching in alternate facilities, then $r_{SL} = T_s$ in the previously noted equations.

The effect of varying component and weather parameters on system reliability indices by the use of above equations has been illustrated in references 8 and 9.

<u>Equations for reliability indices due to component permanent outages overlapping maintenance periods</u>.

Two sets of equations are given below considering whether or not the weather can change during the maintenance period.

(a) Weather cannot change during the maintenance period.

<u>Second order cut set</u>

Let the components contained in the cut set be i and j, then

$$\lambda''_{ML} = \lambda''_i\lambda_jr''_i + \lambda''_j\lambda_ir''_j$$

$$r''_{ML} = \frac{\lambda''_i\lambda_jr_i^{2''}r_j}{\lambda''_{ML}(r''_i+r_j)} + \frac{\lambda''_j\lambda_ir_j^{''2}r_i}{\lambda''_{ML}(r_i+r''_j)}$$

If no normal and adverse weather aspect is considered, then the λ values in the above equations represent λ_{av}.

Third order cut set

Let the components contained in the cut set be i, j and k, then

$$\lambda''_{ML} = A + B + C$$

where

$$A = \lambda''_i \lambda_j \lambda_k r''^2_i \left(\frac{r_j}{r''_i + r_j} + \frac{r_k}{r''_i + r_k}\right)$$

$$B = \lambda''_j \lambda_i \lambda_k r''^2_j \left(\frac{r_i}{r''_j + r_i} + \frac{r_k}{r''_j + r_k}\right)$$

$$C = \lambda''_k \lambda_i \lambda_j r''^2_k \left(\frac{r_i}{r''_k + r_i} + \frac{r_j}{r''_k + r_j}\right)$$

$$r''_{ML} = \frac{A}{\lambda''_{ML}}\left[\frac{r''_i r_j r_k}{r''_i r_j + r''_i r_k + r_j r_k}\right] + \frac{B}{\lambda''_{ML}}\left[\frac{r_i r''_j r_k}{r_i r''_j + r''_j r_k + r_k r_i}\right]$$
$$+ \frac{C}{\lambda''_{ML}}\left[\frac{r_i r_j r''_k}{r_i r_j + r_j r''_k + r_i r''_k}\right]$$

If no normal and adverse weather aspect of failures is considered, then the λ values in the above equations represent λ_{av}.

(b) Weather can change during the maintenance period.

Two sets of equations considering whether or not the repair and maintenance started in normal weather is carried on in adverse weather, are given below.

(i) Repair and maintenance started in normal weather is carried on in adverse weather.

Second order cut set

Let the components contained in the cut set be i and j, then

$$\lambda''_{ML} = A + B$$

where

$$A = \lambda_i'' \lambda_j r_i'' + \lambda_i'' \lambda_j' \frac{r_i''^2}{N} \frac{S}{S+r_i''}$$

$$B = \lambda_j'' \lambda_i r_j'' + \lambda_j'' \lambda_i' \frac{r_j''^2}{N} \frac{S}{S+r_j''}$$

$$r_{ML}'' = \frac{A}{\lambda_{ML}''} \left[\frac{r_i'' r_j}{r_i''+r_j}\right] + \frac{B}{\lambda_{ML}''} \left[\frac{r_j'' r_i}{r_i+r_j''}\right]$$

<u>Third order cut set</u>

Let the components contained in the cut set be i, j and k, then

$$\lambda_{ML}'' = A + B + C$$

where

$$\begin{aligned} A = \lambda_i'' \Big[& \lambda_j \lambda_k r_i''^2 \left(\frac{r_j}{r_i''+r_j} + \frac{r_k}{r_i''+r_k}\right) \\ & + \frac{Sr_i^3}{N} \Big(\lambda_j \lambda_k' \frac{r_j^2}{(r_i''+r_j)(Sr_i''+Sr_j+r_i''r_j)} \\ & + \lambda_j' \lambda_k \frac{r_k^2}{(r_i''+r_k)(Sr_i''+Sr_k+r_i''r_k)} \Big) \\ & + \frac{Sr_i''^3}{S+r_i''} \left(\frac{\lambda_j' \lambda_k r_j}{Nr_i''+Nr_j+r_i''r_j} + \frac{\lambda_k' \lambda_j r_k}{Nr_i''+Nr_k+r_i''r_k}\right) \\ & + \lambda_j' \lambda_k' \frac{S^2 r_i''^3}{N(S+r_i'')} \left(\frac{r_j}{Sr_i''+Sr_j+r_i''r_j} + \frac{r_k}{Sr_i''+Sr_k+r_i''r_k}\right) \Big] \end{aligned}$$

B and C are similar to A but for components j and k respectively.

$$\begin{aligned} r_{ML}'' = & \frac{A}{\lambda_{ML}''} \left[\frac{r_i'' r_j r_k}{r_i''r_j+r_i''r_k+r_j r_k}\right] + \frac{B}{\lambda_{ML}''} \left[\frac{r_i r_j'' r_k}{r_i r_j''+r_j'' r_k+r_i r_k}\right] \\ & + \frac{C}{\lambda_{ML}''} \left[\frac{r_i r_j r_k''}{r_i r_j+r_j r_k''+r_k'' r_i}\right] \end{aligned}$$

(ii) Repair and maintenance started in normal weather is discontinued in adverse weather.

Second order cut set

Let the components contained in the cut set be i and j, then

$$\lambda''_{ML} = A + B + C + D$$

where

$$A = \lambda''_i \lambda_j r''_i \qquad B = \lambda''_i \lambda'_j \frac{S}{N} r''_i$$

$$C = \lambda''_j \lambda_i r''_j \qquad D = \lambda''_j \lambda_i \frac{S}{N} r''_j$$

$$r''_{ML} = \frac{A}{\lambda''_{ML}} \left[\frac{r''_i r_j}{r''_i + r_j}\right] + \frac{B}{\lambda''_{ML}} \left[\frac{r''_i r_j}{r''_i + r_j} + S\right]$$

$$+ \frac{C}{\lambda''_{ML}} \left[\frac{r_i r''_j}{r_i + r''_j}\right] + \frac{D}{\lambda''_{ML}} \left[\frac{r_i r''_j}{r_i + r''_j} + S\right]$$

Third order cut set

Let the components contained in the cut set be i, j and k, then

$$\lambda''_{ML} = A + B + C + D + E + F$$

$$A = \lambda''_i \left[\lambda_j \lambda_k r''^2_i \left(\frac{r_j}{r''_i + r_j} + \frac{r_k}{r''_i + r_k}\right)\right.$$

$$\left. + \frac{r''^2_i S}{N} \left(\lambda'_j \lambda_k \frac{r_j}{r''_i + r_j} + \lambda_j \lambda'_k \frac{r_k}{r_k + r''_i}\right)\right]$$

$$B = \lambda''_i \left[\frac{r''^2_i S}{N} \left(\lambda_j \lambda'_k \frac{r_j}{r''_i + r_j} + \lambda'_j \lambda_k \frac{r_k}{r''_i + r_k}\right) + 2\lambda'_j \lambda'_k \frac{S^2}{N} r''_i\right]$$

C and E are similar to A but for components j and k respectively.

D and E are similar to B but for components j and k respectively.

$$r''_{ML} = \left[\left\{\frac{r_i R}{r''_i + R}\right\} + \text{Similar terms for components j and k}\right]$$

where

$$R = \frac{A}{\lambda''_{ML}}\left[\frac{r_i r_j r_k}{r''_i r_j + r''_i r_k + r_j r_k}\right] + \frac{B}{\lambda''_{ML}}\left[\frac{r_i r_j r_k}{r''_i r_j + r''_i r_k + r_j r_k} + S\right]$$

In the above cases if service can be restored by switching out the failed components or switching in alternate facilities, then $r''_{ML} = T_s$.

In references 8 and 10 it was illustrated that the maintenance contribution to the system outage rate decreases as the component failures during adverse weather periods increase. This is true if it is assumed that component maintenance is not allowed to extend into the adverse weather periods. If, however, the weather can change during maintenance periods, the maintenance contribution to system outage rate does not change significantly with increasing number of component failures during adverse weather. This is illustrated in Figure 2.2 for a second order cut set for different component maintenance parameters.

<u>Equations for reliability indices due to component temporary outages.</u>

Two sets of equations, based on whether the component temporary outages overlap permanent or maintenance outage periods, are given below.

(a) Component temporary outages overlapping component permanent outages.

<u>First order cut set</u>

Let the component contained in the cut set be i, then

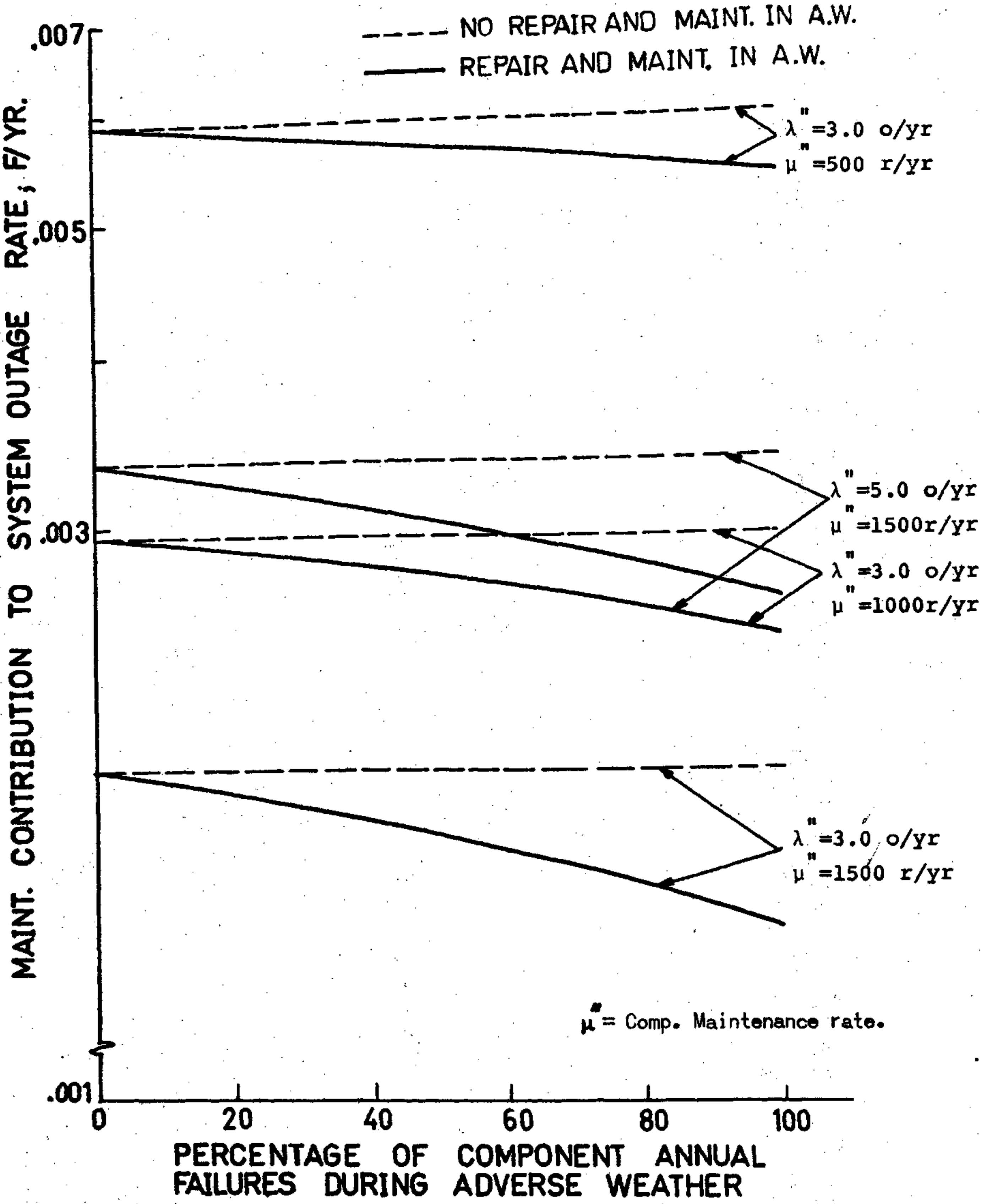


Figure 2.2 Contribution To System Outage Rate Due to Component Maintenance as a Function of Component Failures During Adverse Weather.

$$\lambda_{tL} = \lambda_{iT}$$

<u>Second order cut set</u>

Let the components contained in the cut set be i and j, then

$$\lambda_{tL} = \lambda_{av,i}\lambda_{jT}r_i + \lambda_{av,j}\lambda_{iT}r_j$$

<u>Third order cut set</u>

$$\lambda_{tL} = \lambda_{i-j}\lambda_{kT}r_{i-j} + \lambda_{i-k}\lambda_{jT}r_{i-k} + \lambda_{j-k}\lambda_{iT}r_{j-k}$$

These equations are applicable if component temporary outages are not separated into normal and adverse weather failures and the λ_{iT} values represent the component overall annual temporary outage rate.

If it is necessary to classify temporary outages into normal and adverse weather failures, the following equations apply.

<u>First order cut set</u>

Let the component contained in the cut set be i, then

$$\lambda_{tL} = \frac{N}{N+S}\lambda_{iT} + \frac{S}{N+S}\lambda'_{iT}$$

<u>Second order cut set</u>

Let the components contained in the cut set be i and j. If no repair is performed during adverse weather, then

$$\lambda_{tL} = \frac{N}{N+S}\left[\lambda_i\lambda_{jT}r_i + \lambda_j\lambda_{iT}r_j + \frac{S}{N}(\lambda'_i\lambda_{jT}r_i+\lambda'_j\lambda_{iT}r_j)\right]$$

$$+ \frac{S}{N+S}\left[\lambda_i\lambda'_{jT}r_i + \lambda_j\lambda'_{iT}r_j + \lambda'_i\lambda'_{jT}S + \lambda'_j\lambda'_{iT}S\right]$$

If repairs are carried on in adverse weather,

$$\lambda_{tL} = \frac{N}{N+S}\left[\lambda_i\lambda_{jT}r_i + \lambda_j\lambda_{iT}r_j + \frac{S}{N}\left(\lambda_i'\lambda_{jT}\frac{Nr_i}{N+r_i} + \lambda_j'\lambda_{iT}\frac{Nr_j}{N+r_j}\right)\right]$$

$$+ \frac{S}{N+S}\left[\lambda_i\lambda_{jT}'\frac{Sr_i}{S+r_i} + \lambda_j\lambda_{iT}'\frac{Sr_j}{S+r_j} + \lambda_i'\lambda_{jT}'\frac{Sr_i}{S+r_i}\right.$$

$$\left. + \lambda_j'\lambda_{iT}'\frac{Sr_j}{S+r_j}\right]$$

For a third order cut set similar equations can be written.

(b) Component temporary outages overlapping component maintenance periods.

Two sets of equations are possible depending upon whether the weather can or cannot change during maintenance periods.

(i) Weather cannot change during maintenance periods.

<u>Second order cut set</u>

Let the components contained in the cut set be i and j, then

$$\lambda_{tL} = \lambda_i''\lambda_{jT}r_i'' + \lambda_j''\lambda_{iT}r_j''$$

<u>Third order cut set</u>

Let the components contained in the cut set be i, j and k, then

$$\lambda_{tL} = \lambda_i''\left[\lambda_j\lambda_{kT}\frac{r_i''^2 r_j}{r_i''+r_j} + \lambda_{jT}\lambda_k\frac{r_i''^2 r_k}{r_i''+r_k}\right] + \lambda_j''\left[\lambda_i\lambda_{kT}\frac{r_j''^2 r_i}{r_j''+r_i}\right.$$

$$\left. + \lambda_k\lambda_{iT}\frac{r_j''^2 r_k}{r_j''+r_k}\right] + \lambda_k''\left[\lambda_i\lambda_{jT}\frac{r_i r_k''^2}{r_i+r_k''} + \lambda_{iT}\lambda_j\frac{r_j r_k''^2}{r_j+r_k''}\right]$$

If component temporary outages are separated into normal and adverse weather failures, then the λ_{iT} values in the above equations represent the component normal weather outage rate.

(ii) Weather can change during the maintenance period.

Second order cut set

Let the components contained in the cut set be i and j. If maintenance started in normal weather is continued in adverse weather, then

$$\lambda_{tL} = \lambda_i'' \left[\lambda_{jT} r_i'' + \lambda_{jT}' \frac{S r_i''^2}{N(S+r_i'')} \right] + \lambda_j'' \left[\lambda_{iT} r_j'' + \lambda_{iT}' \frac{S r_j''^2}{N(S+r_j'')} \right]$$

If maintenance is discontinued in adverse weather, then

$$\lambda_{tL} = \lambda_i'' \left[\lambda_{jT} r_i'' + \lambda_{jT}' \frac{S r_i''}{N} \right] + \lambda_j'' \left[\lambda_{iT} r_j'' + \lambda_{iT}' \frac{S r_j''}{N} \right]$$

For a third order cut set, similar equations can be written.

Equations for reliability indices due to component overload outages.

Second order cut set

Let the components i and j contained in the cut set are both liable to overload. Assuming that the system load is supplied through the components present in the cut set,

$$\lambda_{oL} = A + B$$

where

$$A = \lambda_L \lambda_j r_j (1 - Pr(\ell(t) > L_i)) + \lambda_j Pr(\ell(t) > L_i)$$

$$B = \lambda_L \lambda_i r_i (1 - Pr(\ell(t) > L_j)) + \lambda_i Pr(\ell(t) > L_j)$$

$$r_{oL} = \frac{A}{A+B} \left[\frac{r_j r_L}{r_j + r_L} \right] + \frac{B}{A+B} \left[\frac{r_i r_L}{r_i + r_L} \right]$$

Third order cut set

The components i, j and k contained in the cut set are all liable to overload. Assuming that the system load is supplied through all the components present in the cut set

$$\lambda_{oL} = A + B + C$$

where

$$A = \lambda_L(1-Pr(\ell(t)>L_i))\ (\lambda_{j-k}r_{j-k}) + \lambda_{j-k}Pr(\ell(t)>L_i)$$

$$B = \lambda_L(1-Pr(\ell(t)>L_j))\ (\lambda_{i-k}r_{i-k}) + \lambda_{i-k}Pr(\ell(t)>L_j)$$

$$C = \lambda_L(1-Pr(\ell(t)>L_k))\ (\lambda_{i-j}r_{i-j}) + \lambda_{i-j}Pr(\ell(t)>L_k)$$

$$r_{oL} = \frac{A}{\lambda_{oL}}\left[\frac{r_{j-k}r_{Li}}{r_{j-k}+r_{Li}}\right] + \frac{B}{\lambda_{oL}}\left[\frac{r_{i-k}r_{Lj}}{r_{i-k}+r_{Lj}}\right] + \frac{C}{\lambda_{oL}}\left[\frac{r_{i-j}r_{Lk}}{r_{i-j}+r_{Lk}}\right]$$

In these equations, it is assumed that component overload can occur only if two of the components in the cut set are on permanent outage. If, however, remaining components can suffer overload outages because of a component permanent outage, the above equations can be easily modified. Overload analysis is considered in Chapter 5 of this thesis.

2.4.4 Sequential Analysis

A very simple and straightforward method is used to perform the reliability studies illustrated in this section. System components are first identified and the component reliability parameters, such as outage rates and durations, capability etc. and system parameters such as average durations of weather periods, load cycles etc. are then supplied.

The analysis starts with the determination of minimal cut sets for the load point under consideration. The equations described in the previous section can be permanently stored in the computer system. Appropriate equations, according to the order of cut set, conditions of repair, maintenance, weather etc., are called in to evaluate the contributions of the cut set under consideration. For example, in a second order cut set, all the appropriate equations are called in to evaluate the reliability indices due to component permanent, temporary, maintenance and overload outage categories. Once all the possible modes of interruption at the designated load point due to the cut set under consideration are exhausted, the outage calculations proceed to the next cut set. This method proceeds sequentially until the contributions to the load point reliability indices due to all cut sets have been evaluated.

Contributions from different cut sets to permanent and temporary interruptions are finally added to evaluate the overall permanent and temporary outage indices at the load point under consideration. The relative contribution of each cut set to the reliability indices provides an effective quantitative tool in assessing the components and their parameters which make major contributions to system unreliability.

It is important to appreciate that the simple equations involve only basic mathematical operations. The execution of these operations in the computer is very fast. In addition, these equations are fairly general in their formulation and can be extended to include other conditions which might be encountered in practical transmission and distribution systems. Another advantage of the method is that only the failure related events are computed in reliability calculations and no time is therefore wasted in calculating the frequencies and durations associated with successful system states.

2.5 System Studies

Three simple system studies, using the method of analysis presented in the previous section, are considered. The first example pertains to the evaluation of reliability indices at various load points of the Saskatchewan Power Corporation underground distribution system in the Regina downtown area shown in Figure 2.3[11]. The following component reliability parameters were assumed for this study.

Cable failure rate including joints and terminations = 0.002 f/100'/yr ✓ 0.0084 f/mile

Average time required to repair cable failures = ~~6.0~~ 40 hours.

Average ~~switching~~ sectionalizing time = 1.5 hours. too high

Distribution transformer failure rate = 0.012 f/yr. too high

Average time required to repair a distribution transformer = 5.0 hours.

In this particular example, no maintenance or temporary outages are considered. The system can be considered to be made up of two parts, one on each side of the normally open connections. The reliability indices obtained at different load points by performing a manual by failure analysis are given in Table 2.1.

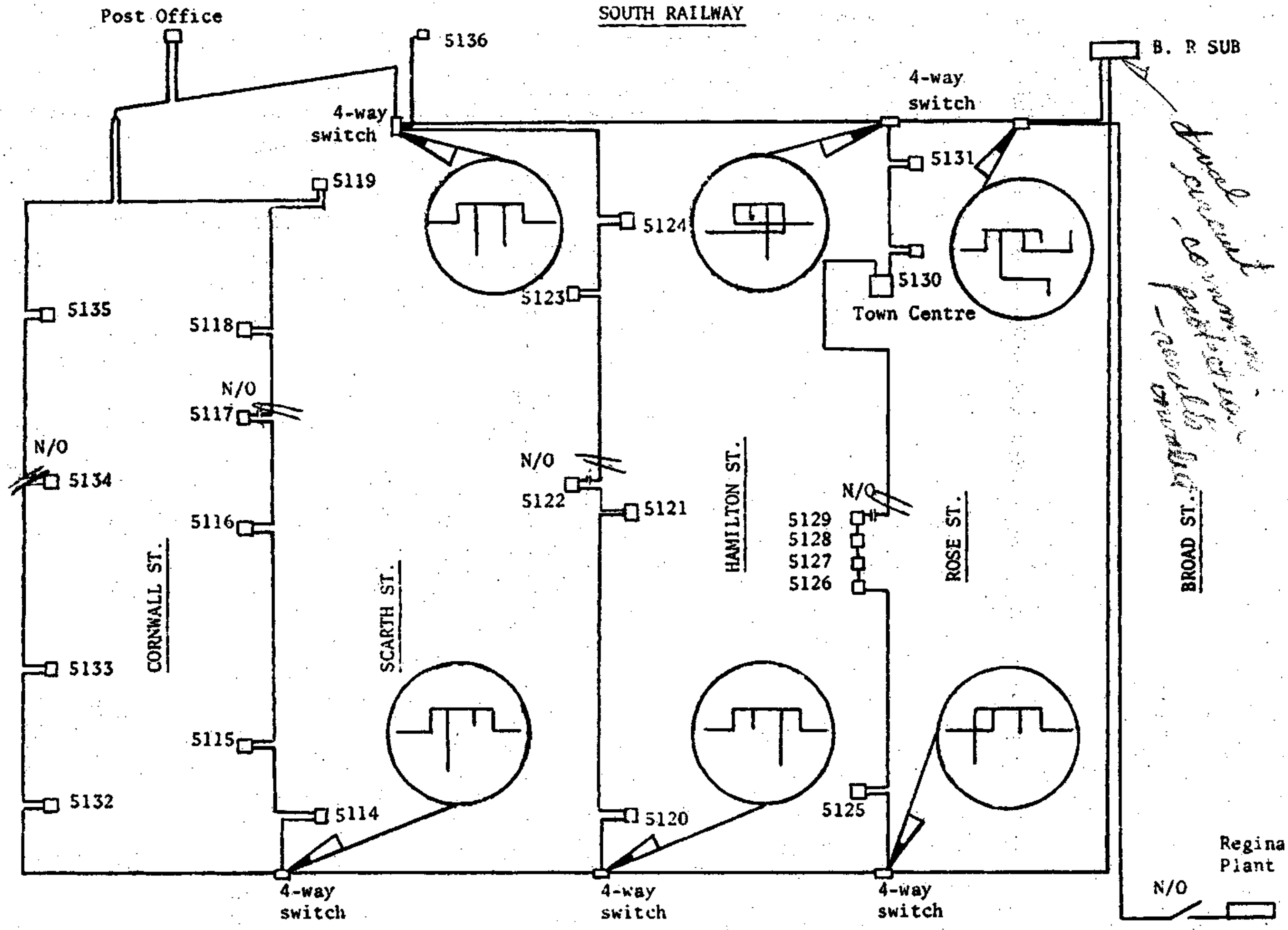


Figure 2.3 Regina Downtown Underground Distribution ~~System~~ Circuit

TABLE 2.1

RELIABILITY INDICES AT VARIOUS LOAD POINTS OF REGINA DOWNTOWN UNDERGROUND DISTRIBUTION SYSTEM

Case	Load Points	Failure Rate f/yr	Average Outage Duration, Hrs.	Total Outage Time Hrs./Yr.
Unfused Tappings	Upper half section	0.109	1.88	0.2055
	Lower half section	0.117	1.85	0.2175
	5136	0.109	2.06	0.2245
Fused Tappings	5130, 5131, Midtown Centre	0.092	1.95	0.1800
	5123, 5124	0.093	1.95	0.1810
	5118, 5119, 5135, Post Office	0.076	2.05	0.1560
	5136	0.076	2.17	0.1650
	5125, 5126, 5127, 5128, 5129	0.087	1.98	0.1725
	5120, 5121, 5122	0.092	1.95	0.1800
	5114, 5115, 5116, 5117	0.094	1.94	0.1830
	5132, 5133, 5134	0.078	2.04	0.1590

The second example considers a possible urban distribution system shown in Figure 2.4. The system is fed from three perfectly reliable sources of supply on the high voltage side. Three step down transformers then feed the distribution area. There are eight laterals in the system and each lateral is protected by its own fusing. In this case, loss of continuity between the source and the load points is considered to be the only mode of failure. The component and weather parameters used in this study are given in Table 2.2[8]. Table 2.3 gives the complete reliability analysis for load point 2. The events that cause load point interruptions are listed and their contributions to outage indices are also indicated. A summary of the reliability indices obtained at load points 3, 4, 5 and 6 is given in Table 2.4.

The computational efficiency of the method is clearly indicated by the fact that the time required to obtain the results given in Tables 2.3 and 2.4 on the IBM 370/158 computer was only 9 seconds. (This value includes both the compilation and execution times.)

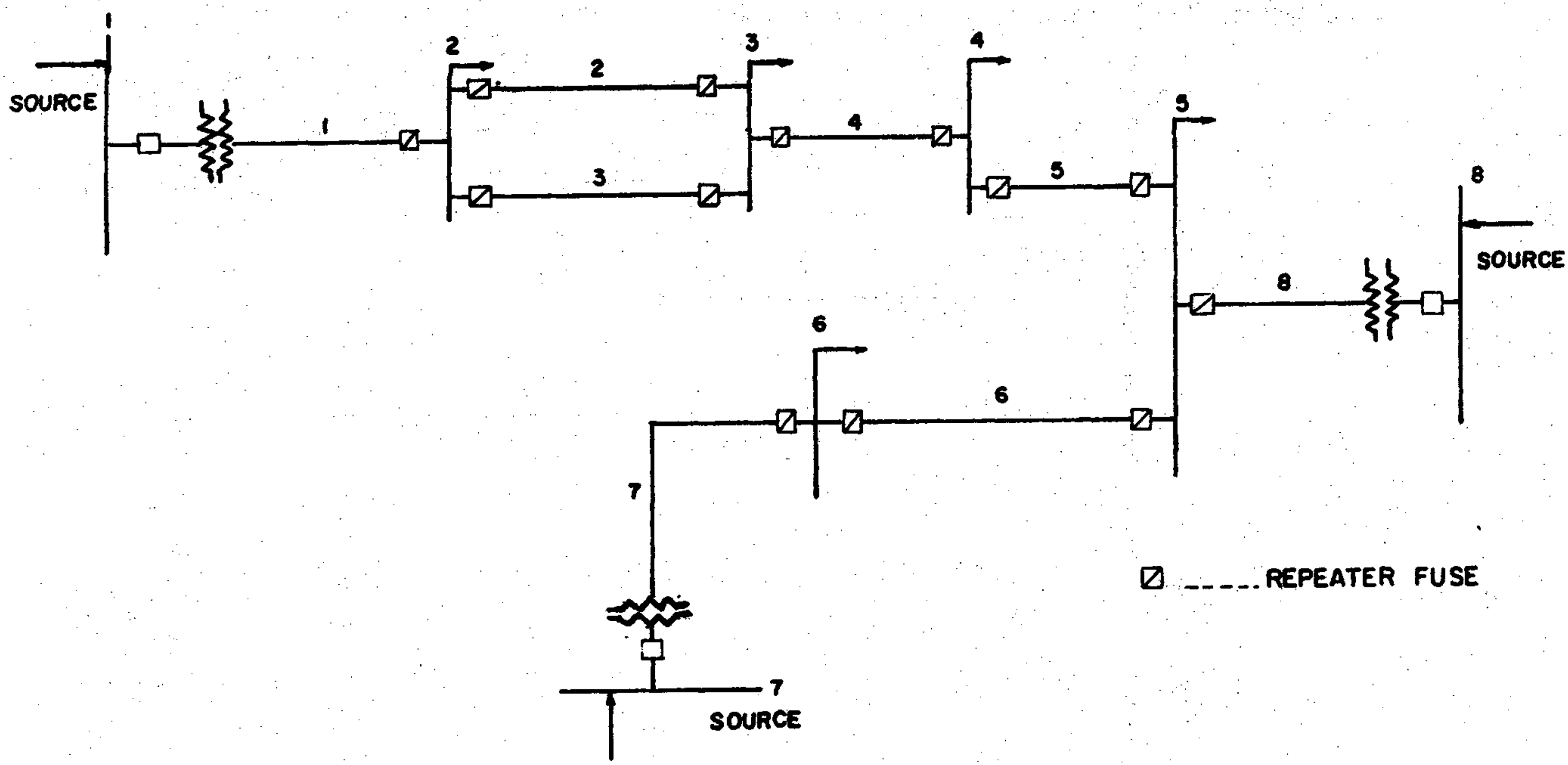


Figure 2.4 A Hypothetical Distribution Scheme

TABLE 2.2

COMPONENT PARAMETERS FOR THE RELIABILITY STUDY OF THE SYSTEM OF FIGURE 2.4

Component	Normal Weather Outage Rate f/yr.		Adverse Weather Outage Rate f/yr.		Outage Duration Hours	Maintenance Outage Rate o/yr.	Maintenance Outage Duration Hours
	Permanent	Temporary	Permanent	Temporary			
Transformer	0.02	---	0.02	---	62.0	1.0	10.0
Element #1	0.58	1.0	29.98	10.0	2.0	1.0	2.0
Element #2	0.50	2.0	25.0	20.0	8.0	3.0	8.0
Element #3	0.50	2.0	25.0	20.0	8.0	3.0	8.0
Element #4	1.0	2.0	50.0	20.0	12.0	1.0	6.0
Element #5	0.60	2.0	30.0	20.0	4.0	1.0	8.0
Element #6	0.30	1.0	15.0	10.0	6.0	1.0	8.0
Element #7	0.58	1.0	29.98	10.0	2.0	1.0	2.0
Element #8	0.58	1.0	29.98	10.0	2.0	1.0	2.0

Average duration of a normal weather period = 200.0 Hours.

Average duration of an adverse weather period = 1.50 Hours.

No repair during adverse weather periods.

Load points 1, 7 and 8 are 100% reliable.

TABLE 2.3

RELIABILITY ANALYSIS OF THE SYSTEM OF FIG. 2.4

Reliability Indices at Load Point 2

Contingency	Permanent Outages f/yr.	Temporary Outages f/yr.	Duration of Permanent Outages 10^{-3} Years
Permanent and temporary interruptions resulting from component permanent and temporary outages.			
Line sections 1 and 4 out.	0.0057200	0.0041600	0.469
Line sections 1 and 5 out.	0.0028600	0.0023300	0.372
Line sections 1, 2 and 3 out.	0.0000283	0.0000256	0.391
Line sections 1, 6 and 8 out.	0.0000195	0.0000078	0.336
Line sections 1, 7 and 8 out.	0.0000384	0.0000144	0.318

Permanent outage rate due to overlapping component permanent outages = 0.00867 f/yr.

Average outage duration due to overlapping component permanent outages = 3.818 Hours.

Temporary outage rate due to component temporary outages overlapping component permanent outages = 0.00653 f/yr.

Table 2.3 (cont'd)

Table 2.3 - RELIABILITY ANALYSIS OF THE SYSTEM OF FIG. 2.4 (cont'd)

Component temporary and permanent outages overlapping component maintenance outage	Permanent Outages f/yr.	Temporary Outages f/yr.	Duration of Permanent Outages 10^{-3} Years
Line section 1 maint., Line section 4 out.	0.0013600	0.0027370	0.456
Line section 4 maint., Line section 1 out.	0.0004100	0.0006844	0.273
Line section 1 maint., Line section 5 out.	0.0008200	0.0027370	0.273
Line section 5 maint., Line section 1 out.	0.0005480	0.0009130	0.304
Line section 1 maint., Line sections 2 & 3 out.	0.0000003	0.0000016	0.273
Line section 2 maint., Line sections 1 & 3 out.	0.0000006	0.0000016	0.228
Line section 3 maint., Line sections 1 & 2 out.	0.0000006	0.0000016	0.228
Line section 1 maint., Line sections 6 & 8 out.	0.0000002	0.0000004	0.195
Line section 6 maint., Line sections 1 & 8 out.	0.0000002	0.0000003	0.182
Line section 8 maint., Line sections 1 & 6 out.	0.0000002	0.0000004	0.195
Line section 1 maint., Line sections 7 & 8 out.	0.0000003	0.0000005	0.171
Line section 7 maint., Line sections 1 & 8 out.	0.0000003	0.0000005	0.171
Line section 8 maint., Line sections 1 & 7 out.	0.0000003	0.0000005	0.171

Outage rate due to component permanent outages overlapping component maintenance outages = 0.00315 f/yr.

Average duration of outages due to component permanent outages overlapping component maintenance outages = 3.130 Hours.

Outage rate due to component temporary outages overlapping component maintenance and permanent outages = 0.00708 f/yr.

TABLE 2.4

A SUMMARY OF THE RELIABILITY INDICES FOR VARIOUS LOAD POINTS IN FIGURE 2.4

Event	Load Point 3	Load Point 4	Load Point 5	Load Point 6
λ_{SL}, f/yr.	0.008720	0.008770	0.000220	0.001650
r_{SL}, hours	3.820	3.810	3.000	3.561
λ''_{ML}, f/yr.	0.003150	0.002690	0.000005	0.000960
r''_{ML}, hours	3.139	3.265	1.800	2.800
λ_{tL}, f/yr.	0.013660	0.016030	0.000109	0.003610

The third example considers a multi-circuit overhead transmission system shown in Figure 2.5[16]. The system consists of six transmission circuits between two stations 1 and 2. It is assumed that all buses are perfectly reliable and all breaker failures are ground faults. Current transformer failures are pooled with breaker failures. Component temporary and maintenance outages are disregarded for convenience. The failure criterion is expressed in terms of the largest number of circuits whose loss can still be tolerated. This number is varied from 0 to 2 to illustrate the application of the equations for first, second and third order cut sets. The component and weather statistics used in this example are given in Table 2.5. The system outage frequency and duration were calculated for different circuit lengths and for the conditions of occurrence and nonoccurrence of repairs during adverse weather. The results obtained are given in Table 2.6. It is noted that the system failure rate increases considerably with increasing length of the transmission

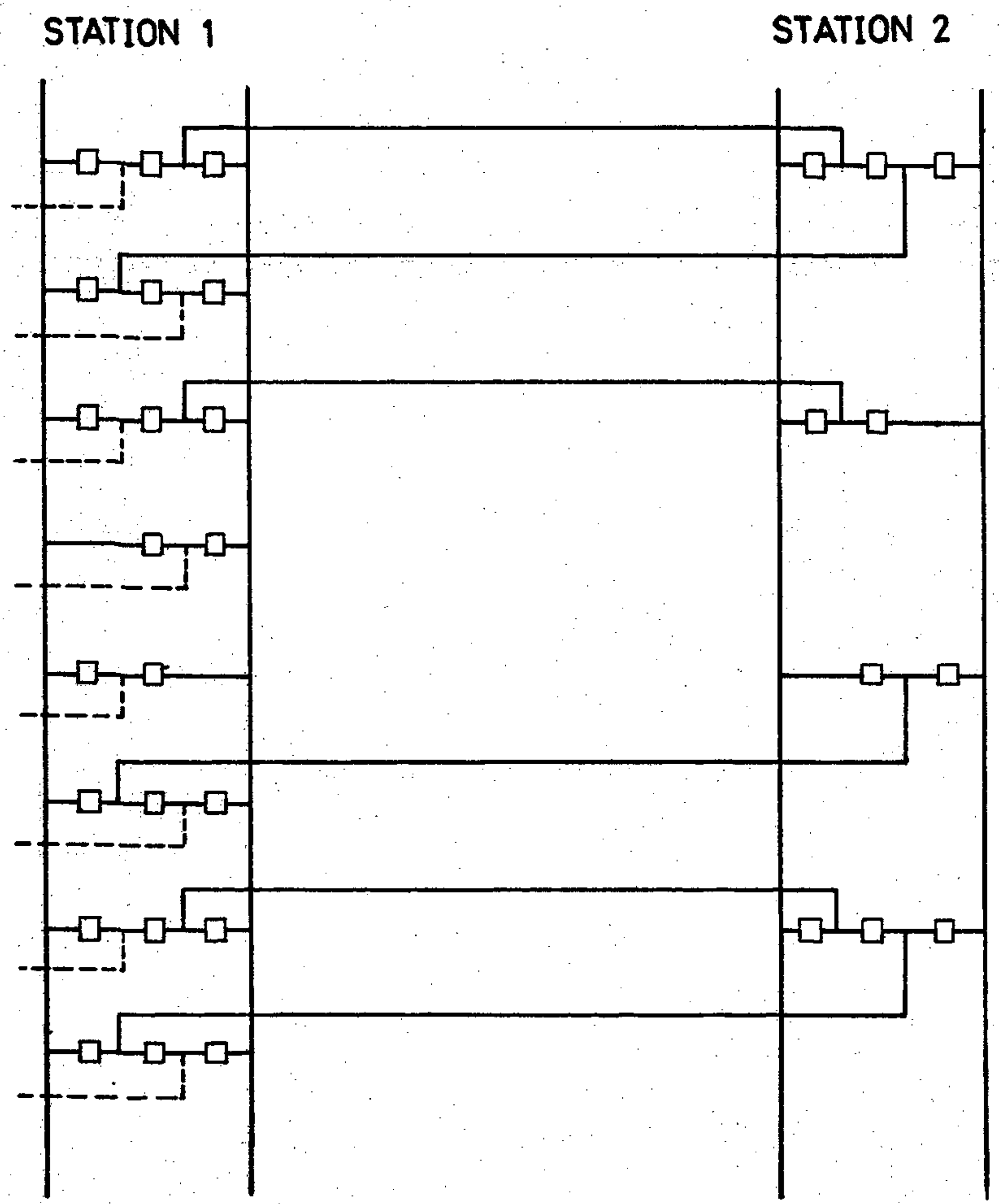


Figure 2.5 A Six Circuit Transmission Scheme

circuits. The system average outage duration also increases with the length of transmission line but not in the same proportion as the system outage rate. This is to be expected because as the transmission length increases, the system failure rate is dominated by the events involving line failures.

TABLE 2.5

COMPONENT AND WEATHER DATA FOR THE SYSTEM IN FIGURE 2.5

Component	λ f/yr	λ' f/yr	r hrs.	T_s hrs.
Line	0.00224/mi	0.435/mi	9.022	0.972
Breaker	0.0295	0.0295	40.30	0.972
Bus	---	---	---	---

N = 67.64 Hours S = 1.90 Hours

TABLE 2.6

OUTAGE RATE AND DURATION FOR SYSTEM IN FIG. 2.5

m = The number of circuits the loss of which can be tolerated.

No. of parallel circuits = 6 (Configuration Shown in Fig. 2.5)

Repair During Adverse Weather

	m = 0		m = 1		m = 2	
L, miles	λ;f/yr.	r,hrs.	λ;f/yr.	r;hrs.	λ;f/yr.	r,hrs.
50	4.98	7.87	0.1349	2.687	0.000985	2.60
100	9.26	8.41	0.3583	3.712	0.007741	2.82
150	13.54	8.60	0.7290	4.062	0.026067	2.88
200	17.82	8.70	1.2471	4.215	0.061735	2.92
250	22.10	8.76	1.9126	4.292	0.120657	2.93
300	26.37	8.80	2.7254	4.347	0.208404	2.95
350	30.65	8.83	3.6850	4.378	0.331055	2.95
400	34.92	8.86	4.7931	4.399	0.493837	2.96
450	39.20	8.87	6.0481	4.416	0.703592	2.97
500	43.48	8.89	7.4503	4.429	0.965451	2.97

Table 2.6 (cont'd)

Table 2.6: OUTAGE RATE AND DURATION FOR SYSTEM IN FIG. 2.5 (cont'd)

No Repair During Adverse Weather

	m = 0		m = 1		m = 2	
L, miles	λ;f/yr.	r,hrs.	λ;f/yr.	r;hrs.	λ;f/yr.	r,hrs.
50	4.98	9.24	0.1523	3.942	0.00196	4.04
100	9.26	9.87	0.4239	5.215	0.01396	4.56
150	13.54	10.10	0.8735	5.810	0.04600	4.69
200	17.82	10.22	1.5011	6.003	0.10792	4.75
250	22.10	10.29	2.3060	6.104	0.20970	4.78
300	26.37	10.34	3.2880	6.164	0.36124	4.80
350	30.65	10.38	4.4520	6.199	0.57261	4.81
400	34.92	10.41	5.7915	6.226	0.85350	4.82
450	39.20	10.43	7.3097	6.245	1.21410	4.83
500	43.48	10.45	9.0061	6.259	1.66400	4.84

This example was solved in reference 16 using a Markov approach which required an extensive amount of effort and computer time. The efficiency of the method of analysis presented in this thesis is again evident as the computer time required to obtain the reliability indices given in Table 2.6 was only 2.35 seconds.

2.6 Summary

The theoretically accurate techniques such as Markov analysis, Monte Carlo simulation approach etc. are quite difficult to apply for overall reliability analysis of transmission and distribution systems. This chapter has illustrated a technique in which a simple set of equations is used in conjunction with a cut set approach to evaluate system reliability indices. The method of analysis is sequential and straightforward. Each cut set is evaluated for its contribution to outage frequency and duration indices for each mode of failure. The simple equations described are quite flexible and can be easily modified to include other considerations which might be encountered in practical systems. The equations can be permanently stored in the computer memory and called in according to the conditions of weather, repair, maintenance, temporary outages, overload outages etc. as and when required. The basic requirement is to determine what device failure combinations will cause interruption. The three examples given clearly illustrate the computational efficiency of the method of analysis. The results as shown in Table 2.3 provide an effective physical appreciation of the system probabilistic performance and indicate various possible economical alternatives for reliability improvements.

3. QUANTITATIVE EVALUATION OF SUBSTATION AND SWITCHING STATION RELIABILITY PERFORMANCE

3.1 Introduction

Substations and switching stations are the points of energy transfer between transmission, subtransmission and distribution systems. At these points, lines interconnect, voltage transformations occur and system controls and protection are implemented. Evaluation of substation and switching station reliability performance therefore consists of assessing how adequately the basic elements are able to perform their functions.

It is evident from the existing literature that the bulk of the work in the quantitative evaluation of power system reliability has been in generation capacity studies[1]. During the last decade, considerable attention has been focused on reliability studies of transmission and distribution schemes. One of the main concerns has been the development of accurate and consistent models to represent the true component and system behaviour. As noted in the previous chapter, a two state weather model was developed to include environmental effects in the reliability predictions of overhead transmission and distribution systems[3]. In regard to the inclusion of circuit breakers and protective elements in transmission system analysis, a three state component model was described[16,20] which gives a more realistic representation of power system components than that given by the previous two state component models. In this model, when a component fails, the system protection may isolate a number of unfaulted components. Following which, through appropriate switching operations, all but the minimum number of components that must be kept out of service for the isolation of the failed component are restored to service as soon as possible. Thus a system component has three possible states namely, operating, before switching and after switching. The program as described in references 16 and 20 does not appear to be applicable to practical systems when:

(i) normally open breakers or switches are present in the system.

(ii) all circuit breaker failures are not ground faults.

(iii) the protective system is not perfectly reliable.

(iv) the weather conditions have significant effect on the component failure and repair rates.

(v) component overload outages are to be evaluated.

Two recent papers[21,22] described some new models and their incorporation in digital computer programs to provide a more realistic component and system representation.

In regard to the reliability evaluation of substations and switching stations, very little work has been reported[17,18,19,21]. The importance of station reliability performance is, however, now being recognized. A three paper session[23,24,25] was arranged by CEA in its recent Spring Meeting. This chapter describes the extension of the techniques available for reliability analysis of transmission and distribution systems to the evaluation of station reliability performance in terms of outage frequencies and durations. A computer program(21,25) is described to perform these reliability studies.

3.2 Component Failure Modes

Power system components can have many types of failures. In this chapter, system components are classified into two categories according to their failure types. The first category includes components such as transmission lines, transformers, reactors, buses etc.. These components can be in any of the following states:

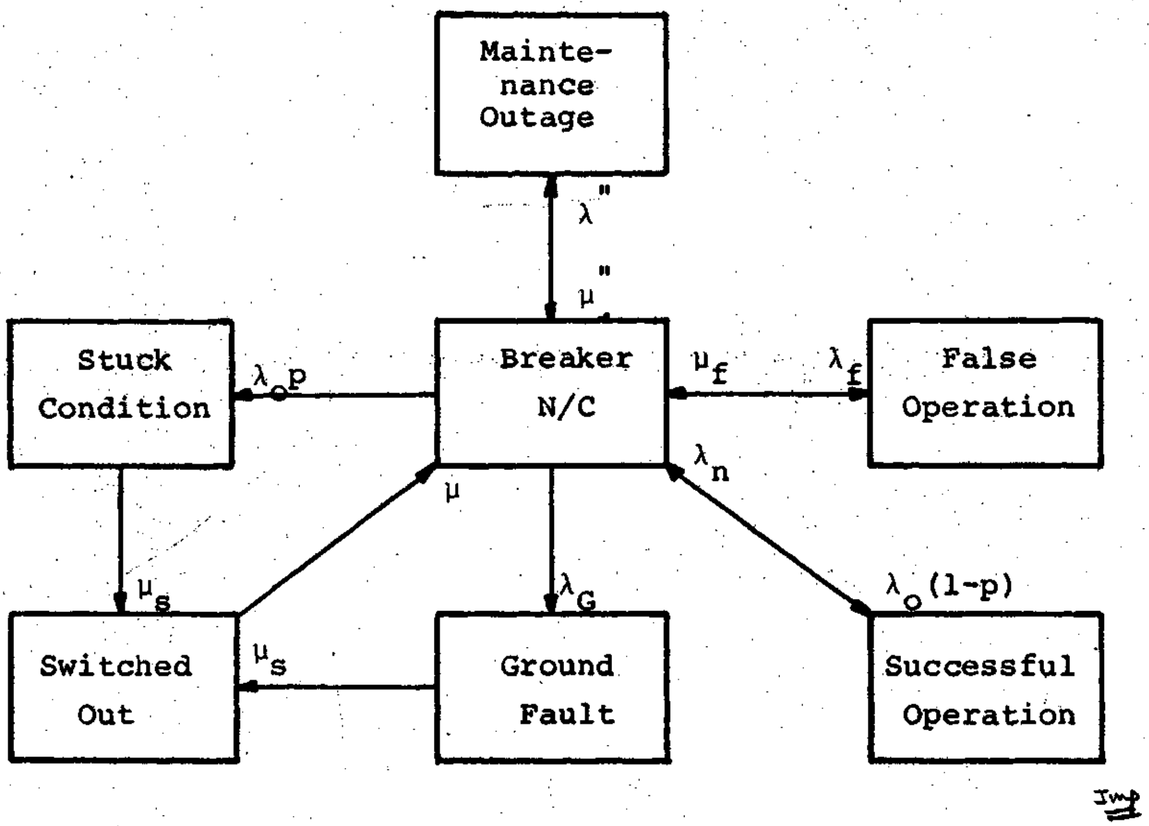
(i) Operating (ii) Faulted (iii) Out for repair or preventive maintenance.

In addition, if appropriate protection is not available, these components can have undetected open failures.

The second category includes components such as circuit breakers, reclosers, disconnect switches, carrier equipments etc.. These components can be in any of the following states:

(i) Operating (ii) Faulted (iii) Out for repair or preventive maintenance (iv) Stuck when called upon to operate or not closing when called upon to do so (v) Undetected open failure.

These states for a normally closed breaker are shown in Figure 3.1. It should be noted that the faulted state in the first category of components can be quite different from that in the second category. In the latter case, a second level of system protection should operate



λ_G = The ground fault rate of the breaker.

λ_o = The rate at which the breaker is called upon to operate.

λ_f = The false operation rate of the breaker.

λ'' = The maintenance outage rate of the breaker.

μ_s = The rate at which the breaker is switched out.

μ = The repair rate of the breaker.

μ_f = The repair rate for a false operation.

λ_n = The reciprocal of the mean time for breaker operation.

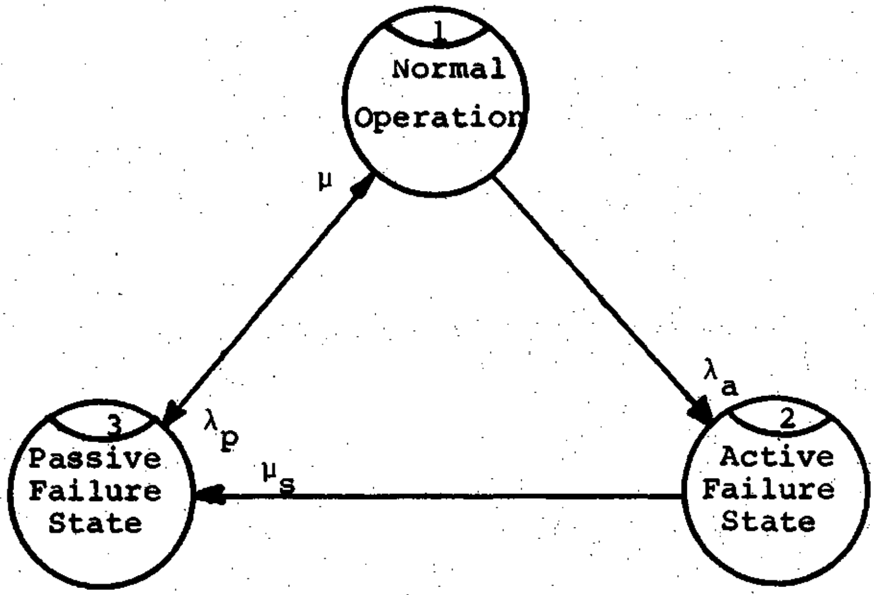
p = The probability of breaker becoming stuck.

Figure 3.1 State Space Model for a Normally Closed Breaker to isolate the faulted component, whereas in the former case the first level of system protection is required to operate.

It should be noted that different categories of component failure do not necessarily produce the same number of failure modes. Failure modes are classified according to the resulting types of system effect. For example, if a breaker has a fault or it fails to trip, then the resulting fault must be cleared by the back up equipment. This event must increase the extent of effect of the fault and represents one possible component failure mode. The other class of failures corresponds to a maintenance outage or a trip out in which the breaker is removed by switching and in which the extent of the outage is confined to the path involving the breaker. This represents another possible failure mode. Thus a new classification of component failures can be obtained on the basis of their system effects. According to this classification, component outages can be divided into active and passive failures. This is shown in Figure 3.2.

Active failures.

All component faults which result in the removal of certain other healthy components from service are classified as active failures. This class of failures includes component faults which cause operation of circuit breakers or disconnect switches. Passive failures. All component outages which do not remove any healthy components from service are classified as passive failures. These include undetected open failures, false trips etc.. The summation of active and passive failures therefore equals the total number of component failures.



λ_p = Component passive failure rate.

λ_a = Component active failure rate.

μ_s = Component switching rate.

μ = Component repair rate.

STATE PROBABILITIES

$$P_1 = \frac{1}{1 + \frac{\lambda_T}{\mu} + \frac{\lambda_a}{\mu_s}} \qquad P_2 = \frac{\lambda_a/\mu_s}{1 + \frac{\lambda_T}{\mu} + \frac{\lambda_a}{\mu_s}}$$

$$P_3 = \frac{\lambda_T/\mu}{1 + \frac{\lambda_T}{\mu} + \frac{\lambda_a}{\mu_s}} \qquad \lambda_T = \lambda_p + \lambda_a$$

STATE FREQUENCIES

$$f_1 \simeq \lambda_T \qquad f_2 \simeq \lambda_a \qquad f_3 \simeq \lambda_T$$

Figure 3.2 Component Active and Passive Failure Model.

3.3 Load Point Failure Modes

The simple system shown in Figure 3.3 has been utilized to illustrate various modes of load point failure. The various modes of interruption as considered in this thesis are as follows:

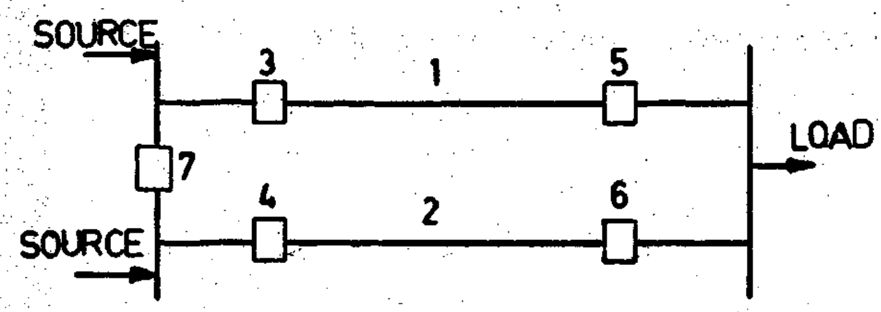


Fig. 3.3 - System For Illustration of Failure Modes

(i) Active failures of breakers 5, 6 and 7.

(ii) Active failures of breaker 3 when breaker 5 or 7 is stuck.

(iii) Active failures of breaker 4 when breaker 6 or 7 is stuck.

(iv) Active failure of line 1 when breaker 5 is stuck.

(v) Active failure of line 2 when breaker 6 is stuck.

(vi) Passive failure of breakers 4 or 6 or line 2 overlapping the passive failure of breakers 3 or 5 or line 1.

(vii) Passive failure of breakers 3 or 5 or line 1 overlapping the passive failure of breakers 4 or 6 or line 2.

It is assumed in the above that source and load buses are completely reliable. Circuit breakers are considered to be provided with isolators and the interruptions due to their active failures last only for the time required to operate the isolators. Continuity between source and load points is considered to be the criterion for successful system operation. The complexity of the problem can, therefore, be quickly realized from the large number of interruption modes associated with a simple system configuration such as that of Figure 3.3.

3.4 Reliability Analysis of Simple Substation Configurations

It is essential to perform reliability analysis on the various possible alternative substation designs before the selection of any particular configuration is made. The Whitemore Park distribution substation (11) of the Saskatchewan Power Corporation shown in Figure 3.4 is considered to illustrate the basic concepts involved in reliability calculations. There are two 25 KV incoming lines from the Regina switching station, one normally open and the

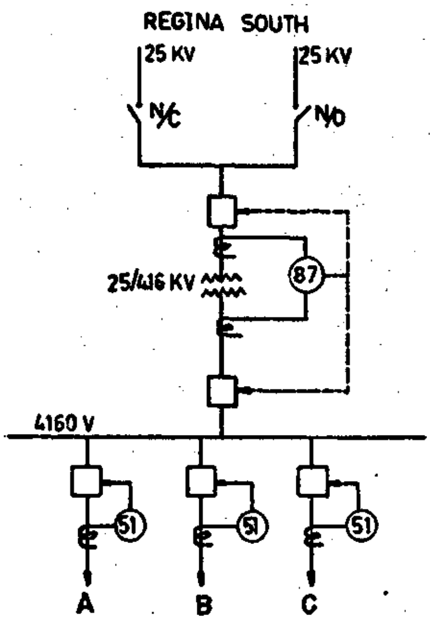


Figure 3.4 - Whitemore Park Distribution Substation

TABLE 3.2

INTERRUPTION ANALYSIS FOR CUSTOMERS AT POINT A

Failed Component	Failure Rate f/yr	Average Outage Time Hrs.	Total Outage Time Hrs/yr
25 KV Line	0.050	0.50	0.0250
25 KV Breaker	0.010	20.00	0.2000
25/4.16 KV Transformer	0.012	10.00	0.1200
4.16 KV Breaker	0.007	72.00	0.5040
4.16 KV Bus	0.007	3.50	0.0245
Feeder Breaker	0.010	20.00	0.2000
Feeder Breaker for B	0.005	1.00	0.0050
Feeder Breaker for C	0.005	1.00	0.0050
Feeder to Customer A	0.050	5.00	0.2500
	0.156	8.54	1.3335

$$\left[200 \times (\text{Outage Time at A}) + 250 \times (\text{Outage Time at B}) + 50 \times (\text{Outage Time at C})\right]$$

$$= 500 \times 1.33 \times 60 = 39900 \text{ minutes/yr.}$$

$$\text{Customer minutes out/customer/yr.} = \frac{39900}{500} \approx 80.$$

Using the technique described above, the simple substation configurations shown in Figure 3.5 have been evaluated manually in terms of their outage frequencies and durations. The component parameters used in these studies are given in Table 3.1. In order to simplify the analysis, normally open breakers and switches are assumed to be completely reliable. Maintenance conditions are not considered. The following two criteria were considered for successful system operation.

(i) Continuity of supply to any one of two load points A and B.

(ii) Continuity of supply to both the load points A and B.

The results obtained in terms of the outage rate and the total outage time per year for the above two modes

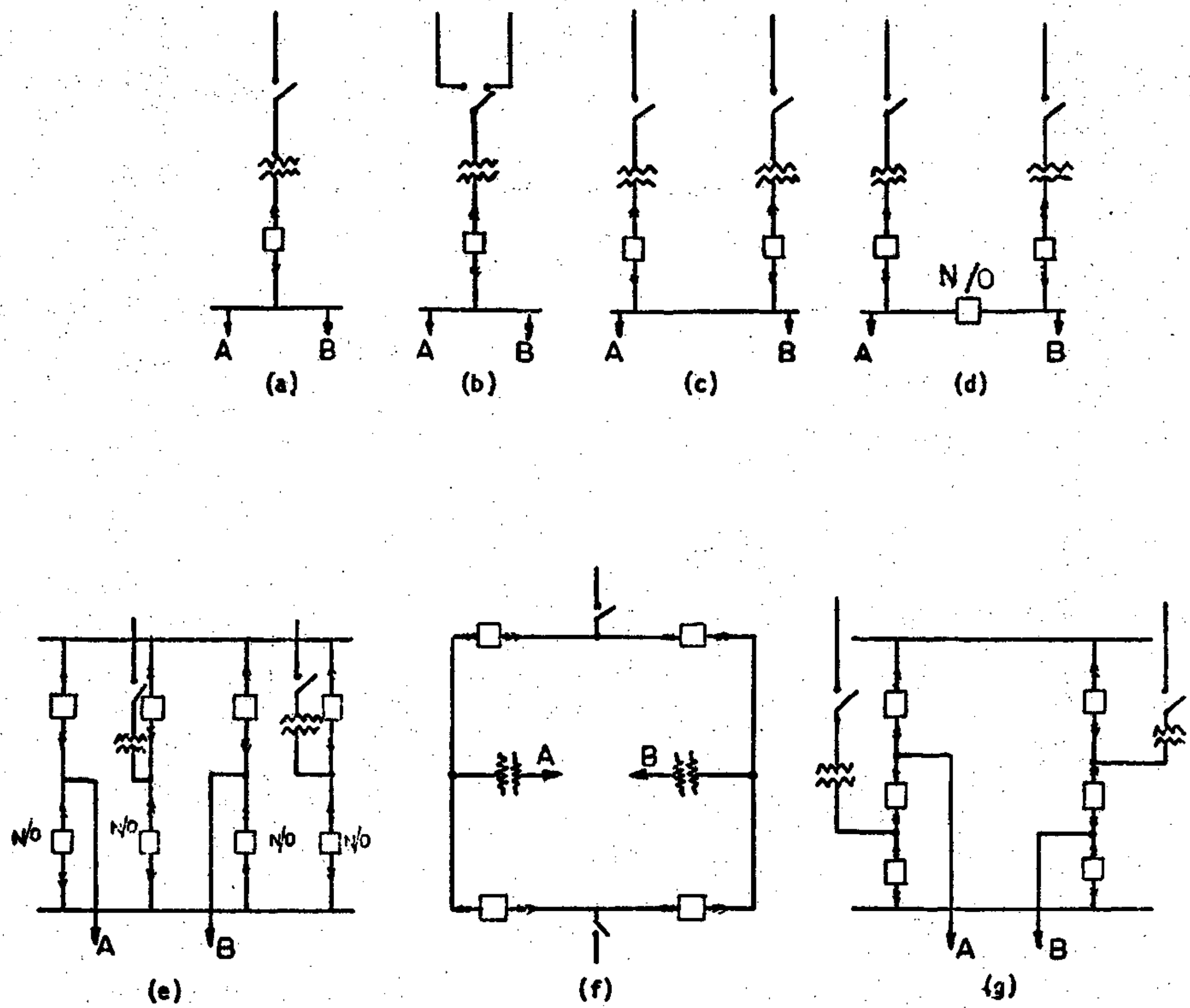


Figure 3.5 Some Simple Substation Configurations

of successful operation are shown in Figures 3.6 and 3.7. All circuit breaker failures are assumed to be ground faults (active failures) in Figure 3.6 whereas breakers are considered to be completely reliable in Figure 3.7. It is clear from these figures that the selection of a particular design from a reliability viewpoint depends upon the component data and the definition of successful system operation. If all breaker failures are ground faults, then:

(i) the first criterion of system successful operation gives preference to the system in Figure 3.5f from both outage rate and total outage time viewpoints.

(ii) the second criterion of system successful operation gives preference to systems in Figures 3.5c and 3.5d from the outage rate graph and to system 3.5g from the total outage time graph.

If breakers are considered to be completely reliable, then:

(i) the first criterion again gives preference to the system in Figure 3.5f from both outage rate and total outage time viewpoints.

(ii) the second criterion gives preference to the system in Figure 3.5g both from outage rate and total outage time graphs.

This analysis, therefore, clearly indicates the reliability implications associated with the definition of successful system operation and component and system parameters. It should be noted that the capital investment associated with each of the designs in Figure 3.5 can be

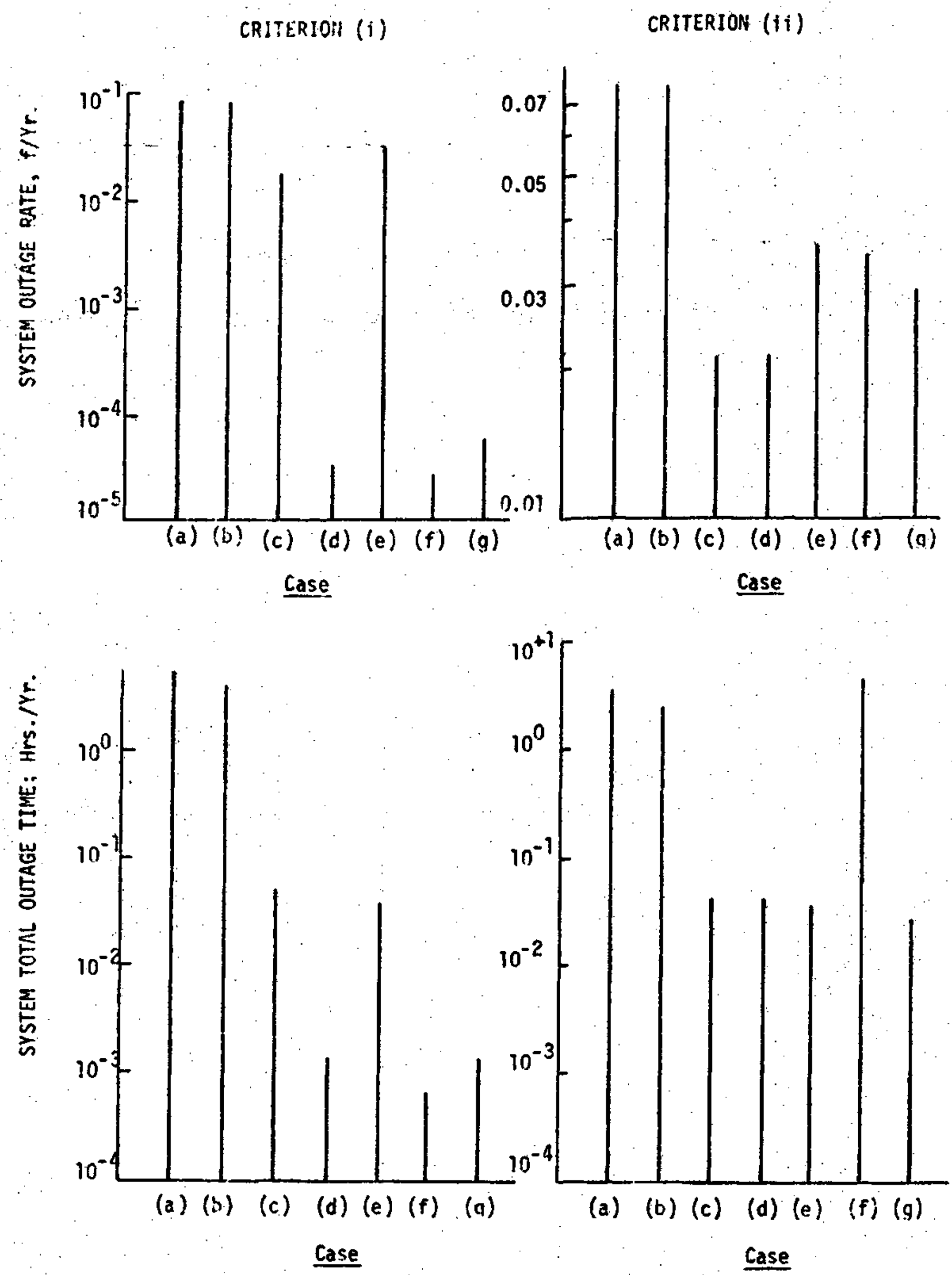


Figure 3.6 System Outage Rate and Total Outage Time for the Systems in Figure 3.5 (All Breaker Outages Active Failures)

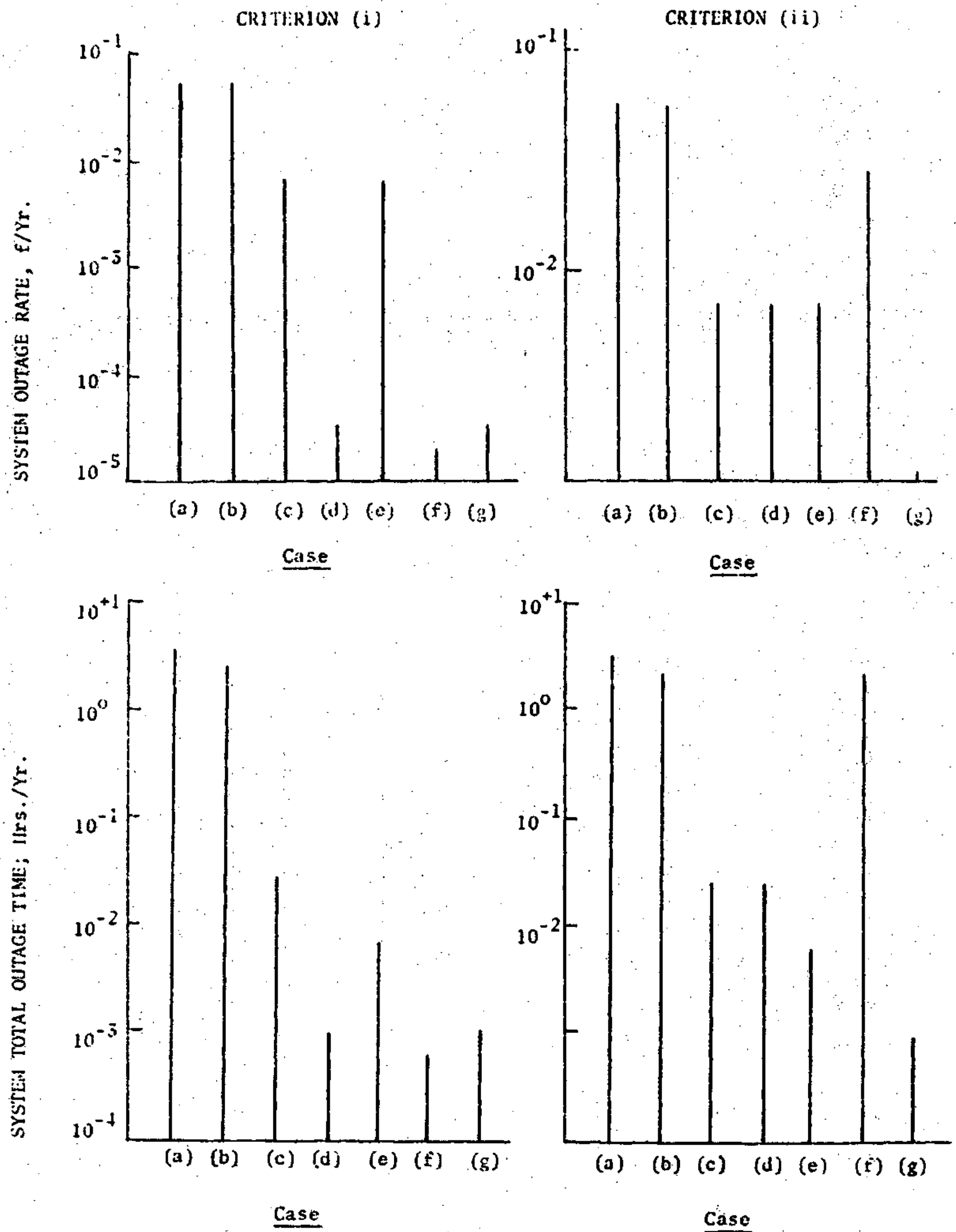


Figure 3.7 System Outage Rate and Total Outage Time For The Systems in Figure 3.5 (Breakers Completely Reliable)

easily calculated. Selection of a particular design can therefore include in quantitative form the associated reliability and economic constraints.

3.5 The Computer Program

The manual solution of reliability models of systems involving components with different failure modes becomes quite labourious and unmanageable, as the number of components and system complexity increase. The use of a state space approach[16], to include weather dependent failures and different repair and switching routines in reliability calculations, requires a solution of many simultaneous equations. In this section a computer program using the concept of component active and passive failures is described. The program is written in Fortran IV language for the IBM 370/158 computer. The only assumptions required are that the equations described in Chapter 2 are applicable. Two basic steps involved in the program are:

(i) the determination of all those events which cause interruption at the designated load point. The mode by which service can be restored is determined for each failure event.

(ii) the calculation of outage frequency and duration indices using equations appropriate for a particular failure mode.

In the first step, a failure modes and effects analysis is performed by algorithms programmed to select events and various possible combination of events within the system that can cause interruption to the load point under consideration. In the second step, equations described in Chapter 2 and in this section are used, according to the mode of failure, to evaluate the reliability indices.

The input to the program consists of the following:

(a) Number of components in the system, the normally open connections and times required to close normally open connections.

(b) Information about the configuration of the system under study. This information is provided by describing the components that immediately precede the component under consideration in the line of power flow.

(c) Component data. The following information is required on component reliability parameters.

(i) Component total outage rate

This rate represents the total number of times in a year the component has to be removed from service for repairs due to any of its failure modes. This failure rate includes both active and passive failures.

(ii) Component average repair time

This time represents the average of times required to repair all kinds of component failure modes. The repair action may be warranted due to component fault, a breaker or switch stuck condition, undetected open connection, breaker false operation etc.

(iii) Component maintenance outage rate

This rate is the average number of times in a year that a component is taken out of service for preventive maintenance.

(iv) Component average maintenance time

This value represents the average of all times spent in performing preventive maintenance actions on the component.

(v) Component active outage rate

This value is that fraction of the component total failure rate which corresponds to active failures of the component. The active outage rate is expressed in terms of the number of component active failures per year.

(vi) Component switching time

This is the time starting from the active failure of a component and lasting upto the time when the faulted component is removed from service and all other healthy components on the direct paths to the load point are restored to service. When other unfaulted components cannot be restored to service until the faulted component is repaired and put back into operation, the switching time value becomes the time required to repair the faulted component.

(vii) Stuck probability

This value represents the probability of a breaker or a switch being stuck when called upon to operate. In the case of normally open breakers or switches, this value is the probability of a breaker or switch not closing when called upon to do so. The stuck breaker probability is estimated from the ratio of the number of times the breaker fails to operate when called upon to do so to the total number of times the breaker is called upon to operate.

(viii) Weather parameters

If weather conditions are to be considered by using a two state weather model(8), the normal and adverse weather associated active and passive failure rates are required. The average durations of the two weather conditions are also specified.

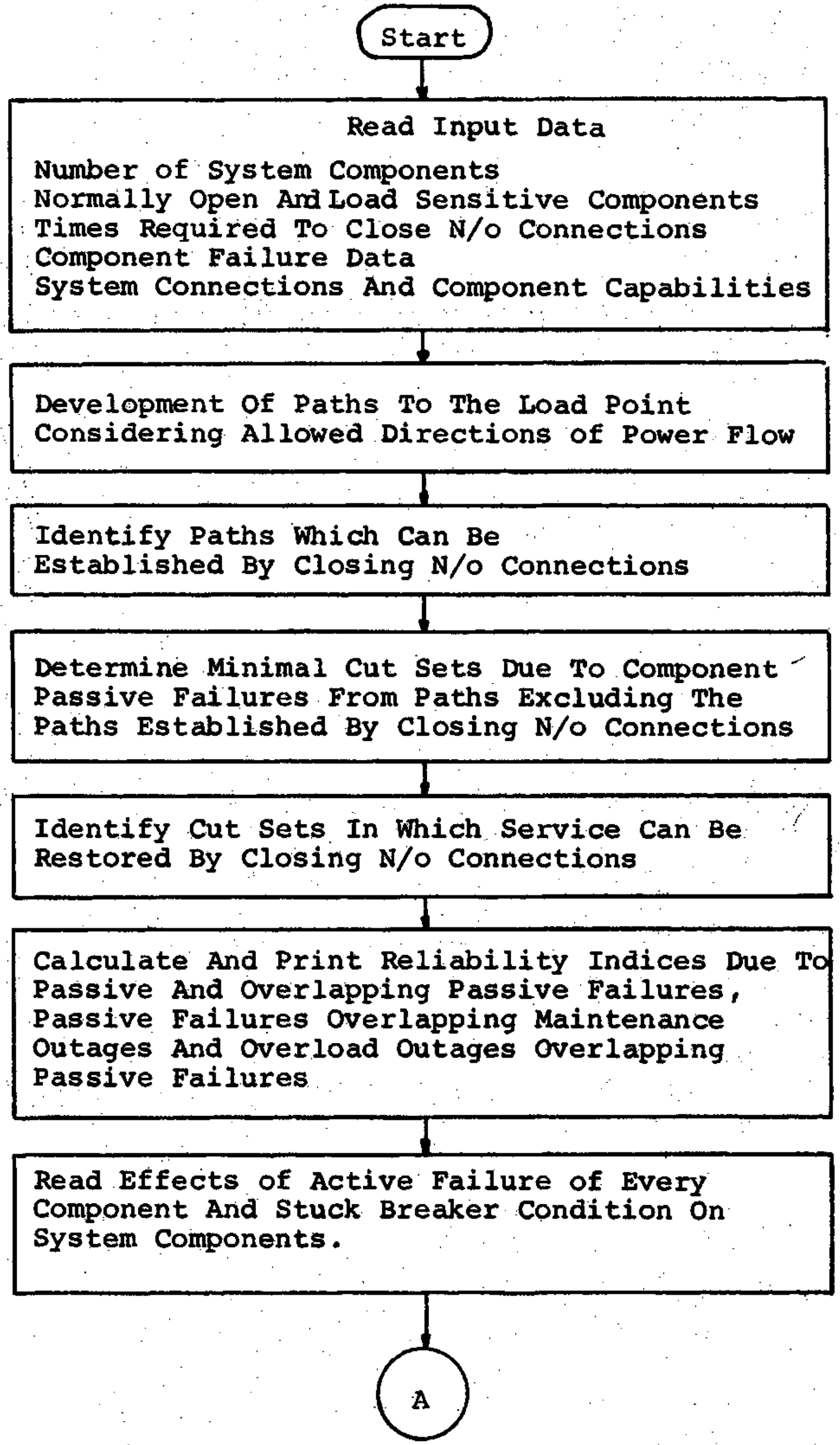
It must be noted that component passive failures have the same system effect as do the component maintenance outages. As such, these failure indices can be combined to obtain overall outage rates and durations. If this is done, then the equations used in the interruption analysis should take into consideration the dependent nature of maintenance, i.e., a maintenance outage cannot occur if there is some outage already existing in a related portion of the system. This is illustrated in Appendix C for a second order cut set. In this chapter, however, maintenance outages and passive failures are treated separately to maintain their individual identities.

(d) Identification of breakers which open as a result of component active failures. The breakers which open due to a combined active failure and stuck breaker condition are also identified for each component.

There can be some components in the system which are not on any direct transmission path to the load point under consideration but their active failures can interrupt some or all the direct paths. The total outage rates in the program are assigned zero values for such components. The average outage time is also assigned a zero value. Maintenance outages of such components cannot interrupt the direct transmission paths and thus the maintenance rate and outage time are assigned zero values. The active outage rate and switching time parameters, used in the program, are the actual values associated with the component. If the component cannot be switched out, then switching time is assigned a value equal to the component repair time.

The sequence of steps followed in the program is given in the flow chart shown in Figure 3.8. The program execution starts with the establishment of paths between the source point and the designated load point. These paths are established taking into consideration the allowed directions of power flow. (In certain components the reverse flow of power may not be allowed.) The paths which can be established by closing the normally open connections are also recognized.

The program execution then proceeds on to determining the minimal cut sets for the load point under consideration. This, in fact, consists of evaluating the various combinations of component passive failures within the system that can cause interruptions. The algorithm used in determining the minimal cut sets is based on boolean algebra and is very similar to that described in reference 26. It should be noted that these minimal cut sets are determined from only


Start
Read Input Data
Number of System Components
Normally Open And Load Sensitive Components
Times Required To Close N/o Connections
Component Failure Data
System Connections And Component Capabilities
Development Of Paths To The Load Point
Considering Allowed Directions of Power Flow
Identify Paths Which Can Be
Established By Closing N/o Connections
Determine Minimal Cut Sets Due To Component
Passive Failures From Paths Excluding The
Paths Established By Closing N/o Connections
Identify Cut Sets In Which Service Can Be
Restored By Closing N/o Connections
Calculate And Print Reliability Indices Due To
Passive And Overlapping Passive Failures,
Passive Failures Overlapping Maintenance
Outages And Overload Outages Overlapping
Passive Failures
Read Effects of Active Failure of Every
Component And Stuck Breaker Condition On
System Components.
A

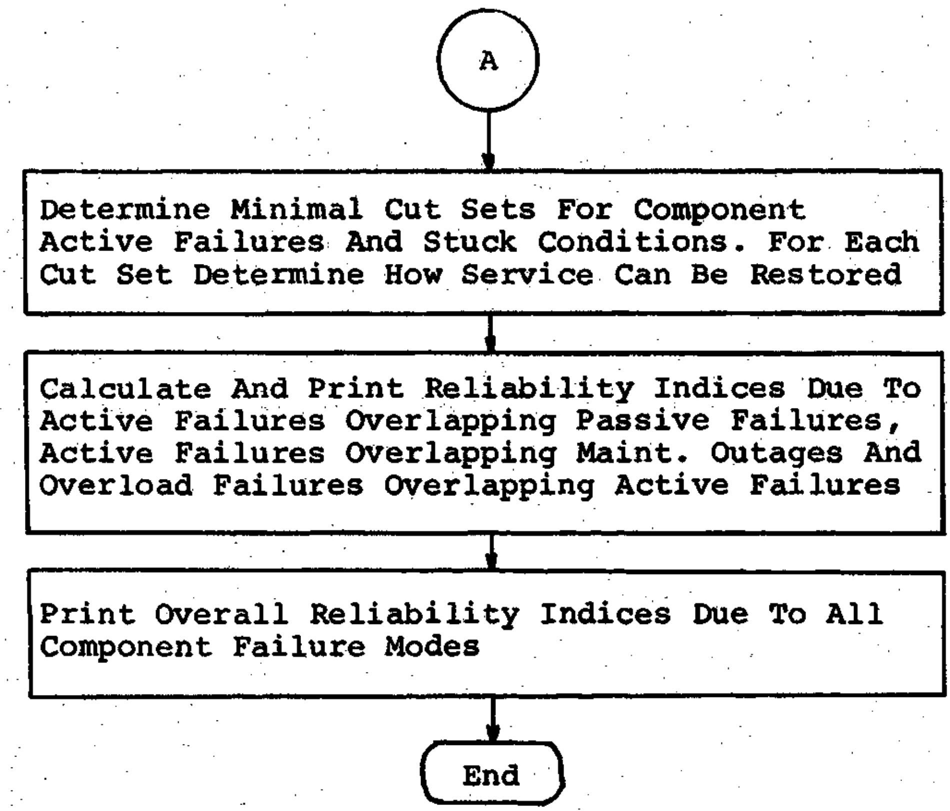


Figure 3.8 Flow Chart of the Computer Program.

those paths which are normally closed. A simple algorithm is then used to recognize those cut sets in which service can be restored by closing normally open paths.

When all the minimal cut sets have been determined, the computations are made for the contribution of each of the cut set to the following system reliability indices.

(i) The outage rate, the average duration and the total outage time due to passive failures and overlapping passive failures of components present in the cut set under consideration.

(ii) The outage rate, the average duration and the total outage time due to component passive failures overlapping the maintenance outage periods of components present in the cut set under consideration.

The above indices are computed by using the appropriate equations described in Chapter 2. These equations are stored in the computer as subroutines. If for a particular cut set, the service can be restored by closing a normally open path, the average outage duration for that cut set equals the time required to close the open path. When these computations have been made for all the cut sets, the total contributions to the load point reliability indices due to passive failures and passive failures overlapping maintenance outages are evaluated separately using component total outage rates.

In the next step, corresponding to each component active failure, minimal cut sets for the designated load point are determined by interrupting all those paths which contain unfaulted components but are on outage because of a fault on the component under consideration. If any of these cut sets has already been evaluated, it is not considered any further. The contribution to outage frequency and duration indices due to various cut sets associated with component active failures is evaluated by equations given in Table 3.3. When all the components have been considered, the contribution to the reliability indices due to combined active failures and stuck breaker conditions is evaluated on the same basis as is done for component active failures. At the end of this step, the total contribution to the load point reliability indices due to component active failures and breaker or switch stuck conditions is determined for the following two conditions.

(i) Component active failures and component active failures overlapping component passive failures.

(ii) Component active failures overlapping component maintenance outage periods.

When all the above computations are completed, the overall reliability indices are determined by combining the outage contributions of all active, passive and maintenance failure modes. These indices are (i) Total interruption rate, (ii) Average outage time, and (iii) The total average outage time.

The program has been written to handle a maximum of 50 components. It should, however, be noted that the limit to the number of components which can be handled by the program is determined only by the size of the computer available. The dimensions of the arrays in the program can be

TABLE 3.3

EQUATIONS FOR THE EVALUATION OF OUTAGES DUE TO COMPONENT ACTIVE FAILURES

Comps. in the Cut Set	Component Actively Failed	Comp. Stuck	Event	Contribution to System Failure Rate	Average Outage Duration Switching	Nonswitching
i	i	---	(a)	λ_{ig}	S_i	S_i
i,j	i	---	(a)	$\lambda_{ig}\lambda_j r_j + \lambda_j \lambda_{ig} S_i$	S_i	$\frac{S_i r_j}{S_i + r_j}$
			(b)	$\lambda_{ig}\lambda''_j r''_j$	S_i	$\frac{S_i r''_j}{S_i + r''_j}$
i	i	j	(a)	$\lambda_{ig} Pr(j)$	S_i	S_i
i,j	i	j	(a)	$\lambda_{ig} Pr(j)$	S_i	S_i
i,k	i	j	(a)	$\lambda_{ig}\lambda_k r_k Pr(j)$	S_i	$\frac{S_i r_k}{S_i + r_k}$
			(b)	$\lambda_{ig}\lambda''_k r''_k Pr(j)$	S_i	$\frac{S_i r''_k}{S_i + r''_k}$

Notes: In the above table,

Equations are described for cut sets upto second order and similar equations can be written for higher order cut sets.
Equations similar to those described in references 9 and 10 can be written to include failures in normal and adverse weather conditions.
λ_{ig} and S_i are respectively the active failure rate and the switching time of component i.
λ_j and r_j are respectively the total failure rate and the average repair time of component j.
λ''_k and r''_k are respectively the maintenance outage rate and the average maintenance time of component k.
Pr(j) is the probability of a breaker or switch j being stuck at any time.
Event (a) includes component active failures and component active failure overlapping component passive failures.

Event (b) includes component active failures overlapping component maintenance outage periods.

increased, if the computer size can accommodate a larger number of components.

3.6 System Studies

The computer program described in the previous section has been used in a number of practical system studies. In this section, two examples are given to illustrate the capabilities of the program.

The first example pertains to the reliability evaluation of a distribution substation shown in Figure 3.9. The system is considered to be failed if there is no continuous path from the source bus to the load bus. Table 3.4 gives the component data used in this reliability study. The detailed analysis of the configuration is given in Table 3.5. This table lists contingencies only up to second order. The program, however, computes higher order contingencies also and their contributions are added to the overall results.

It should be noted that in this example approximately 70% of the failures are attributed to single contingency events and 20% to events involving stuck breaker conditions. This clearly illustrates the importance of including protective system performance in reliability predictions. In addition, such information may be of value to designers to aid in review of design practices and to operators to aid in review of maintenance and testing practices as well as in training given personnel for testing and maintaining substations.

The overall reliability indices can be affected by changing the system configuration. The following variations for the system shown in Figure 3.9 were considered.

(a) Disconnects on the h.v. side of the transformer are replaced by h.v. breakers.

In this case failure parameters for h.v. breakers

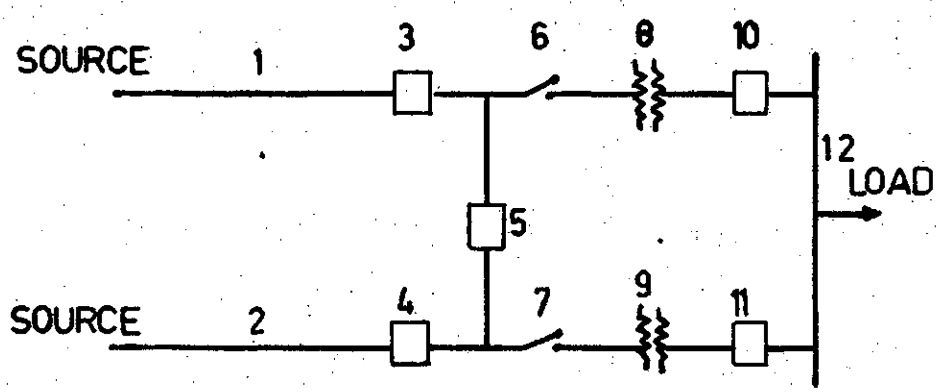


Fig. 3.9 A Distribution Substation Configuration

were assumed to be the same as those of the disconnects. The following events will not cause interruption if this change is made.

Breaker 3 suffers an active failure when breaker 10 is stuck.

Breaker 4 suffers an active failure when breaker 11 is stuck.

Transformer 8 suffers an active failure when breaker 5 is stuck.

Transformer 9 suffers an active failure when breaker 5 is stuck.

Transformer 8 suffers an active failure when line 2 is being repaired or maintained.

TABLE 3.4

COMPONENT DATA FOR SYSTEM IN FIGURE 3.9

Components	Total Outage Rate f/yr.	Average Outage Duration Hrs.	Maint. Rate o/yr.	Maint. Time Hrs.	Active Outage Rate f/yr.	Switching Time Hrs.	Stuck Prob.
Lines (1,2)	0.09	7.33	1.0	8.0	0.09	1.0	---
H.V. Breakers (3,4,5)	0.23	11.13	0.25	24.0	0.03	2.0	0.005
Disconnect Switches (6,7)	0.22	2.09	0.25	4.0	0.02	3.0	---
Transformers (8,9)	0.10	1000.0	0.50	48.0	0.10	1.0	---
L.V. Breakers (10,11)	0.02	3.0	0.25	12.0	0.01	1.0	0.06
L.V. Bus (12)	0.024	2.0	0.00	0.0	0.024	2.0	---

TABLE 3.5

DETAILED RELIABILITY ANALYSIS OF SUBSTATION CONFIGURATION OF FIGURE 3.9

(Contingencies only up to second order are listed)

Failure Events	Contribution Due To Non-Maintenance Events			Contribution Due To Maintenance Events		
	Outage Rate F/yr.	Av. Duration Hrs.	Total Outage Time Hrs./Yr.	Outage Rate F/Yr.	Av. Duration Hrs.	Total Outage Time Hrs./Yr.
Overlapping passive failures and maint. outages						
L.V. Bus, 12	0.240E-01	2.00	0.480E-01	0.	0.	0.
Lines 1 & 2	0.135E-04	3.66	0.496E-04	0.164E-03	3.83	0.628E-03
Line 1 & Bkr. 4	0.436E-04	4.42	0.193E-03	0.271E-03	4.87	0.132E-02
Line 2 & Bkr. 3	0.436E-04	4.42	0.193E-03	0.271E-03	4.87	0.132E-02
Bkr. 3 & Bkr. 4	0.134E-03	5.56	0.748E-03	0.315E-03	7.60	0.239E-02
Disconnects 6 & 7	0.231E-04	1.04	0.241E-04	0.502E-04	1.37	0.689E-04
Disconnect 6 & Trans. 9	0.252E-02	2.08	0.525E-02	0.614E-03	2.04	0.125E-02
Disconnect 6 & Bkr. 11	0.255E-05	1.23	0.315E-05	0.776E-04	1.78	0.138E-03
Disconnect 7 & Trans. 8	0.252E-02	2.08	0.525E-02	0.614E-03	2.04	0.125E-02
Disconnect 7 & Bkr. 10	0.255E-05	1.23	0.315E-05	0.776E-04	1.78	0.138E-03
Transformers 8 & 9	0.228E-02	500.00	0.114E-01	0.548E-03	45.80	0.251E-01
Trans. 8 and Bkr. 11	0.229E-03	2.99	0.685E-03	0.890E-04	6.30	0.561E-03
Trans. 9 and Bkr. 10	0.229E-03	2.99	0.685E-03	0.890E-04	6.30	0.561E-03
Breaker 10 and Bkr. 11	0.274E-06	1.50	0.411E-06	0.137E-04	2.40	0.328E-04
Total Contributions	0.320E-01	37.53	0.120E+01	0.319E-02	10.87	0.348E-01

Table 3.5 (cont'd)

Table 3.5: DETAILED RELIABILITY ANALYSIS OF SUBSTATION CONFIGURATION OF FIGURE 3.9 (cont'd)

Failure Events	Contribution Due To Non-Maintenance Events			Contribution Due To Maintenance Events		
	Outage Rate F/yr.	Av. Duration Hrs.	Total Outage Time Hrs./Yr.	Outage Rate F/Yr.	Av. Duration Hrs.	Total Outage Time Hrs./Yr.
Component Active failures overlapping passive & maint. failures						
Bkr. 3 A.F., Disconnect 7 out	0.383E-05	2.00	0.767E-05	0.342E-05	2.00	0.685E-05
Bkr. 3A.F., Trans. 9 out	0.343E-03	2.00	0.686E-03	0.822E-04	2.00	0.164E-03
Bkr. 3 A.F., Bkr. 11 out	0.274E-06	2.00	0.548E-06	0.103E-04	2.00	0.205E-04
Bkr. 4 A.F., Disconnect 6 out	0.383E-05	2.00	0.767E-05	0.342E-05	2.00	0.685E-05
Bkr. 4 A.F., Trans. 8 out	0.343E-03	2.00	0.686E-03	0.822E-04	2.00	0.164E-03
Bkr. 4 A.F., Bkr. 10 out	0.274E-06	2.00	0.548E-06	0.103E-04	2.00	0.205E-04
Bkr. 5 A.F.	0.300E-01	2.00	0.600E-01	0.	0.	0.
Disconnect 6 A.F., Line 2 out	0.171E-05	2.13	0.364E-05	0.183E-04	2.18	0.398E-04
Disconnect 6 A.F., Bkr. 4 out	0.689E-05	2.36	0.163E-04	0.137E-04	2.67	0.365E-04
Disconnect 7 A.F., Line 1 out	0.171E-05	2.13	0.364E-05	0.183E-04	2.18	0.398E-04
Disconnect 7 A.F., Bkr. 3 out	0.689E-05	2.36	0.163E-04	0.137E-04	2.67	0.365E-04
Trans. 8 A.F., Line 2 out	0.856E-05	1.00	0.856E-05	0.913E-04	1.00	0.913E-04
Trans. 8 A.F., Bkr. 4 out	0.344E-04	1.00	0.344E-04	0.685E-04	1.00	0.685E-04
Trans. 9 A.F., Line 1 out	0.856E-05	1.00	0.856E-05	0.913E-04	1.00	0.913E-04
Trans. 9 A.F., Bkr. 3 out	0.344E-04	1.00	0.344E-04	0.685E-04	1.00	0.685E-04
Bkr. 10 A.F.	0.100E-01	1.00	0.100E-01	0.	0.	0.
Bkr. 11 A.F.	0.100E-01	1.00	0.100E-01	0.	0.	0.

Table 3.5 (cont'd)

Table 3.5: DETAILED RELIABILITY ANALYSIS OF SUBSTATION CONFIGURATION OF FIGURE 3.9 (cont'd)

Failure Events	Contribution Due To Non-Maintenance Events			Contribution Due To Maintenance Events		
	Outage Rate F/yr.	Av. Duration Hrs.	Total Outage Time Hrs./Yr.	Outage Rate F/Yr.	Av. Duration Hrs.	Total Outage Time Hrs./Yr.
Active failures and Stuck Bkrs.						
Bkr. 3 A.F., Bkr. 5 stuck	0.150E-03	2.00	0.300E-03	0.	0.	0.
Bkr. 3 A.F., Bkr. 10 stuck	0.180E-02	2.00	0.360E-02	0.	0.	0.
Bkr. 4 A.F., Bkr. 5 stuck	0.150E-03	2.00	0.300E-03	0.	0.	0.
Bkr. 4 A.F., Bkr. 11 stuck	0.180E-02	2.00	0.360E-02	0.	0.	0.
Disconnect 6 A.F., Bkr. 11 stuck	0.120E-02	1.50	0.180E-02	0.	0.	0.
Disconnect 6 A.F., Bkr. 5 stuck	0.100E-03	2.36	0.236E-03	0.	0.	0.
Disconnect 7 A.F., Bkr. 11 stuck	0.120E-02	1.50	0.180E-02	0.	0.	0.
Disconnect 7 A.F., Bkr. 5 stuck	0.100E-03	2.36	0.236E-03	0.	0.	0.
Trans. 8 A.F., Bkr. 10 stuck	0.600E-02	1.00	0.600E-02	0.	0.	0.
Trans. 8 A.F., Bkr. 5 stuck	0.500E-03	1.00	0.500E-02	0.	0.	0.
Trans. 9 A.F., Bkr. 11 stuck	0.600E-02	1.00	0.600E-02	0.	0.	0.
Trans. 9 A.F., Bkr. 5 stuck	0.500E-03	1.00	0.500E-03	0.	0.	0.
Total Contributions	0.703E-01	1.51	0.106E+00	0.575E-03	1.49	0.856E-03

Overall reliability indices

Failure rate = 0.106112 f/yr., Av. outage duration = 12.67 hrs.,
Total outage time = 1.344 hrs./yr.

Transformer 9 suffers an active failure when line 1 is being repaired or maintained.

The system outage rate decreases from 0.106112 f/yr. to 0.101110 f/yr. with this change. The total outage time decreases from 1.344 hrs./yr. to 1.336 hrs./yr. It is, therefore, evident that this change in the configuration brings about an insignificant change in the system reliability indices.

(b) Breaker 5 is normally open.

If it is assumed that breaker 5 in the normally open mode cannot have any active failure, some of the events listed in Table 3.4 are eliminated while a few new failure modes are added. The system overall reliability indices for this change are:

$$\lambda_{SL} = 0.08396 \text{ f/yr.}, \; r_{SL} = 15.50 \text{ hrs.}, \; \lambda_{SL}.r_{SL} = 1.3016 \text{ hrs./yr.}$$

where λ_{SL}, r_{SL} and $\lambda_{SL}.r_{SL}$ are respectively the system outage rate, the average outage duration and the total outage time.

It is, therefore, evident that this change produces a significant decrease in the system outage rate whereas the total outage time is not affected very much. If in the normally closed configuration, breaker 5 is assumed to be completely reliable, the system overall reliability indices are:

$$\lambda_{SL} = 0.076112 \text{ f/yr.}, \; r_{SL} = 16.88 \text{ hrs.}, \; \lambda_{SL}r_{SL} = 1.284 \text{ hrs./yr.}$$

This shows that the reliability of breaker 5 has a significant effect on the system outage rate. This is because all active failures of breaker 5 will cause interruption at the load point.

(c) Breakers on the h.v. side of transformers and disconnects on l.v. side.

The overall reliability indices resulting from this change are:

$$\lambda_{SL} = 0.3733 \text{ f/yr.}, \; r_{SL} = 4.645 \text{ hrs.}, \; \lambda_{SL} r_{SL} = 1.734 \text{ hrs./yr.}$$

It is clear from these results that there is a considerable increase in system outage rate and total outage time. The average outage duration decreases because of increase in the number of relatively short duration outages.

(d) l.v. breakers are replaced by disconnects and a sectionalizing breaker is connected in the l.v. bus.

The overall reliability indices associated with this configuration are as follows:

$$\lambda_{SL} = 0.2361 \text{ f/yr.}, \; r_{SL} = 6.50 \text{ hrs.}, \; \lambda_{SL} r_{SL} = 1.53 \text{ hrs/yr.}$$

There is again, a considerable increase in system outage rate and total outage time indices.

(e) Breakers and disconnects on the h.v. side are interchanged.

The overall system reliability indices associated with this changed configuration are as follows:

$$\lambda_{SL} = 0.10605 \text{ f/yr.}, \; r_{SL} = 13.22 \text{ hrs.}, \; \lambda_{SL} . r_{SL} = 1.402 \text{ hrs/yr.}$$

This change in configuration, therefore, results in insignificant decrease in system outage rate and increase in total outage time.

It should be noted, however, that superiority of a particular design cannot be judged from the average duration index. A design may have the same number of long interruptions as another design but the average duration may be diluted by additional sustained interruptions whose duration is limited by the short switching times.

Utilizing the base system configuration shown in Figure 3.9, the effects on the system reliability indices of varying the component parameters are shown in Figures 3.10, 3.11 and 3.12. Figure 3.10 shows the effect on the system outage rate of l.v. and h.v. breaker active failure rates. It is clear that, in this example, if the same percentage of improvement is made in the h.v. and l.v. breaker failure rates, the system outage rate will decrease considerably with h.v. breaker improvement. The total outage time is not greatly affected by any of these improvements as the main contribution to the system total outage time is due to transformer outages. Figure 3.11 shows the effect on the system outage rate of varying the l.v. and h.v. breaker stuck probabilities. This figure shows that, in this system configuration, if the same percentage of improvement is made in h.v. and l.v. breaker stuck probabilities, the system outage rate will decrease rapidly with l.v. breaker improvement. The total outage time again is not affected by any of these improvements. Figure 3.12 shows the effect on system outage rate and total outage time of a percentage improvement in the outage parameters of the transformers and lines. It is clear that, in the system under consideration, improvement in reliability performance

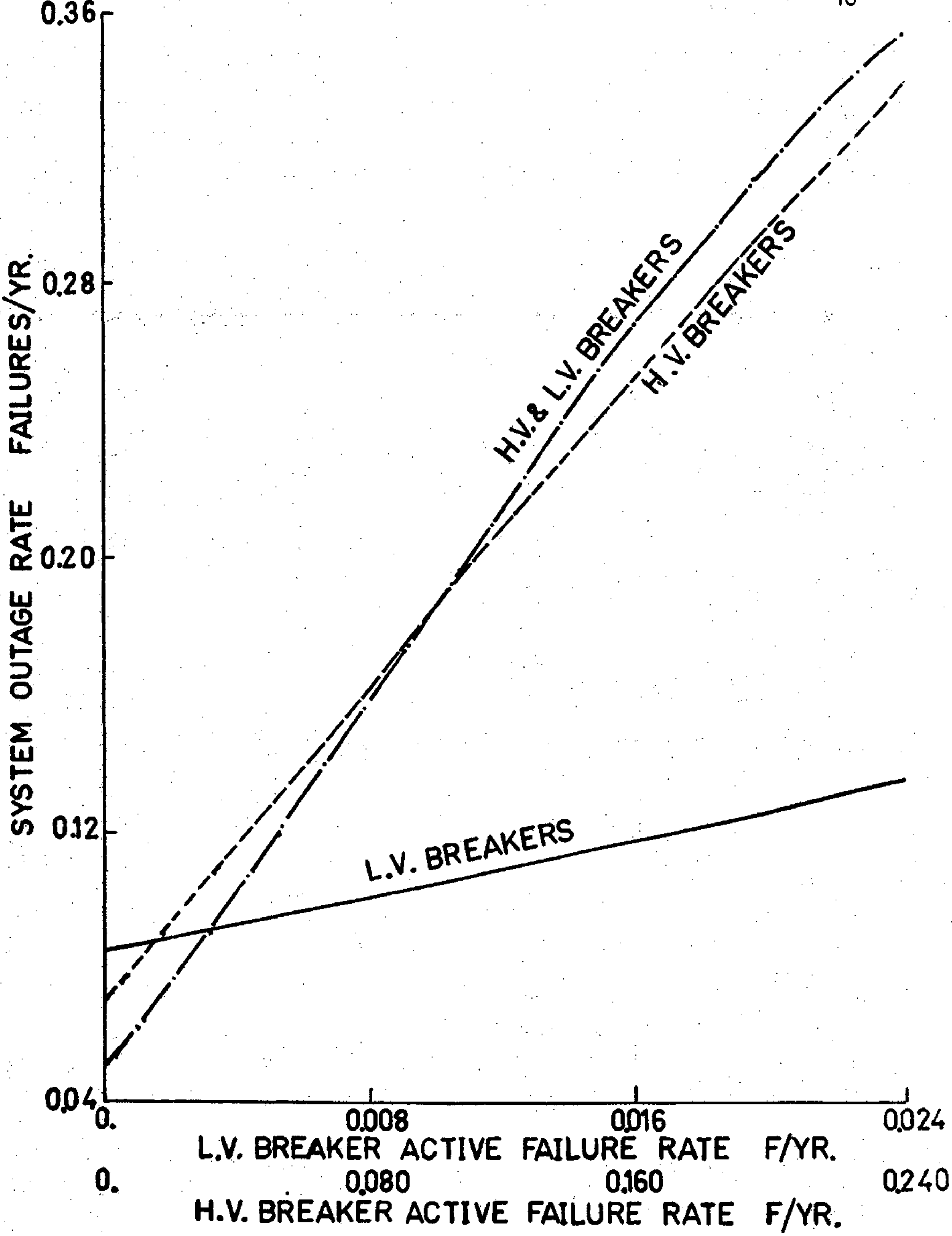


Figure 3.10 Effect on System Outage Rate of Varying Breaker Active Failure Rates.

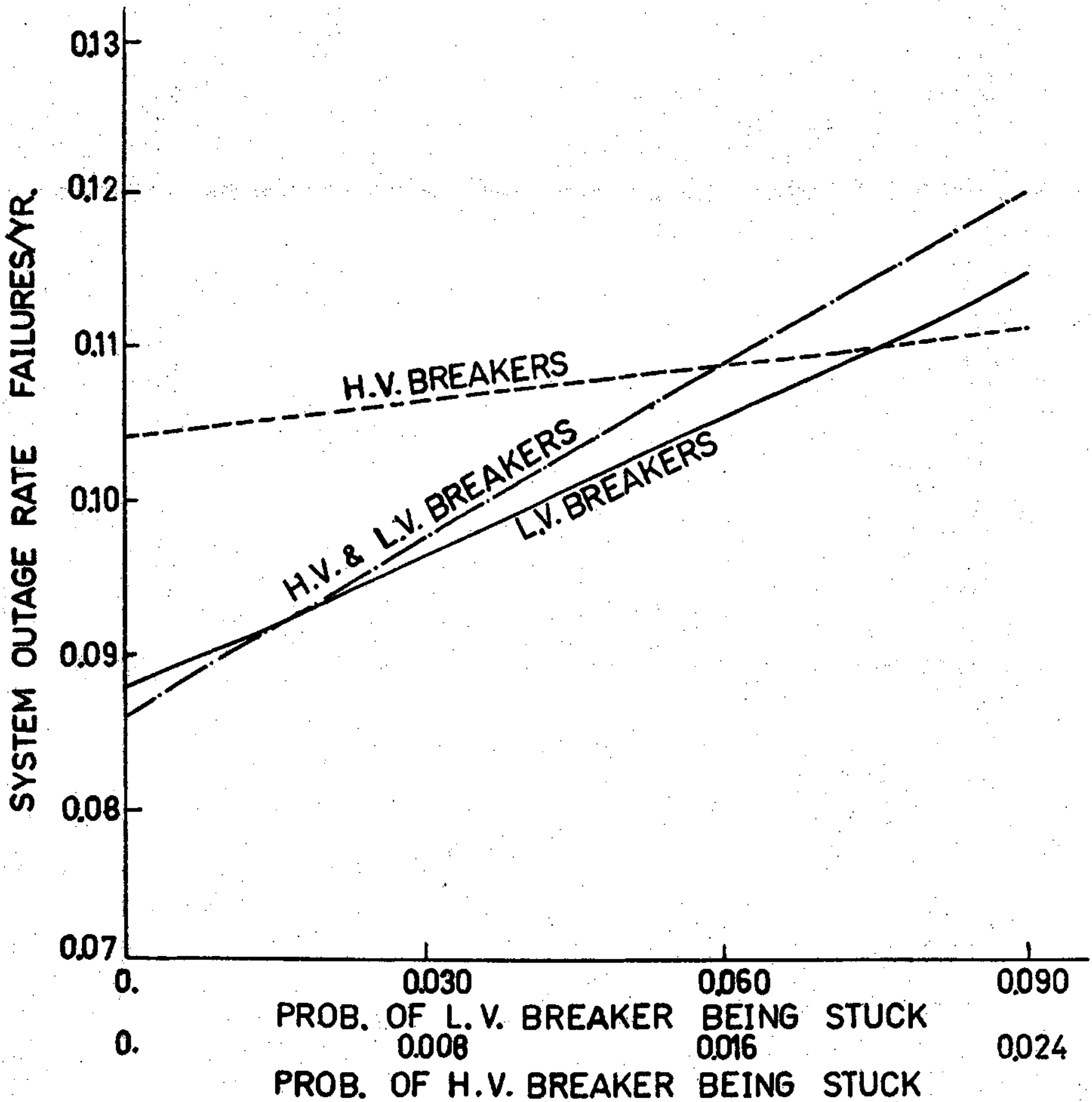


Figure 3.11 Effect on System Outage Rate of Varying Breaker Stuck Probabilities.

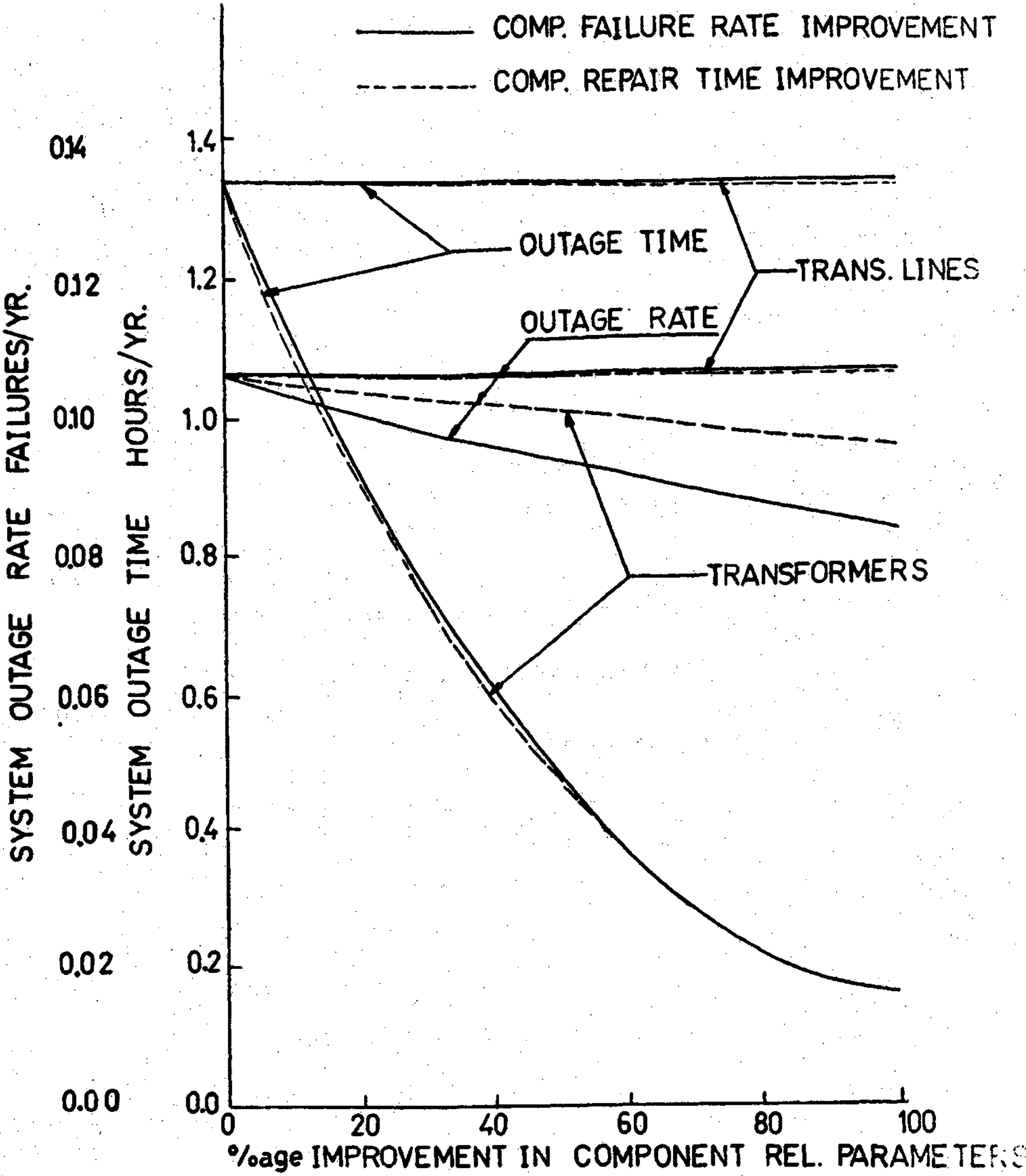


Figure 3.12 Effect on System Outage Rate and Total Outage Time of Percentage Improvement in Component Reliability Performance.

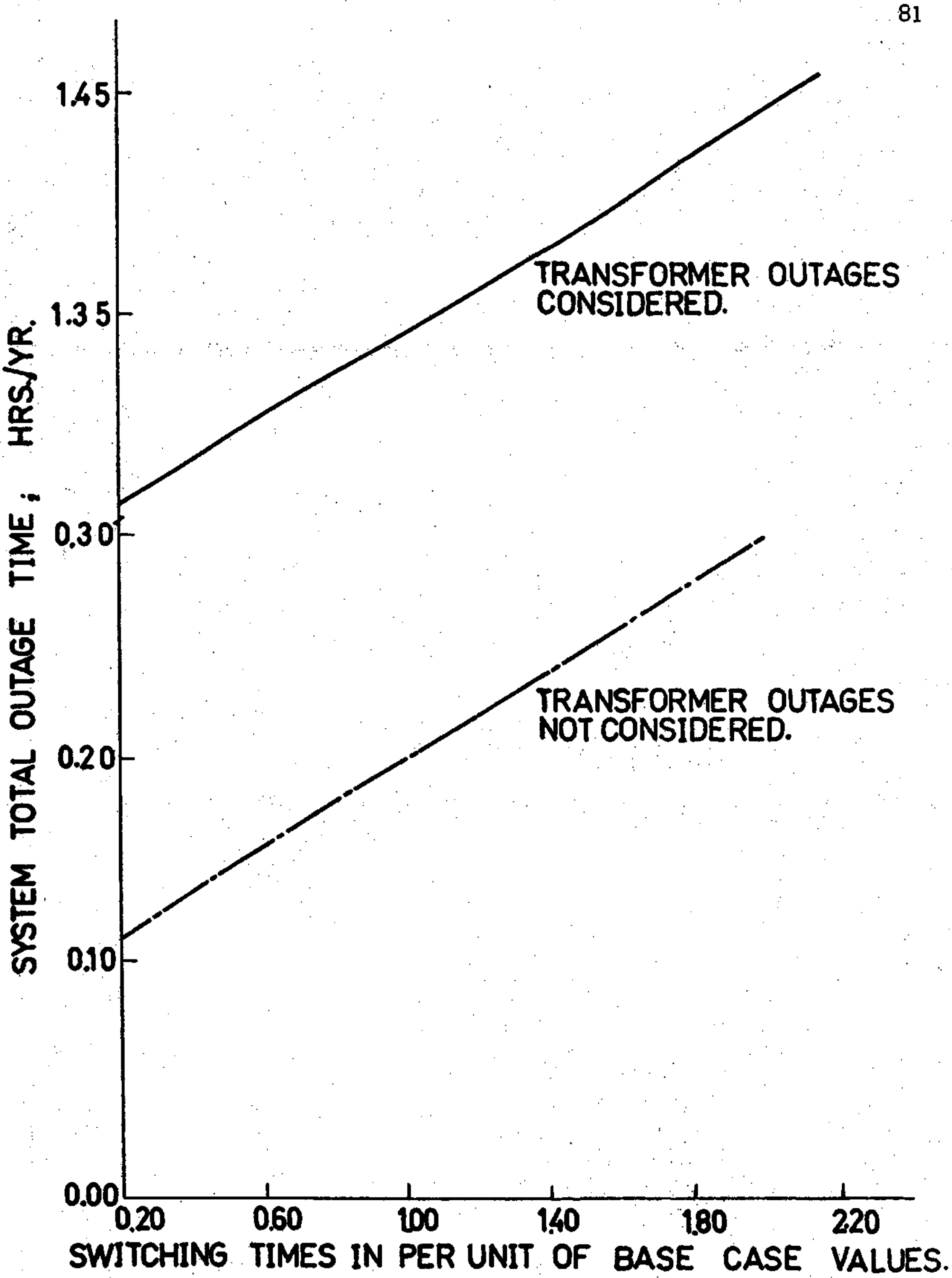


Figure 3.13 Effect on System Total Outage Time of Varying Switching Times.

of the transmission lines does not have significant effect on the system indices. The system outage rate and total outage time, however, are significantly decreased by improvements in the transformer reliability performance. The effect of varying component switching times on system total outage time is shown in Figure 3.13. There is no significant decrease in system outage time because the main contribution to this index is made by transformer outages. The variation in system outage time, if contribution due to transformer outages is excluded, is also shown in Figure 3.13. The system outage rate is not affected by varying the switching times.

The second example utilizes the Regina switching station of the Saskatchewan Power Corporation. The single line diagram for this station is shown in Figure 3.14. The criterion of successful operation is considered to be the continuity of supply at the far end of lines R1P and R2P (i.e. the Pasqua bus). All breaker failures are assumed to be active and the stuck breaker probability is considered to be zero. The following component parameters were used in the reliability study.

<u>Lines 1, 3 and 5</u>

$\lambda = 0.028$ f/yr., $r = 5.0$ hrs., $\lambda'' = 1.0$ o/yr, $r'' = 10.0$ hrs.

<u>Buses 6 and 11</u>

$\lambda = 0.007$ f/yr., $r = 3.5$ hrs., $\lambda'' = 1.0$ o/yr., $r'' = 15.0$ hrs.

<u>Transformers 2 and 4</u>

$\lambda = 0.012$ f/yr., $r = 168.0$ hrs., $\lambda'' = 2.0$ o/yr., $r'' = 13.0$ hrs.

<u>Lines 17 and 18</u>

λ = 0.05 f/yr., r = 4.0 hrs., λ'' = 0.5 o/yr., r'' = 4.5 hrs.

<u>Circuit breakers</u>

λ = 0.007 f/yr., r = 70.0 hrs., λ'' = 2.0 o/yr., r'' = 11.5 hrs.

Switching time = 1.5 hrs.

Assuming the allowed direction of power flow at point A as shown in Figure 3.14, the system reliability indices are:

λ_{SL} = 0.000268 f/yr., r_{SL} = 3.17 hrs., $\lambda_{SL}r_{SL}$ = 0.000849 hrs./yr.

When line B2R is considered to be normally open, with switching time equal to one hour, the following results are obtained:

λ_{SL} = 0.000621 f/yr., r_{SL} = 1.936 hrs., $\lambda_{SL}r_{SL}$ = 0.001202 hrs./yr.

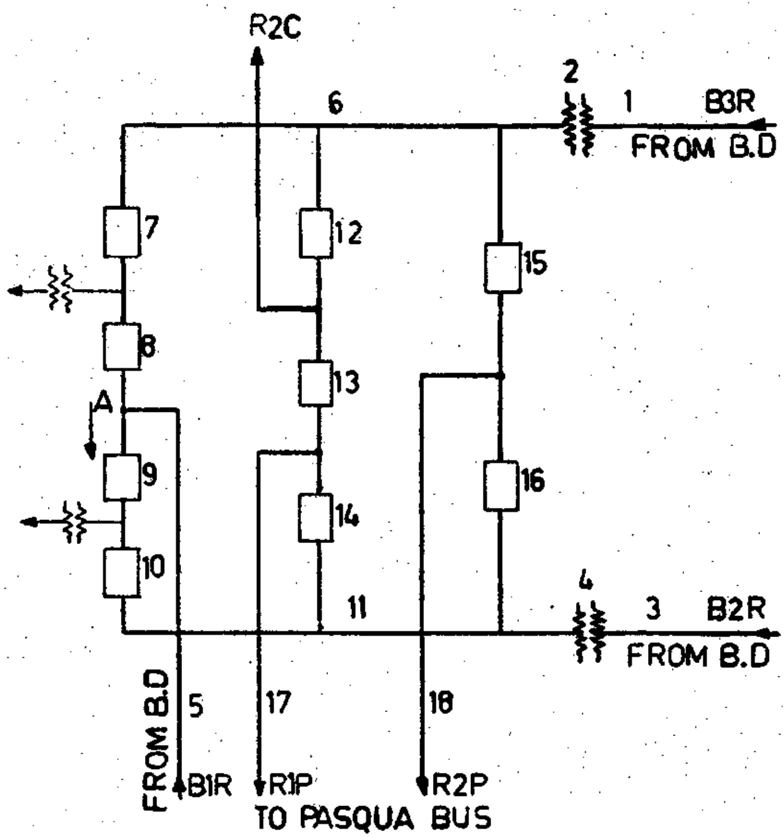


Fig. 3.14 Regina Switching Station of the Saskatchewan Power Corporation.

If the breaker active failure rate is 0.002 f/yr. and 0.007 f/yr. is its total failure rate, then with B2R normally open,

λ_{SL} = 0.000530 f/yr., r_{SL} = 2.00 hrs., $\lambda_{SL}.r_{SL}$=0.00107 hrs./yr.

If power flow at point A is in the direction opposite to that shown in Figure 3.14, then

λ_{SL} = 0.000578 f/yr., r_{SL} = 1.80 hrs., $\lambda_{SL}.r_{SL}$ = 0.001045 hrs./yr.

If power flows at point A are allowed in both directions, then

λ_{SL} = 0.000314 f/yr., r_{SL} = 1.24 hrs., $\lambda_{SL}.r_{SL}$ = 0.00039 hrs./yr.

If power flows at point A can be in any direction, then

λ_{SL} = 0.000306, r_{SL} = 1.26 hrs., $\lambda_{SL}.r_{SL}$ = 0.000386 hrs./yr.

The base cases of substation and switching station examples given, required execution times of 1.5 and 1.75 seconds respectively of C.P.U. time. It is clear, therefore, that the computer time depends not only on the number of components in the system, but also on the number of cut sets and system complexity.

The examples presented in this section clearly illustrate the principal features of the computer program. The relative economic and reliability benefits associated with various configuration changes can be evaluated in quantitative terms. This provides a useful input to the judicious selection of a particular design keeping in view the economic and reliability constraints.

3.7 Application Of The Program For The Evaluation Of Overload Outages

The computer program described in section 3.5 has been extended to consider cases where discontinuity of connection between the source and the load points is not the only failure mode. Under certain system conditions, interruptions can occur at the designated load point due to component overload outages. The program proceeds to consider this condition in the same sequence as described earlier. An additional input is provided to identify the components such as transformers, lines etc. which are liable to suffer overloads. The capabilities of these components are also provided. As the program determines the cut sets for the designated load point, a simple algorithm scans those cut sets which contain components liable to suffer overload outages. These cut sets are then evaluated for their contributions to outage indices due to component overloads using the equations described in Chapter 2.

The distribution substation shown in Figure 3.9 is used as an example to illustrate this outage aspect. The capability of transformers and lines were assumed to be 10 Mw and 20 Mw each respectively. A Saskatchewan Power Corporation substation load[8] with a peak of 13.2 Mw was assumed at the load point. Table 3.6 lists the various double contingency events and their contribution to the outage indices due to component overload outages. (The program, however, also evaluates higher order contingencies). It is assumed

TABLE 3.6

RELIABILITY INDICES DUE TO COMPONENT OVERLOADS FOR SYSTEM IN FIGURE 3.9

Failure Event	Outage Rate, f/yr	Av. Duration, Hrs.	Total Outage Time, Hrs./yr.
Disct. 6 P.F, Trans. 9 overloaded	0.107 E + 00	1.49	0.160 E + 00
Disct. 7 P.F, Trans. 8 overloaded	0.107 E + 00	1.49	0.160 E + 00
Trans. 8 P.F, Trans. 9 overloaded	0.100 E + 00	5.17	0.517 E + 00
Trans. 9 P.F, Trans. 8 overloaded	0.100 E + 00	5.17	0.517 E + 00
Bkr. 11 P.F, Trans. 8 overloaded	0.113 E - 00	1.90	0.215 E - 01
Bkr. 10 P.F, Trans. 9 overloaded	0.113 E - 01	1.90	0.215 E - 01
Bkr. 3 A.F, Trans. 9 overloaded	0.128 E - 01	1.44	0.185 E - 01
Bkr. 4 A.F, Trans. 8 overloaded	0.128 E - 01	1.44	0.185 E - 01
Total Contributions	0.438 E + 00	3.25	0.142 E + 00

that component maintenance outages will not cause any overload outages. This situation, if applicable, can also be evaluated. This is illustrated in Chapter 5.

It should be noted that the procedure for the evaluation of overload outages as described above is valid when there is only one load point in the system. When more than one load point is to be considered, the approach outlined in Chapter 5 can be used.

3.8 Summary

Valid representation of component and system behaviour requires a separation of component failure modes and their occurrence rates. In a simple radial feeder, a conductor open type failure will interrupt all customers from the open point and beyond whereas a conductor failure to ground will cause that particular circuit to trip and result in interrupting all customers from the circuit breaker or sectionalizer and beyond. In this chapter, a novel concept of component active and passive failures is introduced which permits the inclusion of all realistic component failure modes in reliability predictions. This approach is used to evaluate the reliability performance of substations and switching stations in terms of their outage frequencies and durations. A general computer program based on a cut set approach is described for reliability calculations. The algorithms are programmed to select the various possible combinations of events within the system which can cause interruption to the designated load point. The program output provides a sequential and concise description of various system contingencies and their contributions to system unreliability. Two practical system examples are presented to expose the salient features of the program. The effects of varying the component parameters, system configuration, and successful mode of system operation on reliability indices are illustrated. This form of analysis provides a quantitative basis for the judicious selection of a reliable and economic design .

4. QUANTITATIVE EVALUATION OF MAINTENANCE POLICIES IN DISTRIBUTION SYSTEMS

4.1 Introduction

As noted in the previous chapters, a considerable amount of work has been done in the field of power system reliability evaluation(1). The published literature clearly shows that little attempt has been made to optimize component and system maintenance parameters. Reference 28 describes some basic reliability and maintainability concepts applied in the area of generating station design. In the literature on transmission and distribution system reliability evaluation, preventive maintenance has always been considered as a procedure that is carried out in accordance with a policy predetermined by other considerations and thus performed with a given frequency and mean duration not subject to any changes. Interest has generally been confined to the evaluation of possible overlapping system outages due to components removed from service for preventive maintenance.

This chapter describes some basic considerations involved in the determination of consistent maintenance policies for distribution system components. It has been noted in references 17 and 29 that a major cause of double contingency outages is the occurrence of a component failure during the period when another component is out for preventive maintenance. If the maintenance outage rate of a component is reduced (in order to decrease the probability of occurrence of this kind of double contingency event), an increase in its failure rate may result. This can increase the risk of failures due to overlapping component outages. There is, therefore, a possibility of choosing some compromise between component maintenance and failure rates. This chapter investigates this possibility in order to optimize component and system reliability performance.

In many practical systems, two or more components are simultaneously taken out for preventive maintenance. This type of action is designated as performing co-ordinated maintenance on system components. If component maintenance is properly co-ordinated, considerable improvement in outage frequency and duration indices may be obtained. This chapter illustrates the quantitative benefits associated with different methods of co-ordinating component maintenance. The computer program described in Chapter 3 has been used extensively in the studies described.

4.2 Factors Influencing Preventive Maintenance Policies

Maintenance can be generally subdivided into the two general categories of corrective and preventive action. Corrective maintenance is performed when a component actually fails, while preventive maintenance is an action carried out to hopefully forestall the occurrence of future failures. In this chapter, the general expression maintenance is used to imply the latter category of preventive maintenance.

There are many considerations which can influence the level of maintenance action. Figure 4.1 illustrates the principal factors that govern the maintenance policies for transmission and distribution system components. The implications associated with different blocks shown in Figure 4.1 are as follows:

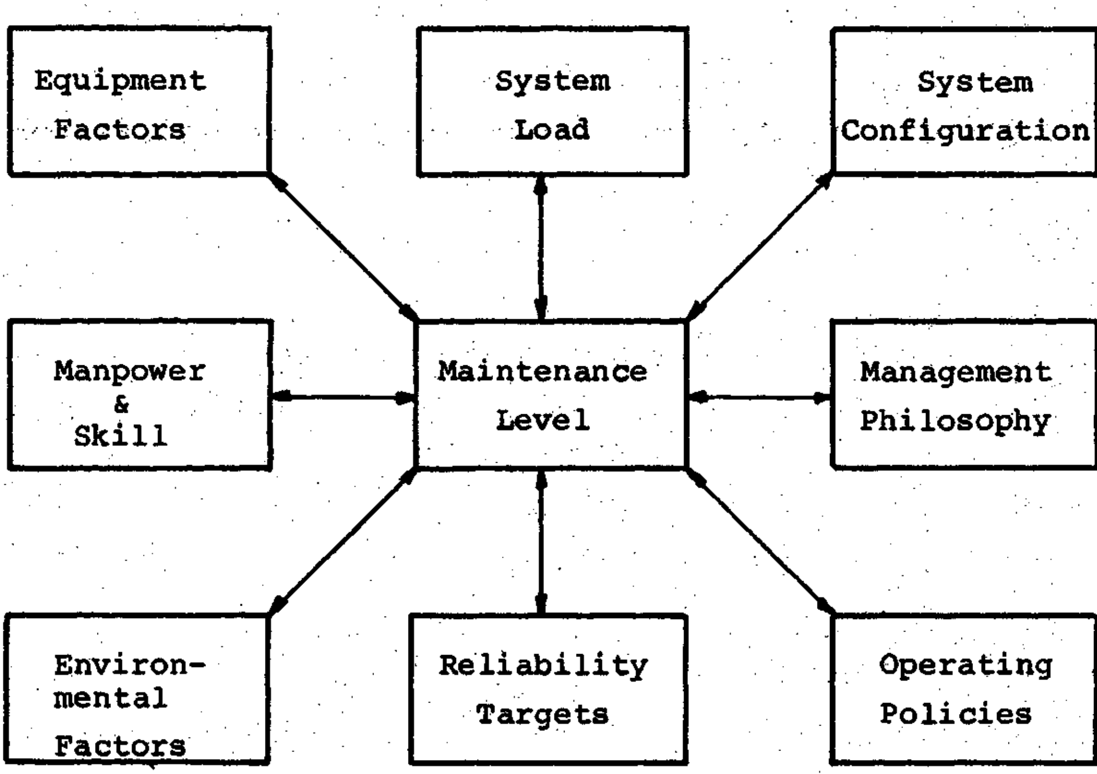


Figure 4.1 Factors Influencing Preventive Maintenance Policies

(i) The system load has a significant effect in the determination of a maintenance policy. No maintenance action will generally be started if the removal of the component will cause overloads on other components or customer interruptions. In certain cases, preventive maintenance can result in a scheduled customer outage. Maintenance will also not normally be started if the load is expected to rise to a value greater than the capability of the system components during the period of maintenance.

(ii) Equipment factors such as component type, capability, exposure etc. influence maintenance policies to a great extent. Components such as transmission lines in certain geographical areas may require a larger number of maintenance actions compared to those in other portions of the system. Increased functional action of components such as circuit breakers can lead to component failure if the maintenance level is not compatible with the action level.

(iii) The system configuration is another important factor in determining preventive maintenance policies. In a series configuration of system components, any removal of a component from service for maintenance will cause the loss of customer supply. When customers can be served from an alternate source by closing a normally open connection, component maintenance can be performed without interrupting the customers. If redundant facilities exist in the system, components can be maintained without interrupting supply to the customers.

(iv) Some maintenance activities can be performed using repair shop facilities whilst others can only be accomplished at the actual system location. The latter activity may be inhibited due to actual or predicted adverse weather conditions. In the case of overhead transmission lines, preventive maintenance is not normally done during adverse weather conditions.

(v) Management philosophy, reliability targets, availability of manpower, etc. are other interrelated factors that effect maintenance policies. All these factors have to be considered by the management in arriving at consistent maintenance policies.

It might be argued that the advantage obtained by preventive maintenance depends upon the difference between the time taken to perform maintenance and that taken to repair the component[30]. This argument may be valid in systems consisting of only a single component. This, however, is not true in power systems where a large number of components involving interacting failures are present. A component fault condition is usually much more severe than the condition existing due to a component removed from service for preventive maintenance or repair. The reliability benefits expected from a judicious selection of a particular maintenance program can be as follows:

(i) Components can be taken out of service without interrupting customer supply, which in case of failure could have caused interruption.

(ii) Component active failures[21] (ground faults etc.) can be minimized by avoiding those conditions which cause them. For example, in the case of transmission lines, active failures due to tree branches falling on them can be avoided by regular tree trimming. Similarly, in the case of oil circuit breakers, the failures of dielectric can be minimized by changing the oil at regular intervals.

(iii) System components can suffer some permanent damage due to a failure. The risk of such damage can be considerably reduced if a suitable preventive maintenance program is followed.

(iv) Preventive maintenance is a planned activity and as such the average time required for its execution can be much less than the average time required to repair a random failure.

(v) Events such as breakers becoming stuck, a normally open switch not closing when called upon to do so, etc. impose serious reliability problems. These events can cause the interruption of supply to a large number of customers. Preventive maintenance actions can considerably reduce the probabilities associated with the occurrence of these events.

(vi) Protective relaying, if maintained properly, can also reduce the probabilities associated with events described in (v).

4.3 Optimization of Component Maintenance Intervals

The failure pattern of power system components, in general, is characterized by the bath tub curve shown in Figure 4.2. The failure rate during the initial or debugging period decreases as a function of time. Failures during this period are generally due to manufacturing defects or improper design. Failures during the useful life period occur purely by chance

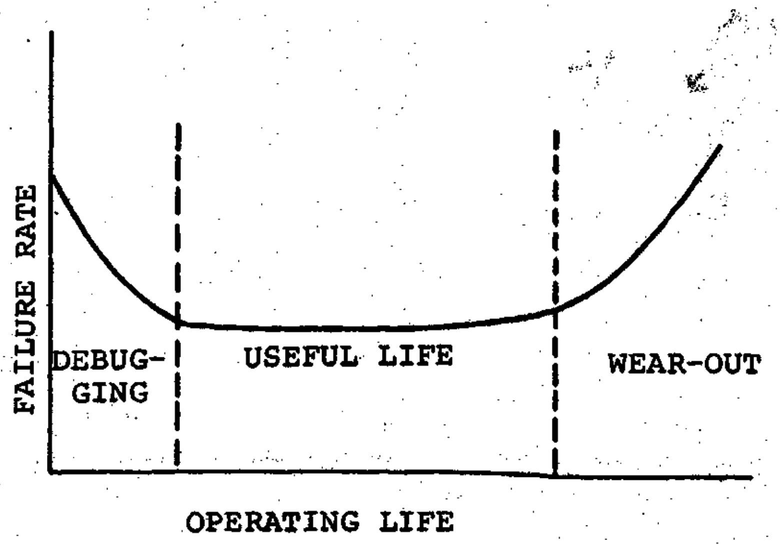


Figure 4.2 Component Failure Rate As A Function of Age

and the failure rate during this period is constant. The failure rate increases rapidly as the component enters the wearout period. The entry into the wear-out region can often be avoided and the useful life period extended by constant and careful preventive maintenance. The effectiveness of this procedure depends upon a knowledge of the time when a component starts to show deterioration. If the variability of these times is small, then preventive maintenance can be quite effective. In this case, if preventive maintenance is scheduled sooner than the average time to deterioration for the component, the entry into the wear-out region can be avoided. On the other hand, if the deterioration times have great variability, the maintenance interval would have to be relatively short in order to lengthen the useful life period.

In determining an optimal maintenance interval, it is assumed in this chapter that through component preventive maintenance, the average failure rate over the operating life of the component is reduced. The optimization procedure is dependent on the availability of a function relating the component failure rate with the maintenance outage rate. Assume that the component average failure rate and the maintenance outage rate are related by an exponential function as follows:

$$\lambda(\lambda'') = \lambda_{wp} e^{-\alpha\lambda''} \text{ for } \lambda'' \leqslant \lambda''_o \qquad (4.1)$$

where

λ_{wp} = The average failure rate of the component without preventive maintenance.

λ'' = The average maintenance rate of the component.

λ = The average failure rate of the component.

α = A constant determined by the component type and the effectiveness of preventive maintenance.

λ''_o = A value of maintenance outage rate after which the exponential relation of equation 4.1 does not hold.

The relation given by equation 4.1 is illustrated in Figure 4.3.

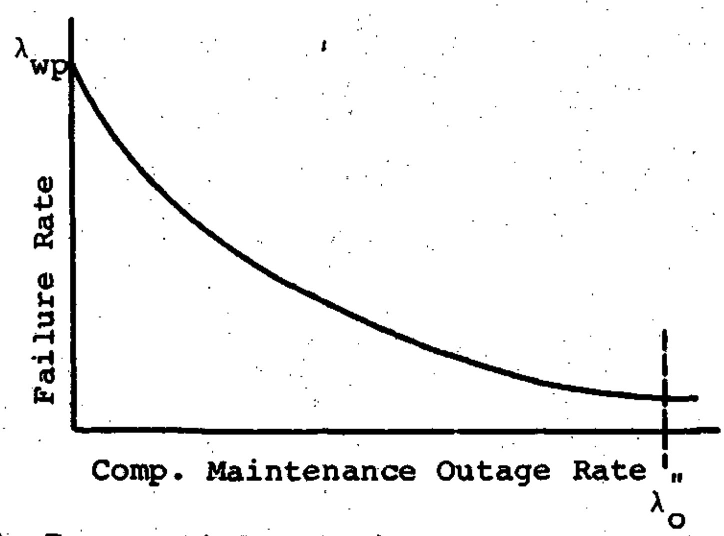


Figure 4.3 Exponential Relation of Equation 4.1.

Optimization of the maintenance outage rate can be performed considering many possible criteria. Three of these are considered in the following.

(i) Minimum component overall outage rate.

In this case,

Component overall outage rate, $\lambda_T = \lambda'' + \lambda(\lambda'')$

$$= \lambda'' + \lambda_{wp} e^{-\alpha\lambda''}$$

For λ_T to be minimum

$$\frac{d\lambda_T}{d\lambda''} = 0 \qquad (4.2)$$

Equation 4.2 yields the following optimal value of component maintenance outage rate.

$$\lambda''\text{opt.} = 1/\alpha \ln \alpha \lambda_{wp} \; ; \; \lambda'' \leqslant \lambda''_o \qquad (4.3)$$

(ii) Minimum component total outage time.

Let

r = Component average repair time.

r'' = Component average maintenance time.

Component total outage time, $T = \lambda'' r'' + \lambda r$

$$= \lambda'' r'' + \lambda_{wp} e^{-\lambda''\alpha} . r$$

For T to be minimum,

$$\frac{dT}{d\lambda''} = 0 \qquad (4.4)$$

Equation 4.4 yields the following optimal value of component maintenance outage rate.

$$\lambda''\text{opt.} = 1/\alpha \ln \frac{\alpha \lambda_{wp} r}{r''} \; ; \; \lambda'' \leqslant \lambda''_o \qquad (4.5)$$

(iii) Minimum cost of component maintenance and repair.

The costs associated with component repairs are dependent upon the average number of times the repairs are performed and the associated average outage duration. In a similar manner, the costs for maintenance action are dependent on the number of times the maintenance is performed and the associated average duration.

Let the annual costs associated with the component repair be

$$C_r = (k_1 r + k_2)\lambda$$

where

k_1 = A constant representing the cost per unit of component repair time.

k_2 = A constant representing the cost per repair action on the component.

Let the annual costs associated with the component maintenance be

$$C_m = (k_1'' r'' + k_2'')\lambda''$$

where

k_1'' = A constant representing the cost per unit of component maintenance time.

k_2'' = A constant representing the cost per maintenance action on the component.

Total costs of component repair and maintenance,

$C = C_r + C_m$.

or $\quad C = (k_1 r + k_2)\lambda + (k_1'' r'' + k_2'')\lambda''$

If equation 4.1 holds,

$$C = (k_1 r + k_2)\lambda_{wp} e^{-\alpha\lambda''} + (k_1'' r'' + k_2'')\lambda''$$

For C to be minimum

$$\frac{dC}{d\lambda''} = 0 \qquad (4.6)$$

Equation 4.6 yields the following optimal value of component maintenance outage rate.

$$\lambda'' \text{opt.} = 1/\alpha \ \ln \alpha \ \lambda_{wp} \frac{(k_1 r + k_2)}{(k_1'' r'' + k_2'')} \ ; \ \lambda'' \leq \lambda_o'' \qquad (4.7)$$

Equations 4.3, 4.5 and 4.7 will yield, depending on various parameters, different optimal values for the maintenance outage rate. It should be noted that these equations have been derived assuming the exponential relationship given in equation 4.1. Other equations will result if a different relationship exists between the component average failure rate and the maintenance outage rate. This relationship can only be obtained by collecting actual operating data on the component failure behaviour as a function of time and maintenance activity. This information is necessary in order to derive practical and useful equations for the optimization of component reliability performance.

It is to be noted that the optimization of individual component reliability parameters (i.e. outage rates and durations) does not lead to optimization of the system indices. This is illustrated by considering the example of the ring bus configuration shown in Figure 4.4. The component data for this example is given in Table 4.1[17].

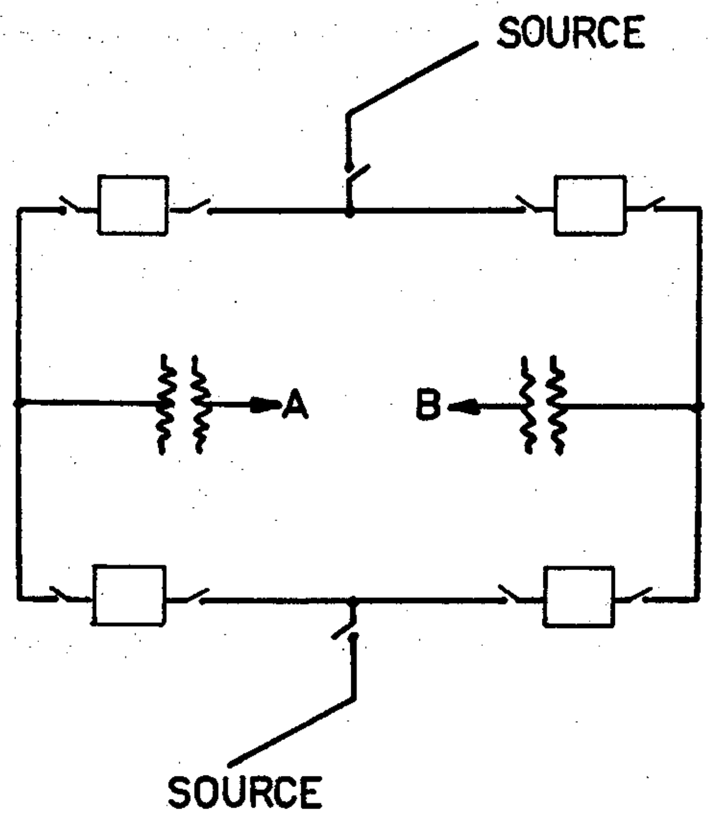


Figure 4.4 A Ring Bus Configuration

TABLE 4.1

COMPONENT PARAMETERS FOR THE SYSTEM IN FIGURE 4.4

Components	Failure Rate F/yr.	Outage Duration Hrs.	Unavailability
Circuit breaker fault	0.007	72.0	---
Maintenance	2.190	16.0	0.004
Probability of breaker found inoperative	---	---	0.0005
Transformer			
Sustained outage	0.012	168.0	---
Maintenance	2.920	12.0	0.004
Bus section			
Sustained outage	0.007	3.5	---
Maintenance	1.500	18.0	0.003
Line section			
Sustained outage	0.050	23.0	---
Maintenance	2.920	15.0	0.005

The criterion of successful system operation is assumed to be the continuity of supply to any one of the load points A and B. It has been assumed that the objective is the optimization of the line maintenance rate. Assuming $\lambda_{wp} = 4.0$ f/yr and $\alpha = 1.5$, equations 4.3 and 4.5 yield the following optimum line maintenance rate values.

From equation 4.3,

$$\lambda'' \text{opt.} = 1/1.5 \ln 6 = 1.197 \qquad (4.3a)$$

From equation 4.5,

$$\lambda'' \text{opt.} = 1/1.5 \ln 9.2 = 1.48 \qquad (4.5a)$$

Results have been obtained for the system outage rate and the total outage time using the exponential form of equation 4.1 for the line outage rate and the equations described in Chapters 2 and 3. These results are shown in

Figures 4.5 and 4.6. Following two cases were considered:

(i) Equation 4.1 is applicable for only one incoming line.

(ii) Equation 4.1 is applicable to both the incoming lines.

It is evident from Figure 4.5 that a minimum value of system outage rate is obtained at a line maintenance outage rate of 2.0 o/yr and at 4.2 o/yr for cases (i) and (ii) respectively. Equation 4.3a, however, gives a value of 1.197 o/yr for the optimum line maintenance outage rate. Similarly, from the total outage time graph shown in Figure 4.6, optimum values of 2.0 o/yr and 4.0 o/yr are obtained respectively for cases (i) and (ii). Equation 4.5a, however, gives an optimum line maintenance rate of 1.48 o/yr. This value is considerably different from that obtained from the system viewpoint. Different maintenance outage rate values from the system considerations will be obtained for different criteria of successful system operation. This clearly illustrates that for optimization of the system performance indices, a system approach to the optimization of component parameters is required.

4.4 Effects of Co-ordinating Component Maintenance

It is sometimes beneficial from the viewpoints of economics and reliability to perform co-ordinated maintenance on system components. Co-ordinated component maintenance is considered in this chapter as the policy of doing preventive maintenance on a component at a time when other maintenance or repair is being performed on an associated component.

Consider for example a series system of two components with failure rates λ_1 and λ_2 and maintenance outage

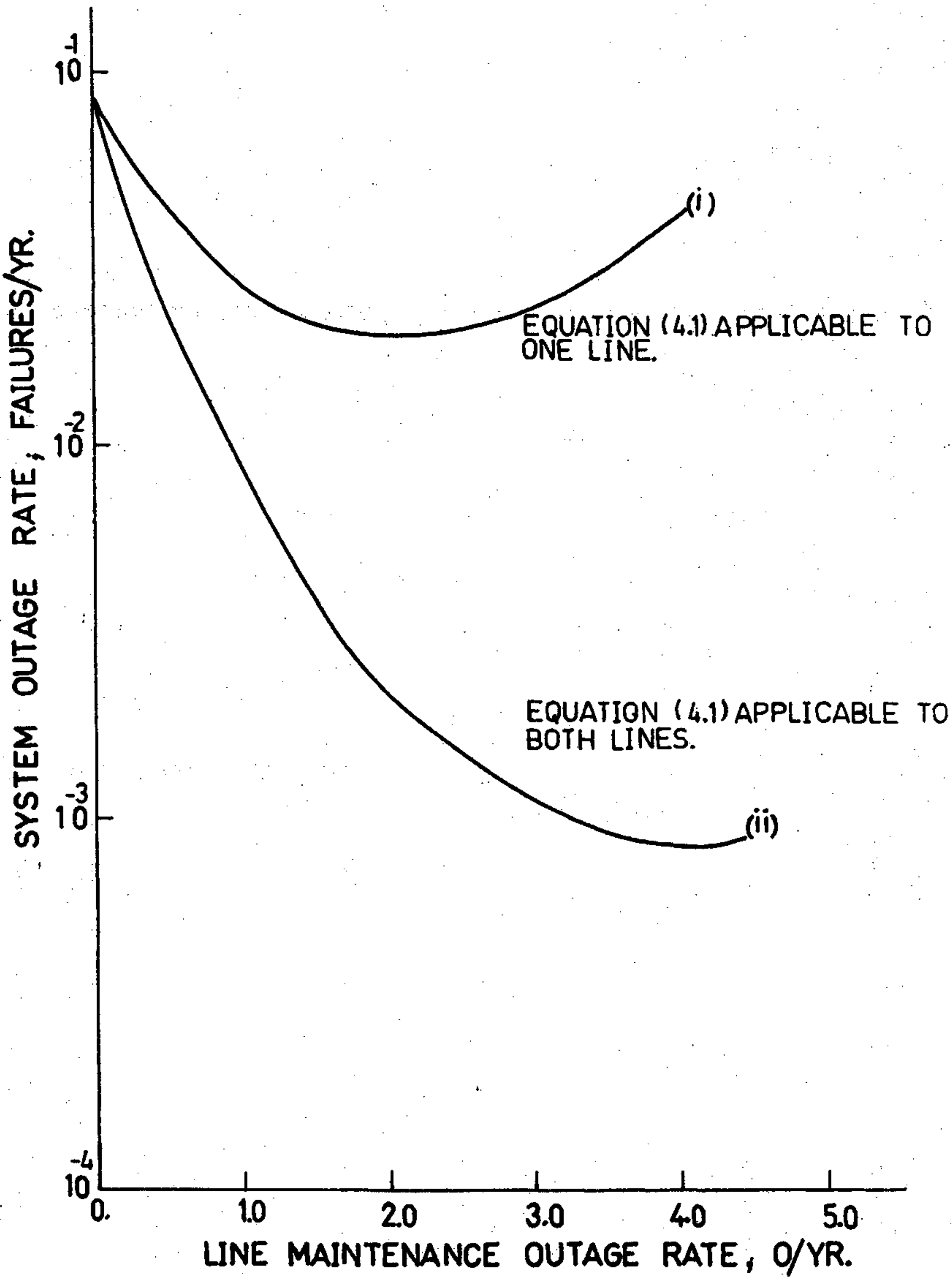


Figure 4.5 System Outage Rate as a Function of the Line Maintenance Outage Rate.

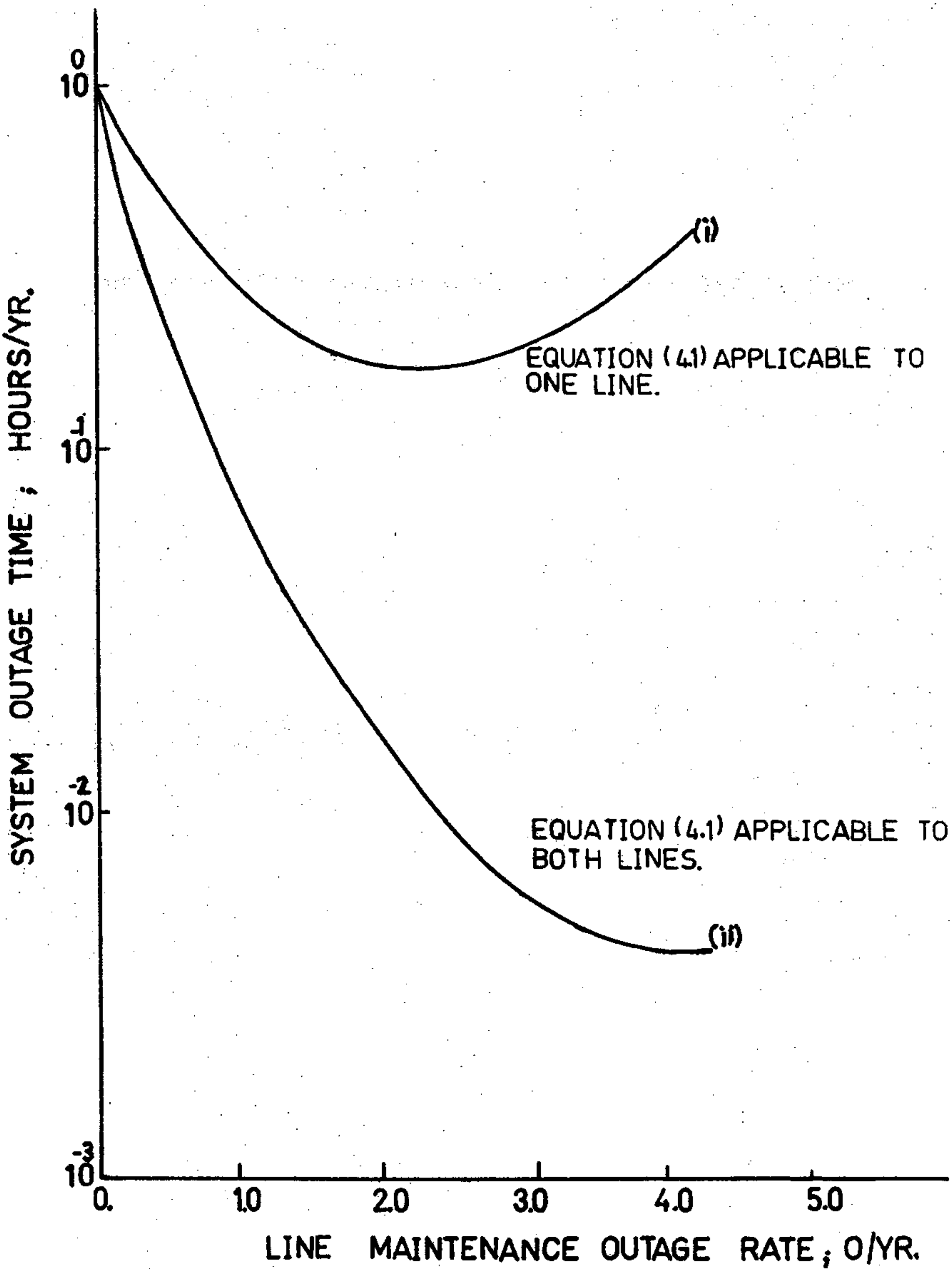


Figure 4.6 System Total Outage Time as a Function of the Line Maintenance Outage Rate.

rates of λ_1'' and λ_2''. The total outage rate of the system is given by

$$\lambda_T = \lambda_1 + \lambda_2 + \lambda_1'' + \lambda_2''$$

If, however, it is decided that component 2 will be maintained when component 1 is maintained, i.e., the maintenance of components 1 and 2 is co-ordinated, the system outage rate becomes

$$\lambda_T = \lambda_1 + \lambda_2 + \lambda_1''$$

This may represent a considerable improvement in the system outage rate.

Another possible method of improvement is to co-ordinate component maintenance and repair events. In this case, a policy might be adopted in which component 1 will be taken out for preventive maintenance when component 2 is out for repair and vice versa. The system outage rate is then

$$\lambda_T = \lambda_1 + \lambda_2$$

Considerable improvement in outage rate and duration indices can be obtained by co-ordinating component maintenance in systems involving large numbers of components. It is to be noted that co-ordinated maintenance as considered in this chapter is not performed on those components which when together removed from service will cause interruption of supply to the customer. This, in fact, implies that co-ordinated maintenance should not be performed on components which together form members of any second order cut set. Co-ordinated maintenance when performed, on two components which are present in any third order cut set can result in an increase in the risk of system outage.

The quantitative benefits associated with different methods of co-ordinating component maintenance are illustrated below for the system configuration shown in Figure 4.4. If all the components in this system are individually maintained, then the system reliability indices are as follows:

System outage rate = 0.00179 f/yr.

System average outage duration = 6.55 hours.

System total outage time = 0.01174 hours/yr.

It has been assumed in the calculation of the above indices that the system is successful if there is continuity of supply to any one of the two load points A and B. If the maintenance of the line and the line bus is co-ordinated and that of the transformer and the transformer bus is co-ordinated, the system reliability indices are as follows:

System outage rate = 0.00115 f/yr.

System average outage duration = 6.086 hours.

System total outage time = 0.0070 hours/yr.

It is, therefore, clear that this co-ordinated maintenance policy brings about a 36% decrease in system outage rate and a 41% decrease in system total outage time which is a considerable improvement in the system reliability performance.

If the breaker maintenance is also co-ordinated with that of the transformer and its bus, the system reliability indices are as follows:

System outage rate = 0.00104 f/yr.

System average outage duration = 6.637 hours.

System total outage time = 0.00689 hours/yr.

This co-ordinated maintenance policy reduces the system outage rate by 42% and the total outage time by 41.5% as compared to an unco-ordinated maintenance policy. These results clearly show that the gain obtained by co-ordinating breaker maintenance with that of transformer and its bus is very insignificant.

It should be noted that in the above considerations, it has been assumed that component maintenance durations are not increased by co-ordinating the maintenance of other components. This may not be true in many practical situations. The time out for the maintenance of a component, with which the maintenance of other components is co-ordinated, may increase considerably due to the limited amount of available manpower. The risk of component failures overlapping component maintenance periods can therefore increase to the point at which the reliability benefits of co-ordinated maintenance are completely nullified. There is therefore a limiting value up to which the average maintenance outage time of a component, with which the maintenance of other components is co-ordinated, can be allowed to increase and still justify the co-ordinated maintenance policy.

Consider, for example, a system shown in Figure 4.7

where the load is supplied through two identical transformers, each protected by breakers on h.v. and l.v. side. The con-

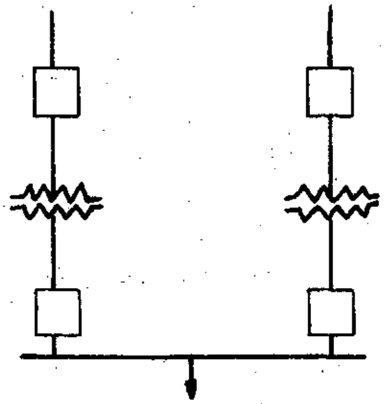


Figure 4.7 A System for Illustration of Implications Associated With a Co-ordinated Maintenance Policy.

tribution to the system outage rate due to component failures overlapping component maintenance outage periods is given by:

$$\lambda''_{ML} = 2(\lambda_1+\lambda_2+\lambda_t)\ (\lambda''_1 r''_1+\lambda''_2 r''_2+\lambda''_t r''_t) \qquad (4.8)$$

where

λ_1, λ_2 and λ_t are the failure rates of the h.v. breaker, l.v. breaker and transformer respectively.

λ''_1, λ''_2 and λ''_t are the maintenance outage rate of the h.v. breaker, l.v. breaker and transformer respectively.

r''_1, r''_2 and r''_t are the average maintenance outage times of the h.v. breaker, l.v. breaker and transformer respectively.

If, however, maintenance of the h.v. and l.v. breakers is co-ordinated with that of the transformer, and the resulting average maintenance outage time of the transformer is r'_t, then the maintenance contribution to the system failure rate is

$$\lambda''_{ML} = 2(\lambda_1 + \lambda_2 + \lambda_t)\ \lambda''_t\ r'_t \qquad (4.9)$$

In order for the co-ordinated maintenance to result in a decreased system failure rate,

$$2(\lambda_1+\lambda_2+\lambda_t)\lambda_t^{''}r_t^{'} < 2(\lambda_1+\lambda_2+\lambda_t)(\lambda_1^{''}r_1^{''}+\lambda_2^{''}r_2^{''}+\lambda_t^{''}r_t^{''})$$

or

$$r_t^{'} < (\lambda_1^{''}r_1^{''} + \lambda_2^{''}r_2^{''} + \lambda_t^{''}r_t^{''}) \;/\; \lambda_t^{''} \qquad (4.10)$$

Equation 4.10 determines the limiting value for the transformer average maintenance time. Expression similar to equation 4.10 can be written if the co-ordinated maintenance policy criterion is to reduce the system total outage time. It has been assumed in the formulation of equation 4.10 that the maintenance outage rate is greater than or equal to the breaker maintenance outage rate so that the required number of maintenance actions can be performed on the circuit breakers. If in addition to the co-ordinated maintenance with transformers, breakers are maintained separately (in order to perform the required number of maintenance actions), the following relationship for the limiting maintenance time of the transformer applies for co-ordinated maintenance to remain beneficial from a system outage rate point of view

$$r_t^{'} < \{(\lambda_1^{''}r_1^{''}+\lambda_2^{''}r_2^{''}+\lambda_t^{''}r_t^{''}) - (\lambda_1^{'}r_1^{''}+\lambda_2^{'}r_2^{''})\} \;/\; \lambda_t^{''} \qquad (4.11)$$

where $\lambda_1^{'}$ and $\lambda_2^{'}$ are the additional number of maintenance actions required to be performed on the h.v. and l.v. breakers to meet their maintenance requirements.

Similar limiting conditions can be obtained in those cases in which component maintenance is co-ordinated with repair actions on other components. This procedure of co-ordinated maintenance is called progressive maintenance[31].

The above considerations can be quantitatively illustrated for the system configuration shown in Figure 3.9. The data for this example is given in Table 3.4. The following cases were considered.

(i) The l.v. breaker maintenance is co-ordinated with transformer maintenance.

In this case, the transformer maintenance time is 48 hours. The contributions of the events involving component failures overlapping component maintenance outages to the system outage rate and the total outage time respectively with unco-ordinated maintenance are 0.0036 f/yr and 0.035 hrs/yr. It is clear from the curves shown in Figures 4.8 and 4.9 that, for co-ordinated maintenance to be beneficial, a transformer co-ordinated maintenance time of 66 hours is justifiable from the outage rate considerations and 51.5 hours from a total outage time viewpoint.

(ii) The h.v. breaker maintenance is co-ordinated with line maintenance.

In this case, the average line maintenance outage time is 8 hours. It is evident from Figures 4.8 and 4.9 that, for co-ordinated maintenance to be beneficial, a line maintenance time of 17.4 hours is justifiable from the outage rate considerations and 13.9 hours from a total outage time viewpoint.

(iii) Maintenance of the l.v. breaker is co-ordinated with transformer maintenance and that of the h.v. breaker with line maintenance.

In this case, as shown in Figure 4.8, the outage

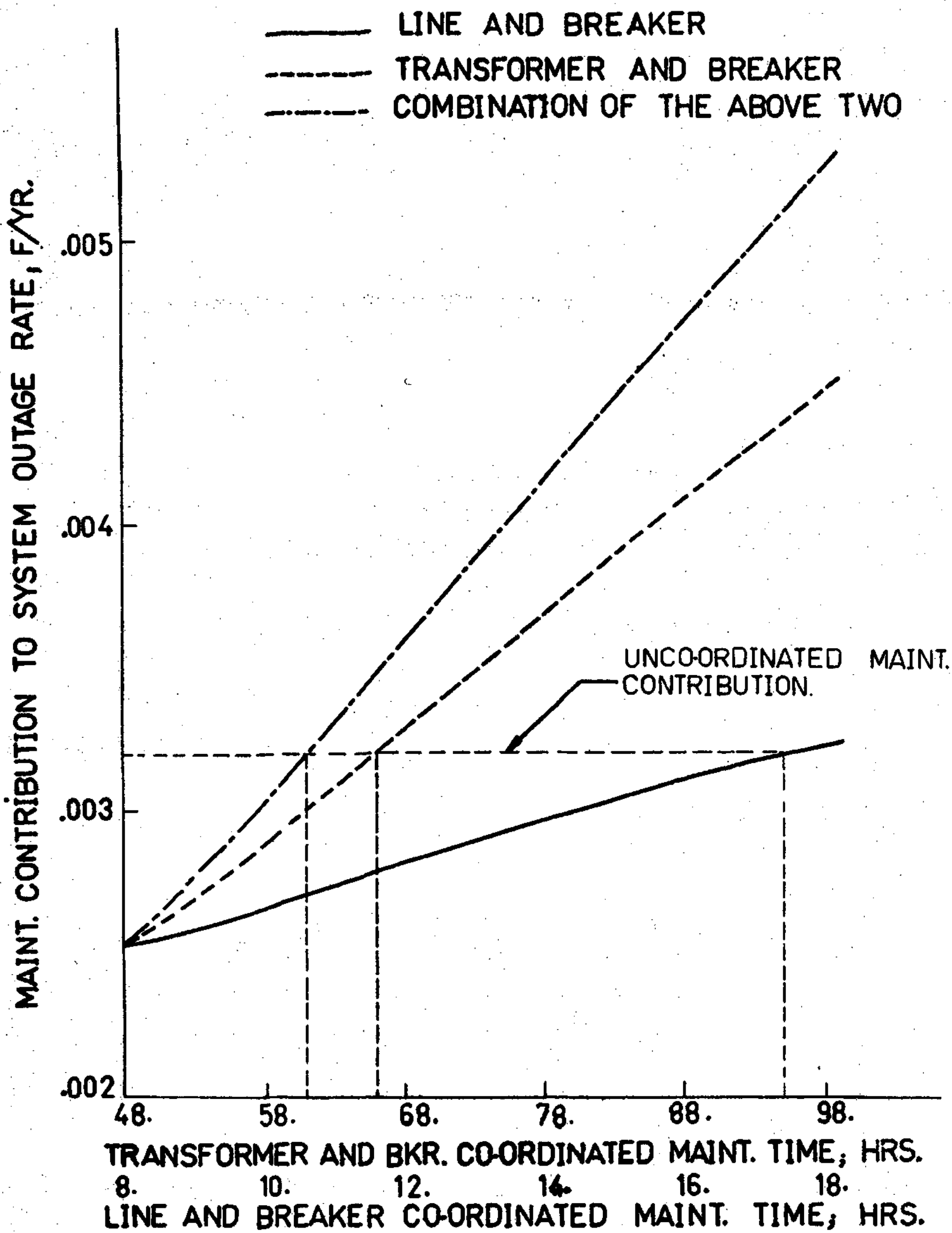


Figure 4.8 System Outage Rate as a Function of Co-ordinated Maintenance Time for Line and Breaker, and Transformer and Breaker.

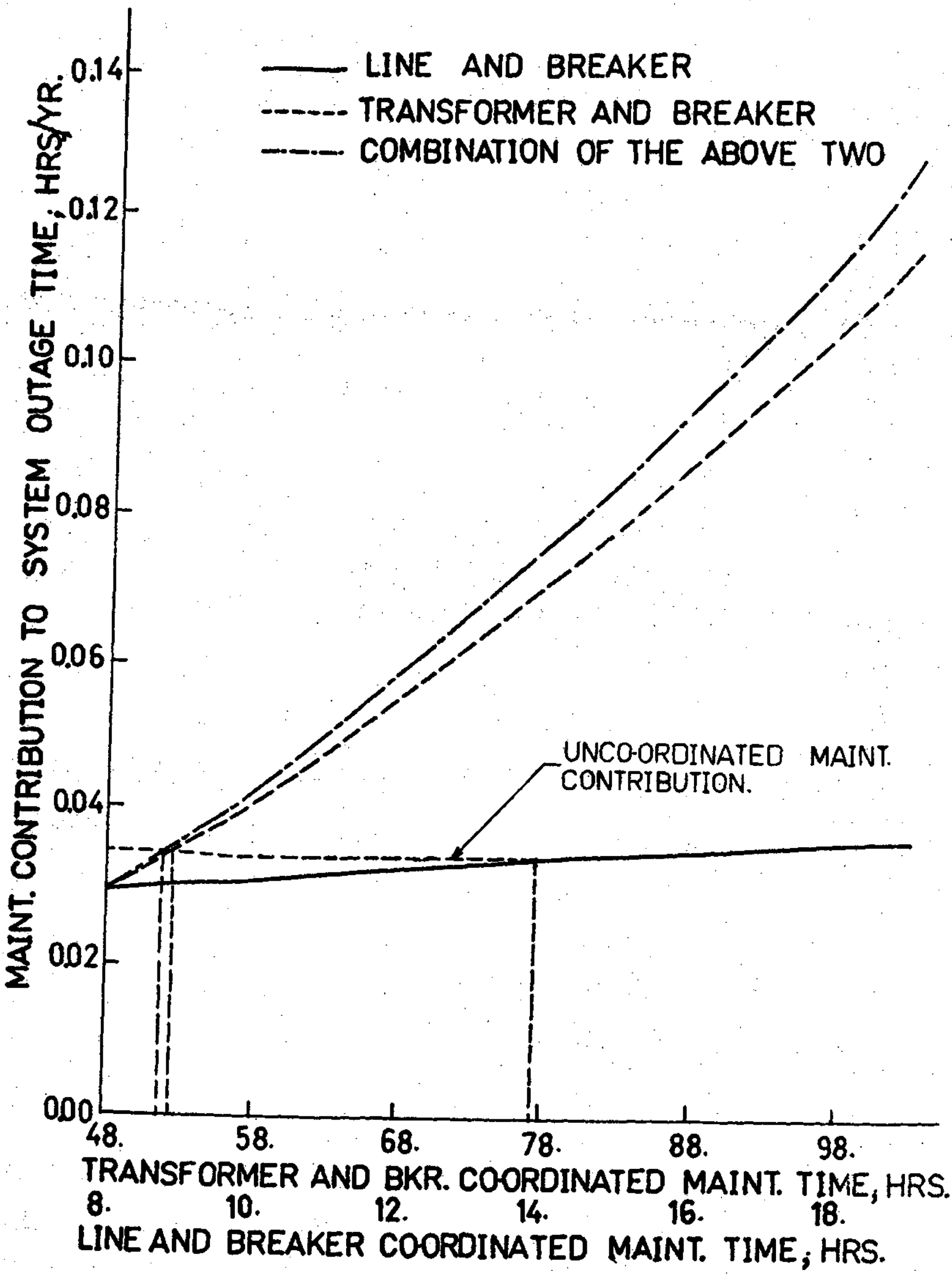


Figure 4.9 System Total Outage Time as a Function of Co-ordinated Maintenance Time for Line and Breaker, and Transformer and Breaker.

rate considerations justify co-ordinated maintenance times of 61.0 hours and 10.6 hours respectively for the transformer and the line. Similarly, from Figure 4.9, the total outage time considerations justify maintenance times of 50.7 hours and 8.7 hours respectively for the transformer and the line.

(iv) Maintenance of the l.v. breaker is co-ordinated with repair of the transformer and maintenance of the h.v. breaker is co-ordinated with repair of the line.

In this case, the outage data has been modified to suit the maintenance requirements of the breakers. The transformer repair time is changed to 168 hours. It is clear from Figure 4.10 that justifiable line and transformer average repair time with this co-ordinated policy, from total outage time considerations are respectively 7.83 hours and 170.5 hours.

It is, therefore, evident from the studies given above that a component co-ordinated maintenance policy cannot be determined solely by qualitative considerations. The quantitative evaluation of various alternative policies can assist in the judicious selection of a particular policy.

4.5 Other Maintenance Considerations

One significant cause of system unreliability is the presence of stuck breakers in the system. A stuck breaker represents a severe failure condition as it requires the operation of higher levels of system protection, thereby possibly interrupting a large number of customers. The

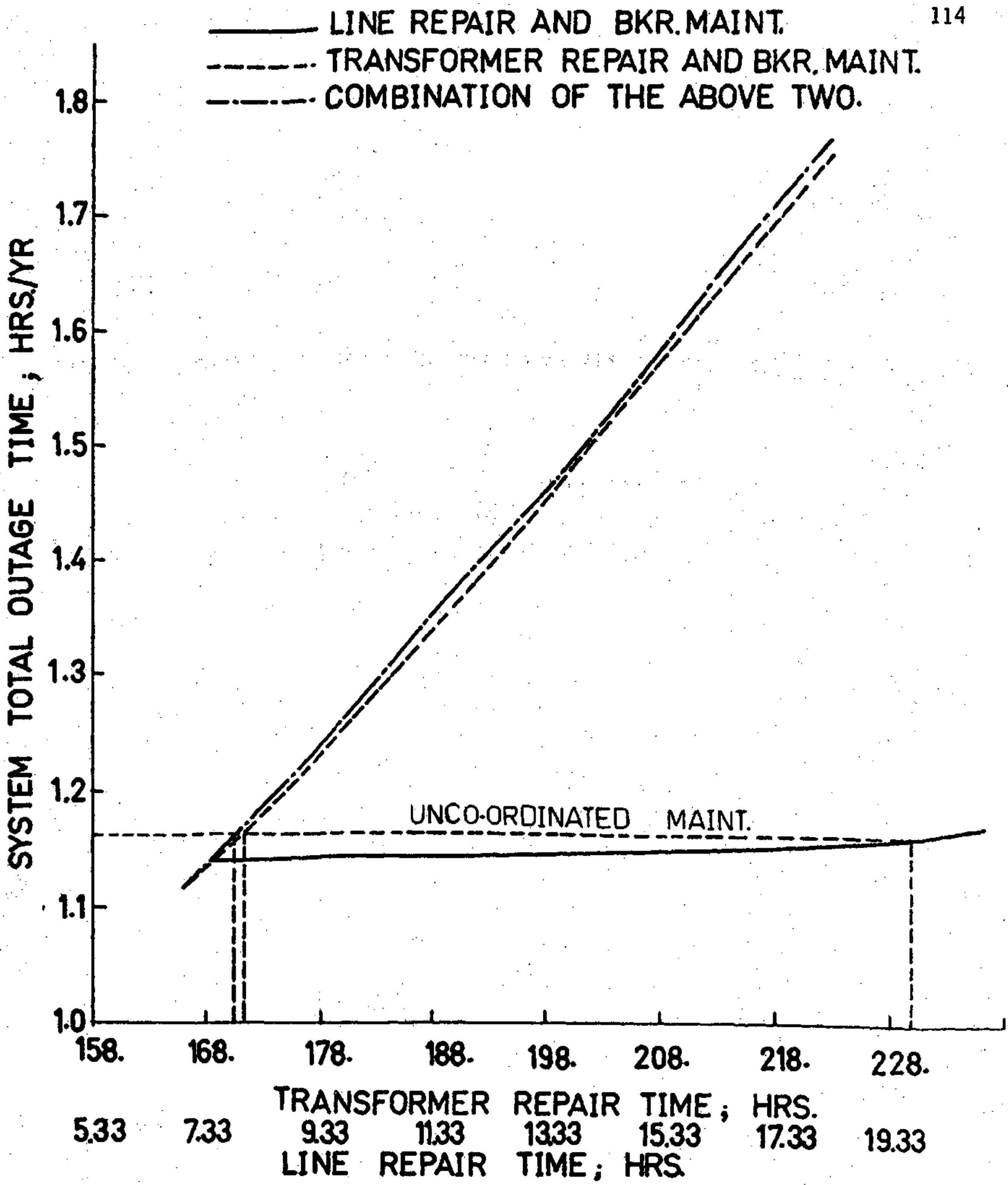


Figure 4.10 System Total Outage Time as a Function of Transformer and Line Repair Times.

probability of a breaker becoming stuck can be decreased to some extent by increasing the breaker maintenance rate. This is shown in Appendix D. If the breaker maintenance rate is increased (to decrease the probability of becoming stuck), the risk of other component outages overlapping the maintenance periods increases. There is thus an optimum value of breaker maintenance rate for which the system outage rate is a minimum. For the purpose of illustration, assume that the stuck breaker probability is inversely proportional to the breaker maintenance rate.

Let

The probability of a l.v. breaker becoming stuck

$$= \frac{0.0300}{\lambda''}$$

The probability of a h.v. breaker becoming stuck

$$= \frac{0.0025}{\lambda''}$$

Assuming the maintenance outage rate for the l.v. and h.v. breakers to be the same and other failure parameters unchanged (there can be some decrease in breaker failure rate because of increased maintenance frequency), the outage rate of the system shown in Figure 3.9 is plotted against the breaker maintenance rate in Figure 4.11. It is evident from the curve shown that a minimum system outage rate is obtained for a breaker maintenance rate of 2.0 o/yr. These considerations are therefore quite important in any optimization of breaker maintenance parameters.

Another practical consideration in the selection of

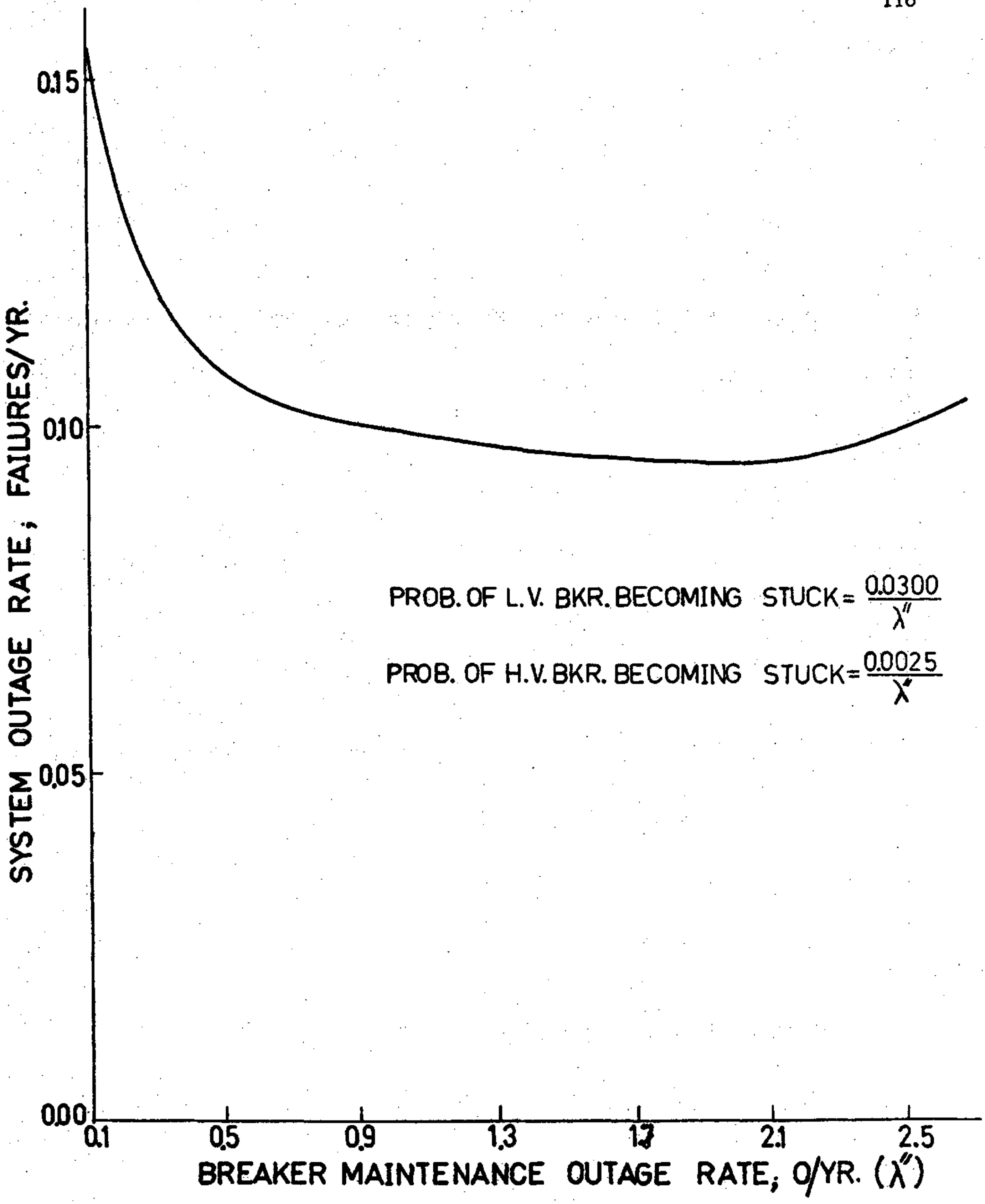


Figure 4.11 System Outage Rate as a Function of the Breaker Maintenance Outage Rate (With Varying Stuck Breaker Probabilities).

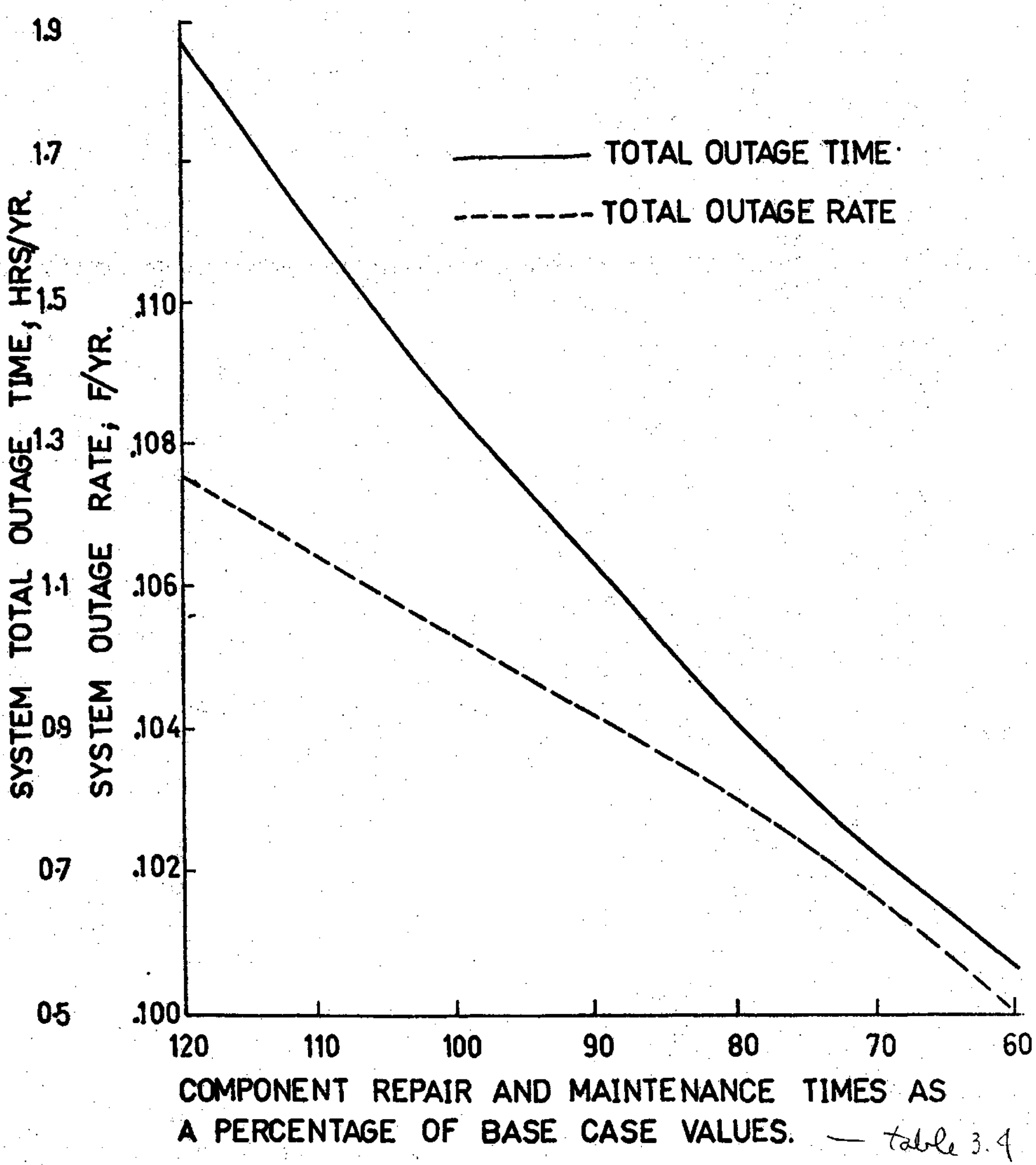


Figure 4.12 Effect on System Outage Rate and Total Outage Time of Varying Repair and Maintenance Times (Due to Variation in Manpower Available).

a maintenance policy is the amount of manpower and skill available. It has been noted from the published material on component outage statistics that component average repair and maintenance times as reported by larger utilities are smaller than those reported by smaller ones. This, probably, is due to the large manpower and facilities available in larger utilities. Figure 4.12 shows the effect of percentage reduction in component repair and maintenance times (as a result of increasing skill and manpower available) on outage rate and total outage time of the system shown in Figure 3.9. If some approximate relationship between the component repair times and available crew size can be established, then the form of analysis described above can be quite useful in logically determining the optimum size of the repair crew to achieve a predetermined reliability target.

4.6 Summary

There are many factors which should be considered in determining a suitable maintenance policy in transmission and distribution systems. Equipment factors, system configuration, system load, system environments, reliability targets, management policies etc. are some of the important considerations in the selection of an acceptable policy. This chapter has described three different criteria for the optimization of component reliability parameters. It has been shown that the optimization of individual component parameters does not necessarily lead to the optimization of system indices. The component parameter optimization procedure requires the development of functional relationships between component maintenance and failure parameters. This chapter emphasizes the need for the establishment of these relationships.

A considerable improvement in the system reliability performance can be obtained by properly co-ordinating the component maintenance. This chapter has investigated various co-ordinated maintenance policies in relation to practical systems. The quantitative benefits associated with these policies are evaluated. This analysis shows that improper co-ordination of component maintenance may lead to degraded system reliability performance. The techniques presented can be used to optimize reliability parameters of circuit breakers.

The available manpower and skill can significantly influence the component repair and maintenance times. The effect on the system outage indices of the reduction in outage times due to increased manpower available is illustrated in this chapter. This analysis can, therefore, aid in the optimization of crew size.

5. QUANTITATIVE EVALUATION OF OVERLOAD OUTAGES IN SUBSTATION AND SUBTRANSMISSION SYSTEMS

5.1 Introduction

In the previous chapters, the bulk of the studies described considered the discontinuity of supply between the source and the load points as the only criterion of failure. This approach assumes that every component in a parallel system is capable of carrying the highest load to which it may be subjected in any contingency. Power system networks are not designed considering unlimited component capabilities because of economic reasons. Even when there is continuity of connection between the source and the load points, there can be a finite conditional probability of interruption due to the removal of overloaded components by system protection. This probability value depends upon the network configuration, the system load, the component capabilities and the durations of the contingencies causing the overload.

The first step in the quantitative evaluation of frequency and duration of interruptions due to overload outages is to determine the probability that the system components will not be able to carry a given contingency load. In this chapter, some of the techniques[3,32,33,34,35] available for the estimation of this probability value are reviewed. The effects on outage indices of two different service restoration procedures after the overload outages have occurred, are illustrated. Two additional measures of interrupted load and energy are introduced to estimate the severity of overloads. The cut set approach[21] is extended to evaluate the frequencies and durations of interruptions due to overload outages in systems involving more than one load point. The application of outage indices in substation expansion planning studies is also illustrated.

5.2 A Review of the Available Methods

Many techniques have been suggested in the existing literature for the evaluation of frequency and duration of interruptions due to component overloads. All these methods are based on the convolution of the system load with the component outage model.

A method based on contingency curves was suggested in reference 3 to determine the probability of component overloads. In this method, assuming that a contingency is equally likely to occur at any time and that component capability is constant, the probability of not carrying a contingency load for a given time period is found by randomly sampling the appropriate load cycle. A set of curves representing the probabilities of failing to carry the contingency loads for various durations of contingencies and component capabilities are obtained. In a system of two parallel components, the rate of interruptions due to component overload outages is then determined from the following relationship[3].

$$\lambda_{oL} = \lambda_1 P_1 + \lambda_2 P_2 \qquad (5.1)$$

where

λ_i = The outage rate of component i.

P_i = The probability that component i will not be able to carry the contingency load.

The values of P_1 and P_2 are estimated from the contingency curves for the given component capabilities and the distribution of contingency durations. This approach was used in reference 32 to evaluate the reliability of transmission supply to substations. A further extension of this approach was made for generating capacity reliability studies [33]. The probabilities of successfully carrying the contingency loads were calculated by sampling the system load model for the given capabilities and the expected contingency durations. In this approach, the period during which overload outages can occur during a contingency state j is given by [33,36]

$$\Sigma_{n=1}^{k} (R_j + t_n)$$

where

R_j = The expected duration of contingency state j.

t_n = The duration of load level exceeding the capability available under state j.

k = The number of times the load rises above the available capability.

The probability of encountering an overload condition in a period D is then given by

$$(1 - Q_j) = \frac{1}{D} \Sigma_{n=1}^{k} (R_j+t_n) \qquad (5.2)$$

The frequency of encountering an overload condition is [36]

$$\Sigma_j F_j \ (1-Q_j) \tag{5.3}$$

where F_j is the frequency of contingency state j.

The probability of overload, $(1-Q_j)$, includes also the contribution of those contingencies which start in low load periods and extend into high load periods. It should be noted that equation 5.2 is valid as long as the contingency durations do not exceed the durations of low load periods. The equations for the frequency and duration of interruptions due to component overload outages given in references 33 and 36 are valid only when low load durations are larger than the contingency durations. The next section of this chapter, illustrates the effects of this assumption on the overload indices.

It was noted in reference 36 that equation 5.3 overestimates the frequency of encountering the overload conditions because it includes the transitions amongst the states involving overloads. This error, however, can be eliminated by evaluating the frequency of overload condition under a contingency state j separately and then combining the results with other states according to the rules of forming cumulative states[27].

Reference 34 illustrated a conditional probability approach to evaluate the probability and frequency of overload in composite systems. The probability P_L and frequency F_L of encountering overload condition, in this method, is given by:

$$P_L = \Sigma_j P_j PL_j \tag{5.4}$$

$$F_L = \Sigma_j F_j PL_j \qquad (5.5)$$

where

P_j = The probability of jth contingency state.

PL_j = The conditional probability of load exceeding the capability of contingency state j.

Equations 5.4 and 5.5 underestimate the probability and frequency indices as they do not account for system contingency states which start in low load periods and extend into high load periods. This error has been eliminated by extending the conditional probability approach[36]. The system load is represented as a stationary Markov process. The system daily load is assumed to consist of a peak load period which exists for some time and a low load level which exists for the remainder of the day. This method considers a few load levels but recognizes the effect of load and contingency durations accurately.

A two state load model was described in reference 29. In this model, the system load is considered to fluctuate between two levels. One level corresponds to load values greater then the capability of the contingency state designated as high load and the other corresponds to load values less than the capability of the contingency state designated as low load. This model assigns frequency and duration to every load level corresponding to the carrying capabilities of the various contingency states. The application of this model was illustrated by considering weather associated component failures for systems involving only one load point[8,10]. This chapter employs the two state load model to quantitatively evaluate frequency and duration of interruptions due to component overload outages.

5.3 Effects on Overload Outage Indices of Different Service Restoration Procedures

The contribution to the frequency of encountering an overload condition due to component 1 becoming overloaded when component 2 is failed, for a two component parallel system is given by,

$$\lambda_{oL} = \lambda_2 Pr\ (\ell(t) > L_1) + \lambda_L\ (1-Pr(\ell(t) > L_1))\lambda_2 r_2 \qquad (5.6)$$

where

λ_2 = The sustained outage rate of component 2.

λ_L = The rate of transition from a load level less than L_1 to a level greater than L_1.

L_1 = The capability of component 1.

r_2 = The expected repair time of component 2.

$Pr(\ell(t)>L_1)$ = The probability that the load at time t is greater than the capability of component 1.

In systems involving more than two parallel components, equation 5.6 can be generalized as follows:

$$\lambda_{oL} = \lambda_{SL}\ Pr(\ell(t) > L)+\lambda_L(1-Pr(\ell(t) > L))\lambda_{SL} r_{SL} \qquad (5.7)$$

where

λ_{SL} = The overlapping outage rate of components causing the contingency.

L = The capability of the remaining components.

r_{SL} = The average overlapping time of components causing the contingency.

Equations 5.6 and 5.7 can be interpreted in a very interesting way. The first term on the right hand side of these equations represents the contribution to the rate of encountering the overload state due to the contingency resulting in overload occurring in a high load period. The second term represents the contribution to the rate of encountering the overload state due to the contingency occurring in a low load period and extending into a high load period before the repair on the components causing the contingency is completed.

The average duration associated with λ_{oL} is given by:

$$r_{oL} = \frac{r_{SL} \cdot r_L}{r_{SL} + r_L} \qquad (5.8)$$

where r_L is the average duration of a high load period. Equations 5.7 and 5.8 for the rate and duration of system overload condition consider that the durations of low load periods, $1/\lambda_L$, are larger than the durations of the contingency. If, however, the low load duration is less than the duration of the contingency, the following two situations, after the overload outage has occurred, are possible.

(i) The service is restored as soon as the high load period is over, no matter whether the components causing the contingency are restored to service or not.

(ii) The service is not restored if the time required to repair the components causing the contingency is expected to extend into another period of high load. In this case, equations 5.7 and 5.8 are modified as follows:

$$\lambda_{oL} = \lambda_{SL} \tag{5.9}$$

$$r_{oL} = r_{SL} \tag{5.10}$$

The frequency and duration of interruptions due to component overload outages are obtained for the simple substation configuration shown in Figûre 3.9 by considering the above methods of service restoration. The component capabilities and the associated failure and repair data used in this study are given in Table 5.1.

TABLE 5.1

COMPONENT DATA USED IN OVERLOAD OUTAGE STUDIES

Component	Failure Rate F/yr	Repair Time Hrs.	Capability Mw
Transmission Lines	0.010	15.0	20
Transformers	0.012	30.0	15
Breakers (total)	0.007	10.0	--

Breakers also have a ground fault rate of 0.002 f/yr. with switching time = 1.0 hour.

Disconnects are assumed to be completely reliable.

A Saskatchewan Power Corporation substation chronological load curve[8] with a peak of 13.2 Mw was considered to exist at the substation bus. The results for the average rate and duration of interruptions at the substation bus as obtained from equations 5.7, 5.8, 5.9 and 5.10 are given in Table 5.2 for different values of bus peak load. It is clear that the rates of interruption due to component overload outages associated with service restoration procedure (i) are

TABLE 5.2

INTERRUPTION RATE AND DURATION INDICES DUE TO COMPONENT OVERLOAD OUTAGES

Peak Load	Service Restoration Procedure (i)			Service Restoration Procedure (ii)		
	Rate f/yr	Duration Hrs.	Total Outage Time Hrs./Yr.	Rate f/yr	Duration Hrs.	Total Outage Time Hrs./Yr.
13.20	---	---	---	---	---	---
14.52	---	---	---	---	---	---
15.97	0.02176	1.183	0.02574	0.02176	1.183	0.02574
17.57	0.05066	1.827	0.09255	0.03362	21.879	0.73560
19.33	0.06866	3.665	0.25170	0.03865	19.720	0.76220
21.26	0.06847	5.588	0.40316	0.04286	18.420	0.78960
23.38	0.10368	5.455	0.56570	0.06779	13.418	0.90970
25.72	0.10554	7.247	0.76492	0.07434	16.193	1.20380
28.30	0.09755	10.043	0.97970	0.07567	16.236	1.22850
31.13	0.08856	12.710	1.12540	0.07600	17.158	1.30400

higher than those associated with service restoration procedure (ii). The average duration index associated with procedure (i) is, however, smaller than that associated with procedure (ii). The total outage time resulting from service restoration procedure (i) is always less than or equal to that due to service restoration procedure (ii). The sudden increase in the rate index at the peak load of 21.26 Mw is attributed to line failures which begin to make a contribution to overloads at this load level.

5.4 Evaluation of Interruptions Due to Component Maintenance Outages Extending Into High Load Periods.

Component maintenance outages depend on the load fluctuations. In general, components will not be taken out for maintenance if such an action results in overload of other components. This implies that no maintenance activity will be started in a high load period. It is, however, possible that a maintenance outage starting in a low load period extends into a high load period and causes overload outages of other components. If overloaded components are tripped out of service by the system protection, the interruptions occurring due to this mode of component failure can be evaluated by considering equations 5.6 and 5.7. As noted in section 5.3, the first term on the right hand side of equation 5.7 gives the contribution to the system interruption rate due to component outages starting in high load period. Since no maintenance will be performed in those periods where overloads may occur, this term is zero for component maintenance outages. The second term in equation 5.7 gives the contribution to the interruption rate when a contingency starts in a low load period but the load transits to a high value before the contingency is over. The contribution to system interruption rate due to component 1 becoming overloaded when component 2 is out for maintenance, for a two component parallel system, is therefore given by:

$$\lambda_{oL} = \lambda_L \;(1-Pr(\ell(t) > L)\lambda_2''r_2'' \qquad (5.11)$$

where

λ_2'' = The maintenance outage rate of component 2.

r_2'' = The average maintenance outage time of component 2.

The average duration associated with λ_{oL} is given by:

$$r_{oL} = \frac{r_2''r_L}{r_2''+r_L} \qquad (5.12)$$

It should be noted that in the formulation of equation 5.9, it is assumed that a maintenance outage is started in a low load period (so that no other system component is overloaded) without any knowledge of the load in the immediate future. This is not true if loads are highly predictable in nature. In such instances, equation 5.9 provides a pessimistic estimate of the interruption rate due to component overload outages.

Using equations 5.11 and 5.12, interruption rate and duration indices due to component overload outages have been obtained for the substation configuration shown in Figure 3.9. The data shown in Table 5.1 and 5.3 are used for this study. The results obtained are given in Table 5.4. It is clear from this table and Table 5.2 that, for the data assumed, the contribution to interruption indices due to events involving component maintenance and overload outages increases as the system load increases and this contribution is larger than that resulting due to events involving component sustained and overload outages.

TABLE 5.3

COMPONENT MAINTENANCE DATA

Component	Maintenance Rate, o/yr.	Average Maint. Duration, Hrs.
Transmission Lines	0.25	7.0
Transformers	0.25	10.0
Breakers	1.00	5.0

TABLE 5.4

INTERRUPTION INDICES DUE TO EVENTS INVOLVING COMPONENT MAINTENANCE AND OVERLOAD OUTAGES

Peak Load	Interruption Rate, f/yr.	Average Duration, Hrs.	Total Outage Time, Hrs./Yr.
13.20	---	---	---
14.52	---	---	---
15.97	0.3562	1.037	0.3694
17.57	0.8014	1.508	1.2084
19.33	0.9794	2.598	2.5444
21.26	1.0753	3.466	3.7259
23.38	1.4246	2.976	4.2400

5.5 Load Related Indices

In all the previous models considered, it was assumed that the system components are removed by the system protection if the load exceeds their carrying capabilities. The component carrying capabilities are considered to be constant. In many cases, components may be called upon to carry loads greater than their capabilities even at the risk of loss of life. In such cases, system planners may be interested in determining the expected amount of overload experienced by system components. This value when used in conjunction with frequency and duration of states involving overloads can be related to the expected loss of component life during a specified period of time.

It is clear from Table 5.2 that frequency and duration indices do not provide any information on the expected amount of load and energy interrupted if overloaded components are removed from service by the system protection. This information can be quite useful to system planners in comparing alternative configurations.

These load related indices can be evaluated from the two state load model without any significant increase in attendant computational time. As the frequency and duration indices associated with a particular load level are evaluated, the amount by which the load exceeds the carrying capability is also computed. The average of these values gives the extent of overload experienced by the overloaded components. The expected value of overload experienced by a component is then the weighted average of the overload values in the different contingency states using the probability of being in those states as the weighting factor. If in a particular state two or more components are overloaded, the amount of overload is divided in the ratio of their capabilities. The amount of load and energy interrupted at a bus, if overloaded components are removed from service, are similarly obtained. These indices have been calculated for the substation example considered in the previous sections. The results are shown in Table 5.5.

TABLE 5.5

LOAD RELATED INDICES FOR SYSTEM IN FIGURE 3.9

Peak Load	Expected Amount Of Overload - Mw		Load Interrupted - Mw	Energy Interrupted-Mwhr.
	Transformer	Lines		
13.20	---	---	---	---
14.52	---	---	---	---
15.97	0.1976	---	15.1976	0.3912
17.57	1.0830	---	16.0830	1.4885
19.33	1.4278	---	16.4277	4.1345
21.26	2.2655	1.2587	17.2912	6.9711
23.38	3.2737	1.4063	18.5337	10.4843
25.72	4.2954	1.8654	19.7256	15.0885
28.30	5.2533	2.9803	20.8208	20.3990
31.13	6.6548	4.3218	22.2806	25.0760

It is assumed in calculating the energy index that the components are restored to service as soon as the high load period is over. Table 5.5 clearly shows that the load related indices are relatively more sensitive to load values than the frequency and duration indices.

5.6 Expansion Planning in Substations

A substation normally serves an area which can be defined in some geographical form. The area load increases with the growth of customer demands. This growth process results in an increased risk of overloading transformers and other associated equipment under normal and contingency conditions if no area and station modifications are made. The risk of interruptions due to component overload outages can be held below a certain acceptable value by any of the following alternatives:

(i) The existing station facilities are allowed to carry loads greater than their capabilities thus accepting a risk of reduced useful equipment life.

(ii) The existing station components are replaced by higher capability components. If possible, new facilities can also be provided. This method of decreasing the risk has an associated penalty of additional investment.

(iii) New stations are provided in the area to share loads with the existing ones. This method also involves additional investment.

The problem is to develop a substation loading and expansion plan which will provide an acceptable level of service reliability at the lowest possible cost. It is quite difficult to choose a single comprehensive index which defines system reliability and a resulting acceptable level.

If it is assumed that the overloaded components are tripped out of service by the system protection, the interruption frequency and duration due to component overload outages can be quite useful indices in substation expansion planning. This is illustrated by considering the substation configuration shown in Figure 3.9. It has been assumed that both peak and off peak demands grow by 10% every year. A Saskatchewan Power Corporation load with a peak value of 13.2 Mw was considered to exist at the sub-station bus in the first year and the transformer capabilities were assumed to be 10 MVA each. The interruption rate and total duration indices due to component overload outages were obtained through the years of expansion planning by using equations 5.7 and 5.8. It was further assumed that with all the system components in service, no overloading is allowed to occur. The acceptable levels of interruption frequency and total interruption time due to component over-load outages were arbitrarily selected at 0.04 f/yr and 0.2 hrs/yr. One of the many possible expansion alternatives is considered below.

(i) Replace one 10 Mw capability transformer by one with 20 Mw carrying capability.

(ii) Replace the remaining 10 Mw capability transformer with another 20 Mw transformer.

(iii) Provide a new 40 Mw capability substation to share the area load.

The interruption frequency and duration indices as obtained for this expansion alternative are shown in Figures 5.1 and 5.2. The acceptable interruption rate index requires that step (i) of expansion be carried out in year 2, step (ii) in year 6 and step (iii) in year 7. In this case it may, therefore, be advisable to go from step (i) to step

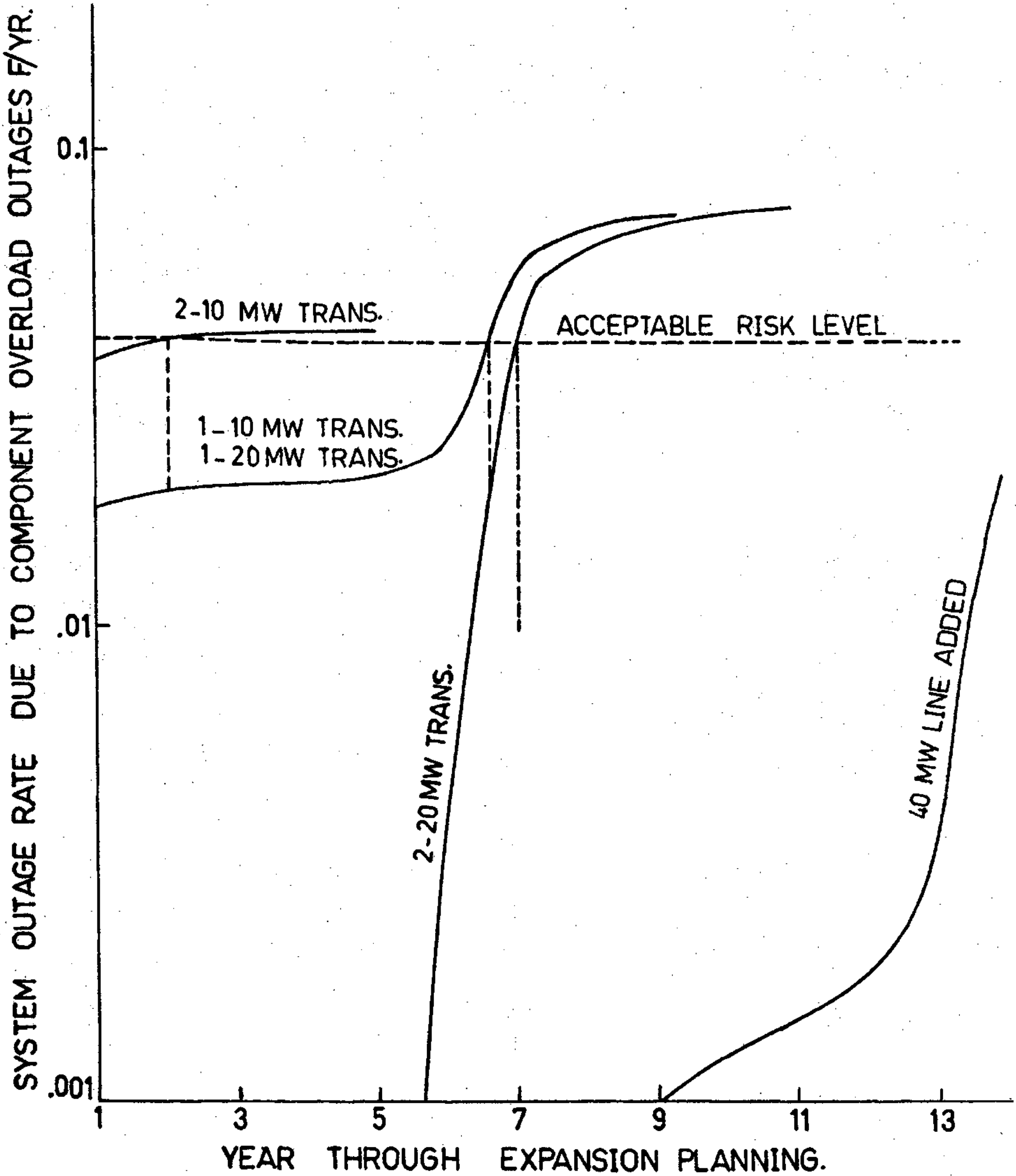


Figure 5.1 System Outage Rate Due To Component Overload Outages as a Criterion of Substation Expansion Planning.

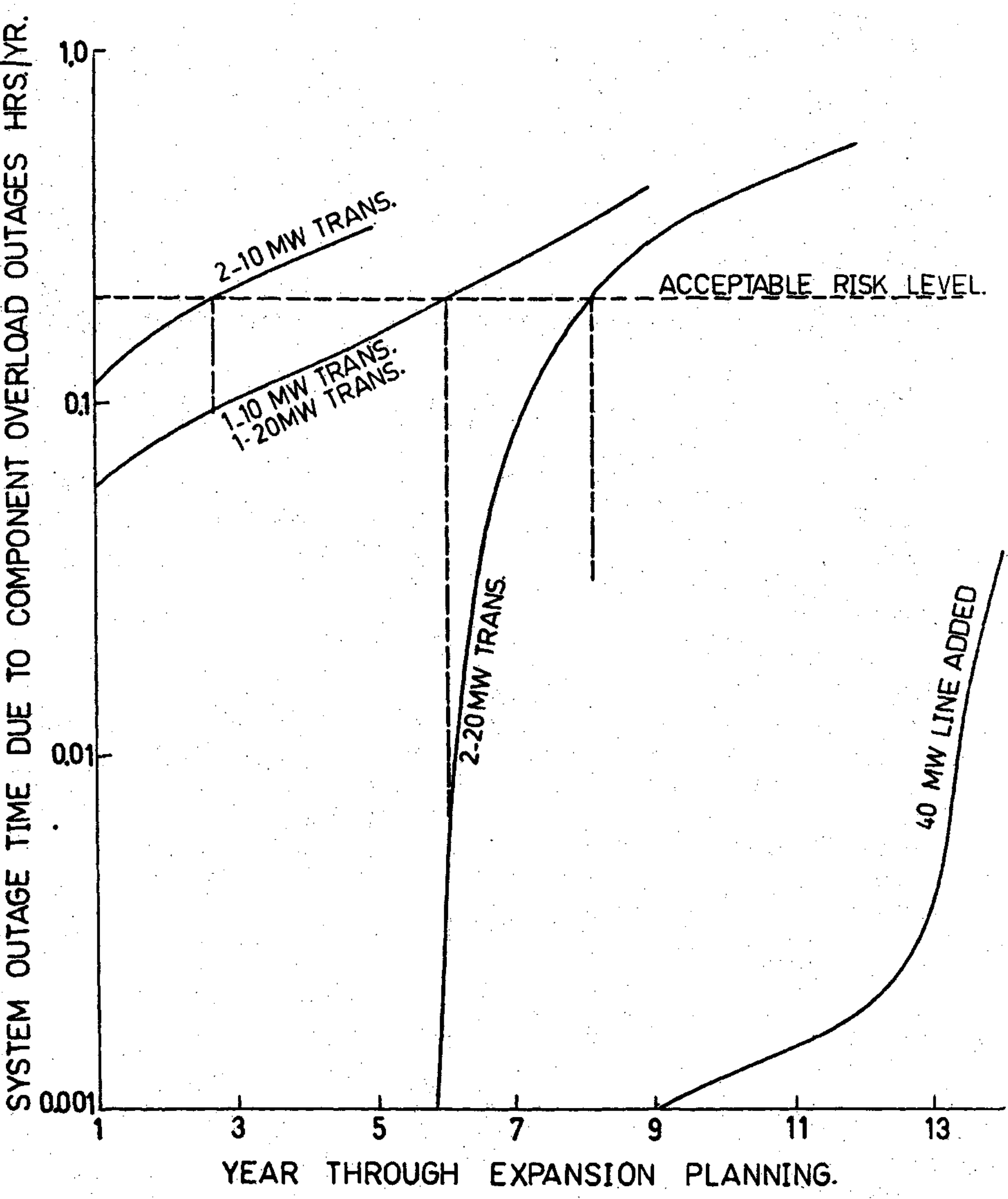


Figure 5.2 System Total Outage Time Due to Component Overload Outages as a Criterion of Substation Expansion Planning.

(iii) directly. The acceptable level of interruption time requires that step (i) of the expansion be carried out in between years 2 and 3, step (ii) in year 6 and step (iii) in year 8. This analysis when performed in conjunction with present worth studies, can result in the selection of a reliable and economic expansion plan.

It should be noted that the acceptable levels of rate and duration indices affect the expansion pattern significantly and when considered together can give preference to different plans. In such cases, the expected loss of component life, determined using the expected overload values (as described in the previous section) and their frequency and duration of occurrence, can provide a unified index for planning purposes. This will require determination of acceptable levels of loss of life for different components in the system.

5.7 Evaluation of Overload Outage Indices in Subtransmission Systems

In all the previous examples, the systems considered have contained only a single load point. In system configurations involving many load points, the evaluation of interruptions due to component overload outages becomes quite involved. A prohibitive amount of effort and computation is required to perform load flow studies to determine the load values at which overload outages commence. This is evident from the computations illustrated in reference 36. The amount of computation can be considerably decreased and load flow studies avoided by using a cut set approach[21]. The following assumptions are made in the application of this method.

(i) Loadings on the components are proportional to the bus loads they supply.

(ii) Component capabilities provide adequate voltage levels at the different buses.

The computer program described in Chapter 3 is used to determine the cut sets for various load points in the system. The cut sets which are common to certain load points carry the total load at those points. The outage indices which result from these cut sets are determined using equations 5.7 and 5.8. The load parameters λ_L and r_L used in these equations are evaluated by considering the total chronological load curve for the load points having the cut set under consideration. The contribution to the outage indices due to cut sets which are associated with only one load point is also calculated using equations 5.7 and 5.8. The load parameters, λ_L and r_L, for this case are evaluated by considering the chronological load curve at the load point for which the cut set under consideration is appropriate. The contributions of different cut sets for a load point are evaluated separately and the results are combined to obtain the frequency and duration indices due to component overload outages. A considerable reduction in computer time may be achieved in some systems by using load cycles which are representative of the different periods. A further reduction in computation time is achieved by discarding those cut sets which do not contain components liable to suffer overloads.

The subtransmission system shown in Figure 5.3 was considered in reference 36 to illustrate the evaluation

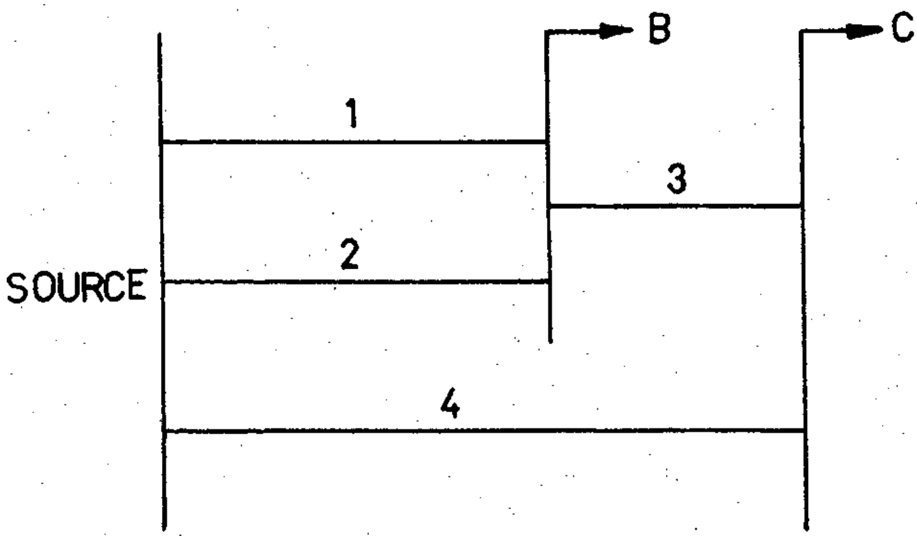


Figure 5.3 A Simple Subtransmission System

of interruption indices due to component overload outages by using some of the techniques reviewed in section 5.2. The same system is utilized to illustrate the application of the cut set approach outlined above. The component parameters used in this study are given in Table 5.6. The load model, also given in Table 5.6, and the line capabilities of 100 Mw and 80 Mw as used in reference 36 were considered to compare the results evaluated from several other techniques[36] with those obtained by the cut set approach.

The various cut sets for load points B and C are

TABLE 5.6

COMPONENT PARAMETERS AND THE LOAD MODEL FOR THE SYSTEM IN FIGURE 5.3 [36]

Line	Component Parameters: Failure Rate f/yr.	Component Parameters: Expected Repair Time Hrs.	Load Model: Peak Load Mw	Load Model: No. of Occurrences Per Period
1 or 2	0.5	7.5	100	4
3	0.1	7.5	90	4
4	0.6	7.5	80	4
			70	4
			60	4
			50	20

Average duration of a normal weather period=200 hrs.

Average duration of an adverse weather period = 1.5 hrs.

Line capabilities of 100 and 80 Mw are assumed for the two cases studied.

Number of days in the period=20.

Expected duration of peak load = 0.5 day.

shown in Figure 5.4. It is clear from this figure that the cut set with components 1, 2 and 4 is common to both the load points B and C. The contribution of this cut set to

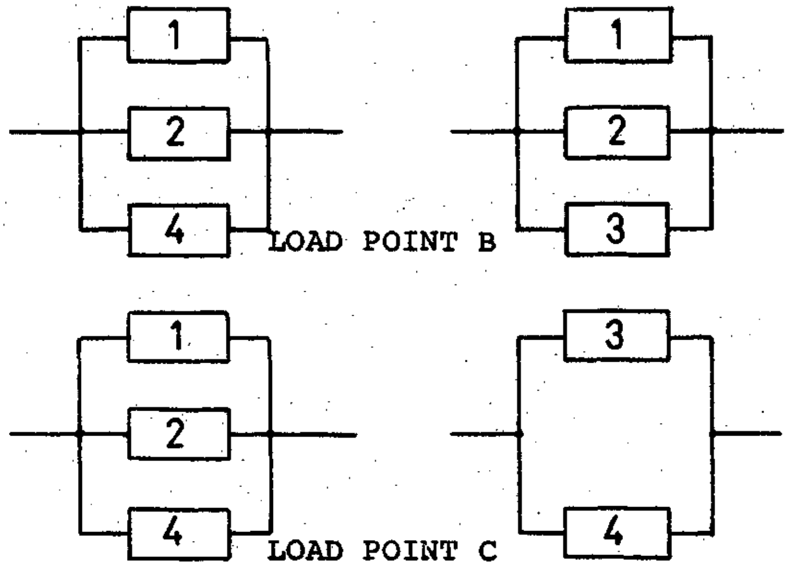


Figure 5.4 Cut Sets for the System in Figure 5.3

the overload outage indices is evaluated using the combined chronological load curve for load points B and C. The respective chronological load curves at points B and C are used to evaluate the overload outage indices for the cut sets involving components 1, 2 and 3 for load point B and 3 and 4 for load point C. The results obtained by the simple cut set approach are compared in Table 5.7 with those given by the techniques reviewed in section 5.2. It is evident from the table that the cut set approach gives results which compare reasonably well with the more accurate approaches presented in the literature[36].

It should be noted that the methods illustrated in reference 36 for the computation of overload outage indices require load flow studies and Markov analysis. The computations

TABLE 5.7

INTERRUPTION RATE AND DURATION DUE TO COMPONENT OVERLOAD OUTAGES

Method	Index	Line Capability = 100 Mw		Line Capability = 80 Mw	
		Load Pt. B	Load Pt. C	Load Pt. B	Load Pt. C
Extended conditional Probability method [36]	Frequency, f/yr	0.00095	0.00095	0.520	0.552
	Duration, hrs.	2.9	2.9	4.6	4.6
Extended contingency curve method [33]	Frequency, f/yr	0.00095	0.00095	0.520	0.553
	Duration, hrs.	2.9	2.9	4.6	4.6
Conditional probability method [34]	Frequency, f/yr	0.000728	0.000831	0.320	0.341
	Duration, hrs.	3.75	3.92	7.50	7.45
Cut Set Approach	Frequency, f/yr	0.00093	0.00093	0.520	0.551
	Duration, hrs.	2.9	2.9	4.61	4.61

were considerably eased by assuming the load to stay at some high value for half a day and a low value for the remaining half of the day. The loads at points B and C were considered to be completely correlated.

In many cases, however, the load model in which a constant exposure to high and low load periods is assumed may not be valid. The loads at different points may not be completely correlated. The cut set approach considers the chronological loads at different points and therefore allows for the inclusion of diversity in loads and varying exposure to high load periods. The overload outages caused due to bunching of component failures in adverse weather can also be considered by a cut set approach. These considerations are illustrated in Figures 5.5, 5.6, 5.7 and 5.8 for the subtransmission system shown in Figure 5.3. Figures 5.5 and 5.6 show the effect on the outage rate and total outage time indices respectively (due to component overload outages) of varying the high load period durations. The effect of varying component capabilities and adverse weather associated failures is also illustrated. It is assumed that adverse weather periods occur at random throughout the year. The figures clearly show that exposure to high load periods, component capabilities, component adverse weather associated failures have a significant effect on the overload outage indices. Figures 5.7 and 5.8 respectively show the effect on the outage rate and total outage time indices of diversity in loads at load points B and C. It is clear from these

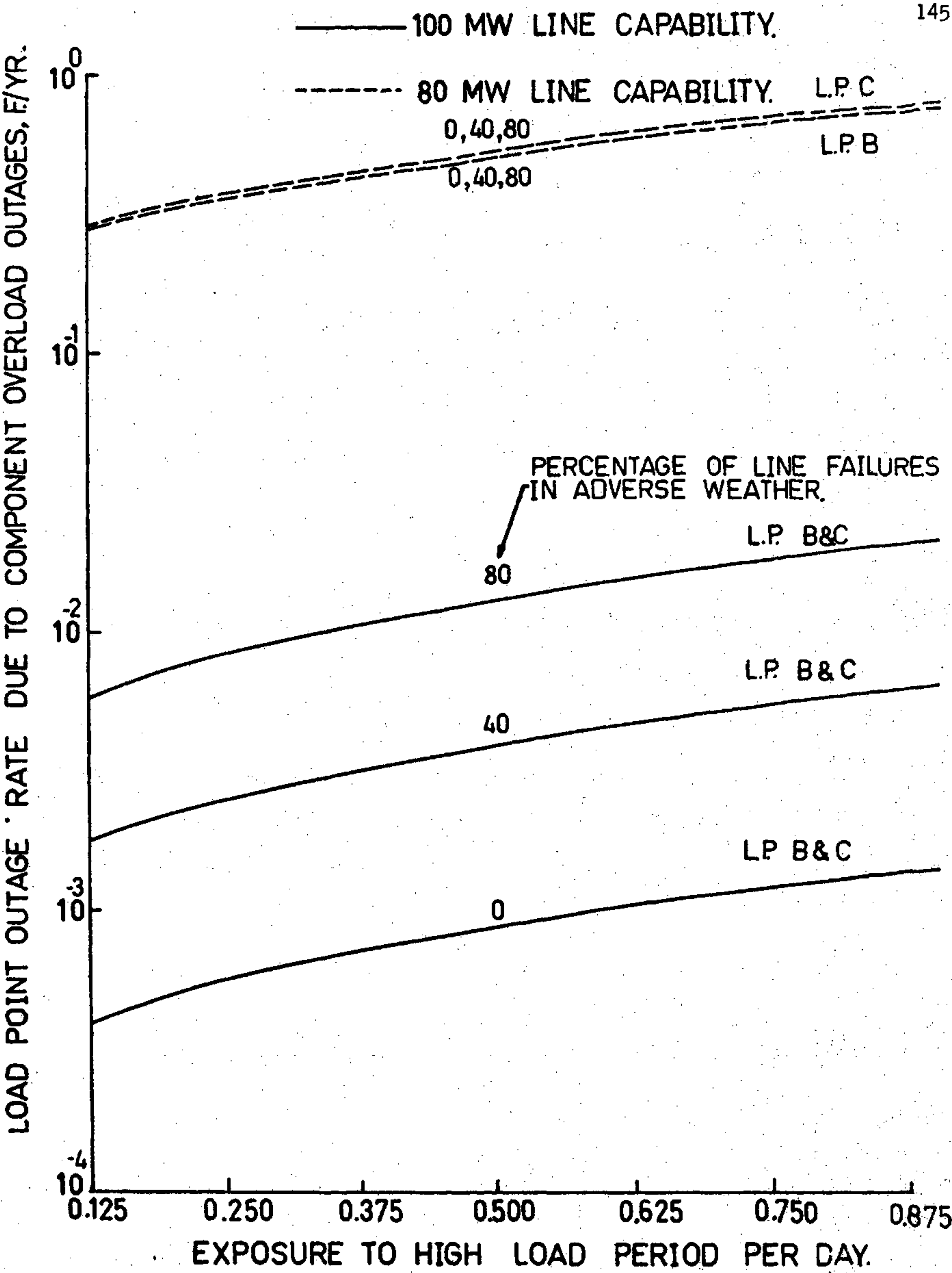


Figure 5.5 Effect on Outage Rate Due to Component Overload Outages of Varying High Load Period Durations.

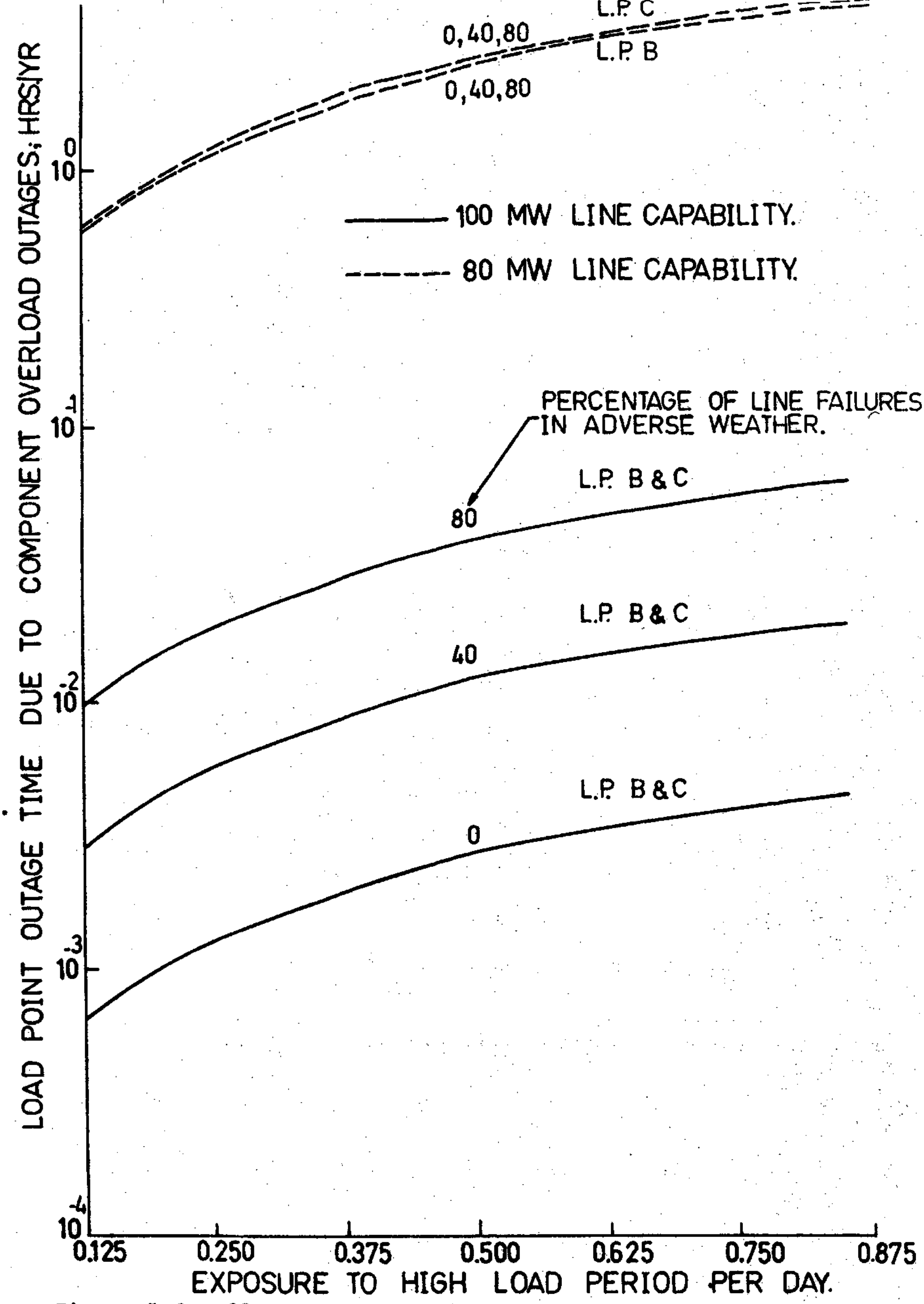


Figure 5.6 Effect on Outage Time Due To Component Overload Outages of Varying High Load Period Durations.

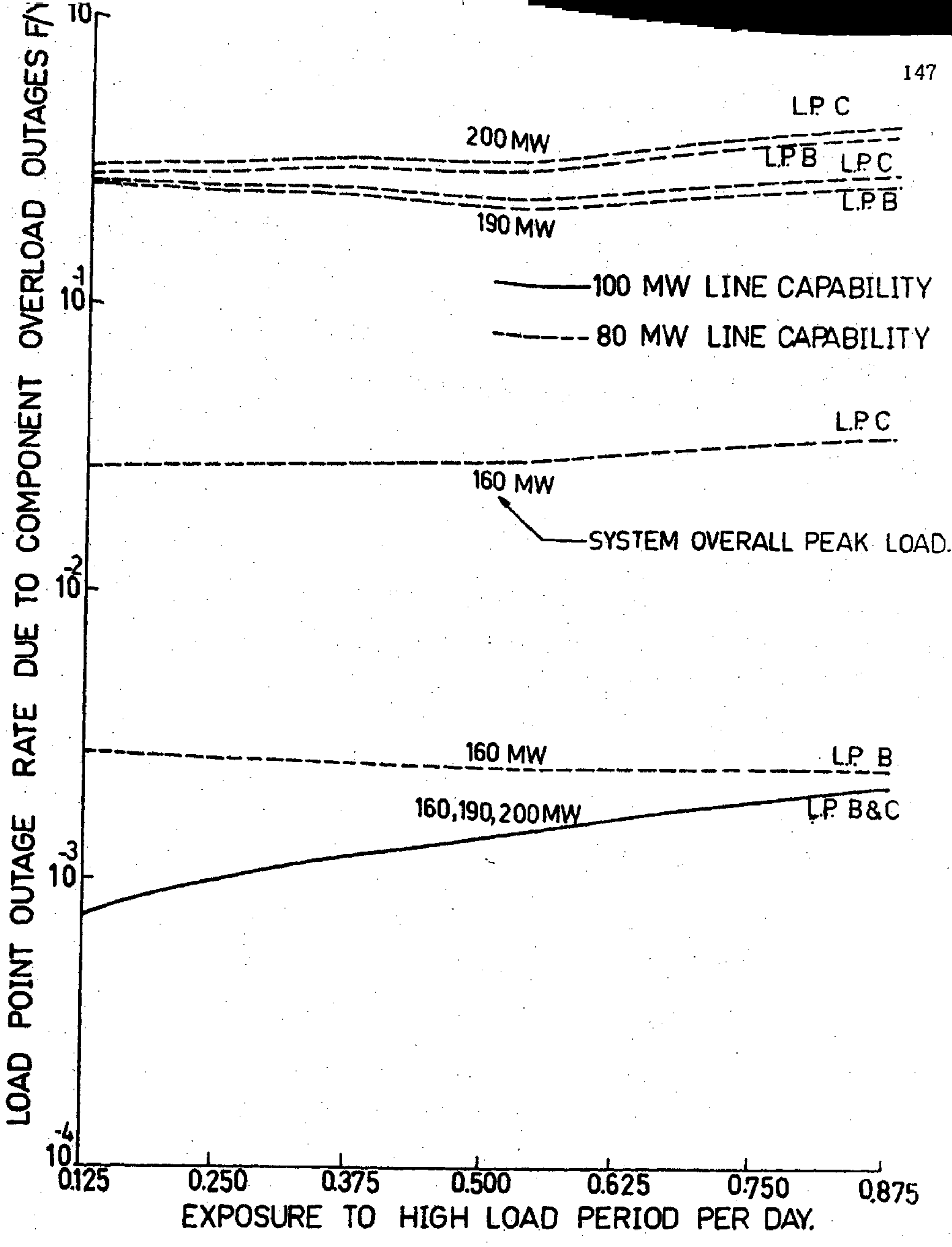


Figure 5.7 Effect on Outage Rate Due to Component Overload Outages of the Diversity in Bus Loads.

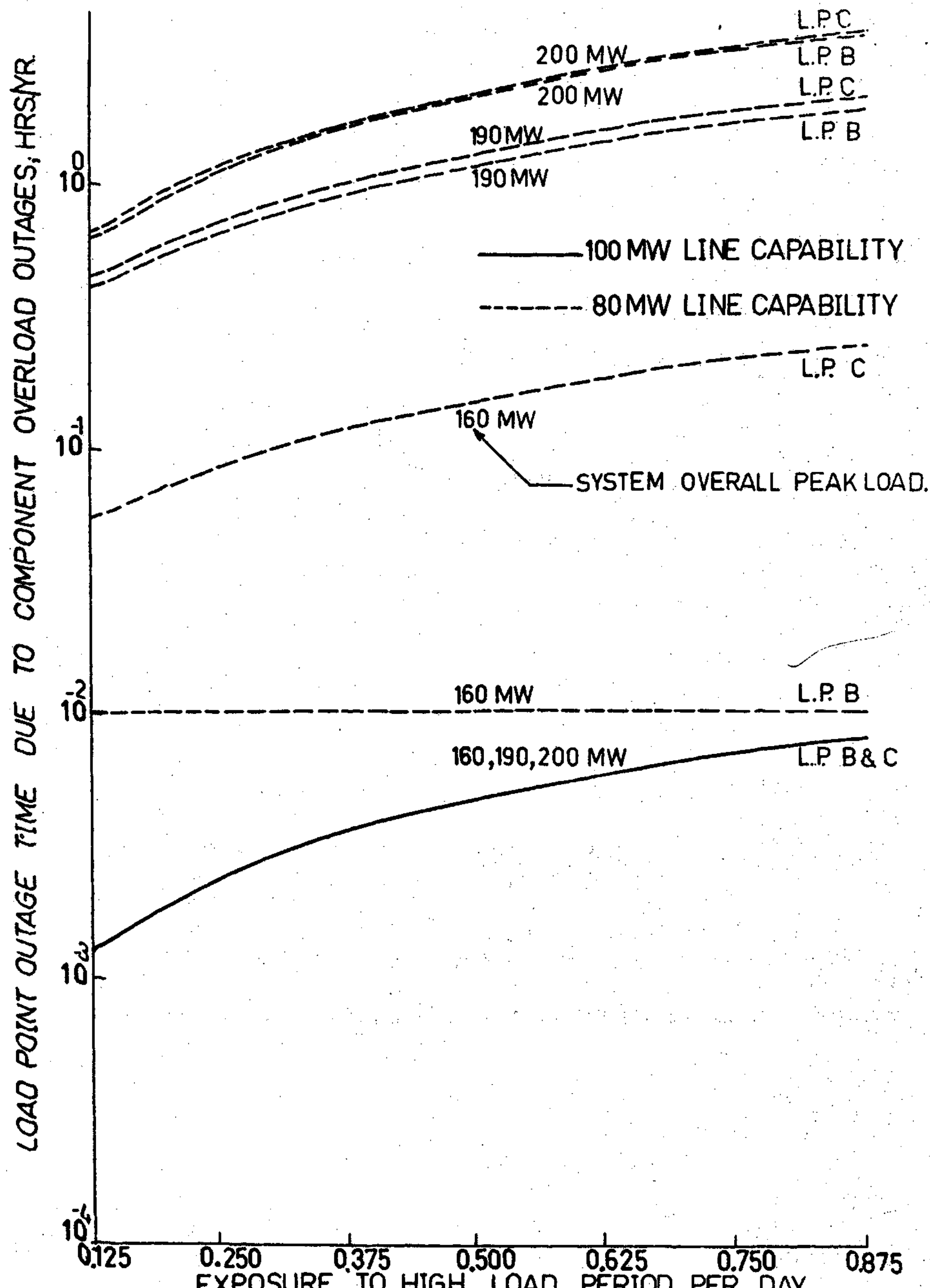


Figure 5.8 Effect on Outage Time Due to Component Overload Outages of the Diversity in Bus Loads.

figures that overload outage indices are significantly affected by diversity in the loads at the various points. The greater the load diversity, the lower is the probability of encountering component overloads.

5.8 Summary

Power system networks due to economic considerations often involve components with carrying capabilities which are lower then the loads they may be called upon to carry in different contingency states. This practice admits an associated loss in reliability due to component overload outages. In this chapter, some of the available techniques for the evaluation of interruptions due to component overload outages are reviewed. The effects on outage indices of two different modes of service restoration after the overload outages have occurred are examined. The additional indices of expected component overload, expected load and energy loss indices are introduced to estimate the severity of overloads. The application of the overload outage indices in expansion planning studies of substations is also illustrated. Such studies when performed in conjunction with present worth analysis can provide a useful input to the selection of a reliable and economic expansion plan.

It has been illustrated in the published literature that the evaluation of overload outage indices in systems involving many load points requires a prohibitive amount of computer time due to the associated Markov analysis and load flow studies. This chapter has illustrated the application of a cut set approach to minimize the computation time and effort. The results obtained by this approach are compared with those obtained from more accurate techniques. A close proximity in the results in the cases considered has been observed. The effects on overload outage indices of component capabilities, high load durations, weather associated failures, maintenance considerations, diversity in loads etc. are illustrated.

6. QUANTITATIVE EVALUATION OF COSTS OF SUPPLY INTERRUPTIONS

6.1 Introduction

The basic objective of electric power utilities is to satisfy the customer requirements as economically as possible and with a reasonable level of continuity and quality. The customer reaction to the continuity and quality of service being provided is therefore of prime significance in determining an acceptable level of system performance. As noted in Chapter 2, the average customer judges the quality of his service on the basis of a composite reaction to any interruption he may experience. Assuming satisfactory voltage levels, the customer reaction is dependent upon the following factors:

(a) Frequency of interruptions.

(b) Duration of an interruption.

(c) Number of customers or the amount of load interrupted.

(d) Time of the day at which the interruption occurs.

(e) Season of the year in which the interruption occurs.

(f) Apparent reason for an interruption.

A survey was conducted in 1959 by Public Service Electric and Gas Company, Newark, to measure customer dissatisfaction with service in terms of "resentment" relative to the above factors[37]. Assuming an average mix of industrial, commercial and residential customers, the following conclusions were drawn.

(i) Resentment is roughly proportional to the frequency of outage and increases rapidly for frequencies greater than one per year.

(ii) Resentment is roughly proportional to duration. It begins to rise rapidly after 6 hours and multiplies very rapidly after 24 hours.

(iii) Resentment is relatively independent of magnitude of load interrupted up to 10 Mw.

(iv) Outages during the evening period cause about 2.5 times the resentment produced by day time outages. Outages during the night period cause only about one third the resentment of a day time outage.

(v) In comparison with outages during the mild weather periods in spring and fall, outages during the summer air conditioning season cause twice the resentment and those occurring during the winter heating season 5 times the resentment.

(vi) Resentment caused by an unexplained outage is nearly 3 times that resulting from a natural catastrophe.

The above conclusions are derived considering the system as a whole and may not be applicable to any particular customer. It should, however, be noted that the customer resentment index is quite difficult to quantify and a physical appreciation and interpretation may not be possible. In addition, this index does not provide any indication of the monetary benefits obtained by alternative system improvements and operating procedures. This chapter considers the costs of supply interruptions as a measure of customer satisfaction. This provides a basis for the comparison of systems in which there is no consistent difference between the outage rate, duration and total outage time indices of system reliability. The application of interruption costs in the evaluation of effectiveness of various improvement plans is also presented in this chapter.

6.2 The Costs of Supply Interruptions

The techniques offered in the previous chapters can be efficiently used for cost effectiveness studies. The costs and the reliability benefits associated with a particular improvement plan can be calculated. The costs and the effectiveness, however, are not in commonsurate units. This analysis permits the selection of a most cost effective choice but does not give any indication of whether the decisions are worth implementing. This objective can be achieved by performing cost-benefit studies. The costs and the benefits must be in the same units. It is evident, however, that cost-benefit analysis is more difficult to perform as it requires more data than a cost-effectiveness analysis.

The assessment of costs of supply interruptions provides a basis for cost-benefit studies in power systems. Two basic approaches are possible. The first approach considers the viewpoint of the power utility. Interruptions to customers may result in the following costs to the utility.

(i) Loss of revenue from customers not served.

(ii) Loss of customer goodwill.

(iii) Loss of future potential sales due to adverse customer reaction.

It should be noted that if these costs were the only factors employed in cost-benefit studies, a very poor quality of customer supply could be justified. Since the primary utility objective is to satisfy the customer needs, an alternative approach is therefore to consider the viewpoint of the customer. The interruption frequency and duration, the amount of load interrupted and the time at which the interruptions occur are some of the factors which influence the supply interruption costs. These costs are also likely to vary widely depending upon the type of consumer. An industrial consumer may suffer losses due to lost production, spoiled product, equipment damage, idle production facilities and labour etc. An agricultural consumer can incur following costs due to supply interruptions:

(i) Labour cost for hand milking of the dairy herd.

(ii) Loss of some of the milk production.

(iii) Cost of grain destroyed during the drying season.

(iv) Loss of some of the livestock, egg and poultry production etc.

A domestic consumer may suffer actual out-of-pocket economic loss only if the interruption is quite extended, but may also suffer other unquantifiable losses associated with his comfort and convenience.

A method involving a national viewpoint was suggested in reference 39 to determine the dollar value of a kwh curtailed. Using this approach, the cost of the interruption in dollars per kwh is obtained by dividing the GNP for a year by the kwh consumed during the year. This procedure gives a value of approximately $0.60 per kwh of interruption in the U.S.[39]. It should be noted that the application of the costs based on GNP and yearly kwh consumption is only valid for broad studies which are national in scope. In single systems, a better approach is to estimate the costs of interruptions as experienced by different types of customers. The principal method of estimating these costs is to directly question the consumers as to how they themselves value the availability of electricity at their premises. The expected values for costs of interruptions with different types of customers can, therefore, be obtained. This procedure has been used in Sweden to estimate the cost of supply interruptions to industrial, domestic, agricultural and commercial consumers[38]. A similar method was used by the Reliability Subcommittee of the Industrial and Commercial Power Systems Committee of the I.E.E.E. to estimate the costs of supply interruptions to industrial plants. A summary of the results obtained by questioning 30 companies covering 68 plants in 9 industries in the U.S.A. and Canada was made available in a recent paper[40].

It is recognized that the interruptions costs should be split into two components, i.e., dollars per kw interrupted and dollars per kwh of interruption. This is essential because some of the costs are proportional to the number and magnitudes of interruptions while other costs are proportional to the amount of energy interrupted. Thus each customer can be asked to provide estimates of the following two costs:

(i) Dollars per failure -

This includes extra expense incurred due to a failure only excluding the costs of downtime. For industrial consumers, this will involve costs of damaged equipment, spoiled product, extra maintenance and extra repair costs.

(ii) Dollars per hour of downtime -

This includes the expenses incurred due to the nonavailability of electrical energy during a certain period of time. For industrial customers, this includes the estimated revenues of product not made less expenses saved in labour, material, utilities etc.

These costs are likely to vary during different periods of the day and the seasons of the year. Considering that the interruptions are equally likely to occur at any time, the above costs represent only the expected values.

The estimates of the costs of interruptions for industrial plants, as reported by I.E.E.E. sponsored survey [40] are given in Table 6.1. It is clear from this table that plants with a maximum demand less than 1000 kw have much higher supply interruption costs than plants with a maximum demand of greater than 1000 kw. This indicates that small industrial plants have a higher cost of interruptions than large industrial plants. It should, however, be recognized that the per kw and per kwh cost estimates vary considerably between different consumers and within individual consumer groups.

TABLE 6.1

AVERAGE COST OF SUPPLY INTERRUPTIONS FOR INDUSTRIAL PLANTS IN U.S.A. AND CANADA[40]

Plants	\$/kw	\$/kwh
All Plants	1.89	2.68
Plants with Max. Demand > 1000 kw	1.05	0.94
Plants with Max. Demand < 1000 kw	4.59	8.11

If the per kw and per kwh cost estimates for different types of customers are available, the costs incurred due to service interruptions in a system can be easily calculated by using the following equation:

$$C_s = \Sigma_i \; (a_i \lambda_i + b_i \lambda_i r_i) \; P_{ei} \tag{6.1}$$

where

C_s = The total cost of supply interruptions.

a_i = The cost per kw of load interrupted for customer i.

b_i = The cost per kwh of interruption for customer i.

λ_i = The frequency of interruption for customer i.

r_i = The average interruption duration for customer i.

P_{ei} = The expected load interrupted per interruption for customer i.

6.3 System Applications

The costs of supply interruptions can be utilized in the evaluation of many different aspects of the reliability problem. These costs can be used to arrive at a unified index of reliability. It was noted in Chapter 3 that the outage rate and total outage time indices of reliability can give preference to different substation configurations. Using costs of service interruptions at a load point, the outage rate and the total outage time can be assigned economic penalties to obtain a composite index for the comparison of various alternative configurations. This is illustrated in Figure 6.1 for the simple substation configurations shown in Figure 3.5. The following data were assumed for the costs of supply interruptions.

Cost per kw interrupted = $1.0.

Cost per kwh interrupted = $1.3.

When the criterion of continuity of supply to any one of the two load points is considered, the expected value of load interrupted per interruption was assumed to be 2 Mw. In the case of a criterion involving continuity of supply to both the load points, the expected amount of load interrupted per interruption was assumed to be 1 Mw per load point. It is clear from Figure 6.1 that the first criterion of system successful operation gives preference to the system in Figure 3.5f, i.e., a ring bus configuration, whereas the second criterion gives preference to system in Figure 3.5g, i.e., a breaker and a half scheme.

The costs of supply interruptions can also be utilized for the evaluation of benefits associated with having spare transformer capacity, standby units etc. This

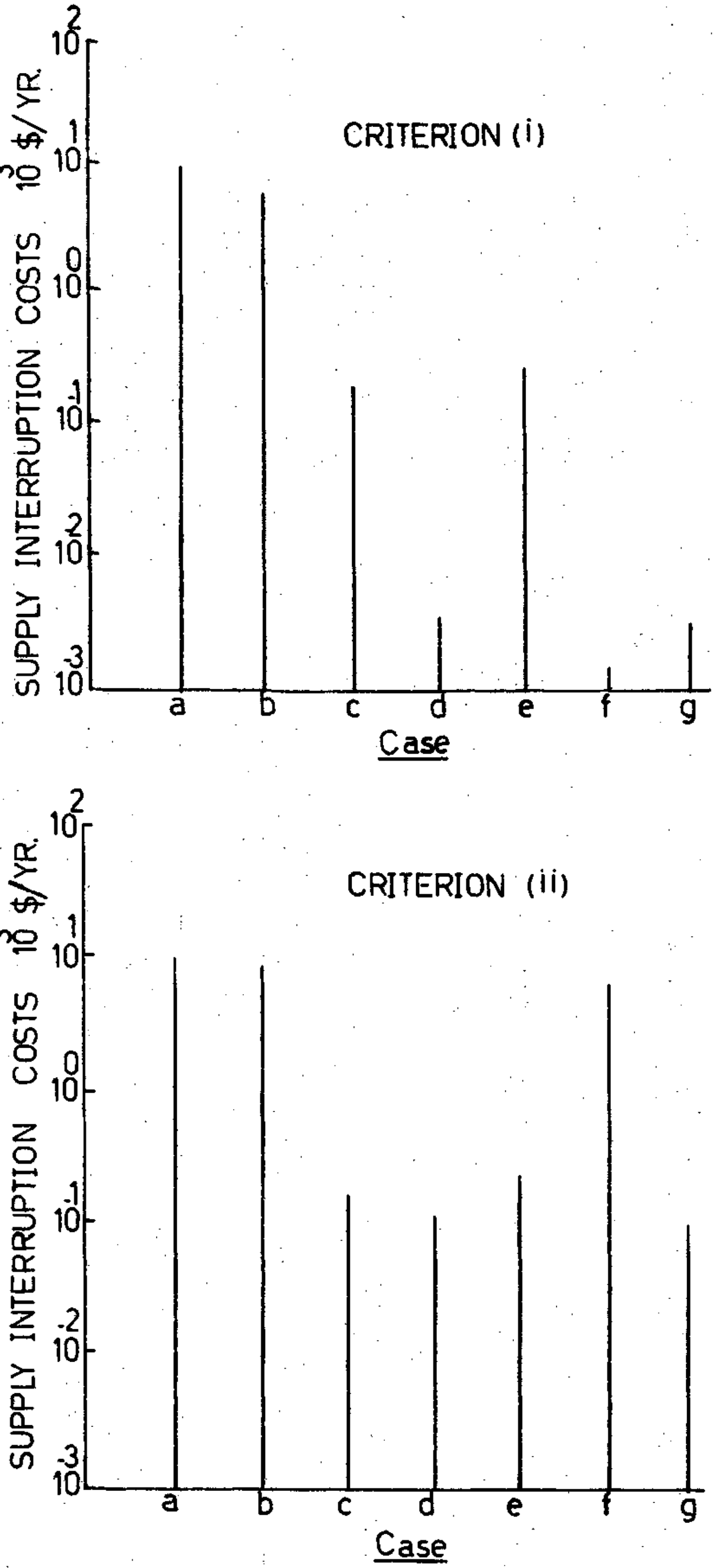


Figure 6.1 Costs of Supply Interruptions as a Basis for Comparison of Systems in Figure 3.5.

aspect is illustrated by considering the substation configuration shown in Figure 3.9. Following data for the costs of service interruptions were assumed for this study.

Cost per kw interrupted = \$2.00.

Cost per kwh interrupted = \$3.50.

Expected load interrupted per interruption = 10 Mw.

Using these costs and the component outage data given in Table 3.4, the cost of service interruptions at the substation bus as obtained from equation 6.1 is \$49,185.60 per year. If a spare transformer can be made available within 20 hours, the interruption cost is reduced to \$8,008.50 per year, a net decrease of \$41,177.10 per year. This can probably offset the cost of a spare transformer within three years. It is, therefore, advisable in such a case to have a spare transformer. This conclusion may not be valid if the repair time of the transformer (1000 hours in this case) is relatively small. This conclusion may also not be valid if the cost per kwh of interruption is very small. Another possible method to reduce the costs of interruptions is to provide a standby unit to pick up the load in the event of failure of the main supply. In the case of the substation example, if the time required to bring the standby unit on line is one hour, the cost of supply interruptions is \$7,949.10 per year. This cost decreases considerably if the time required to bring the standby unit on line is reduced. This is shown in Figure 6.2. The advantage in having a standby unit can only be justified if its annual capital and operational cost is less than the annual

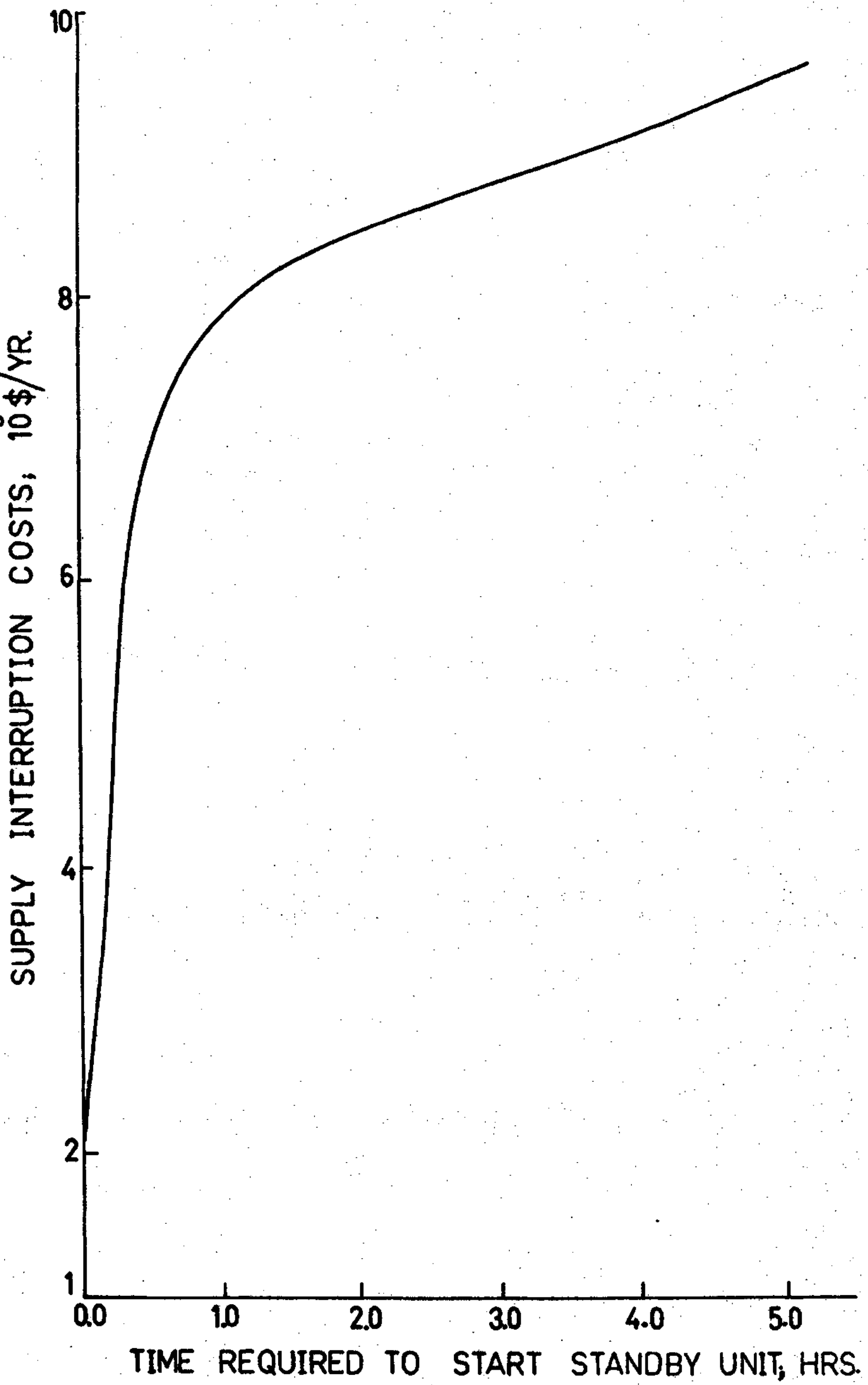


Figure 6.2 Costs of Supply Interruptions as a Function of the Time Required to Bring Standby Unit on Line.

cost of interruptions averted by the use of standby unit.

Another application of the costs of supply interruptions is illustrated by considering the distribution system shown in Figure 2.4. It is assumed that this distribution system serves industrial customers at different load points. The cost data used in this study are as follows:

Load points 2 and 5 -

$a = \$1.5/kw$, $b = \$5.0/kwh$, $C = 1$ minute,

$d = 0.0$ hrs., $P_e = 10$ Mw.

Load point 3 -

$a = \$3.5/kw$, $b = \$15.0/kwh$, $C = 5$ minutes,

$d = 0.0$ hrs., $P_e = 8.0$ Mw.

Load point 4 and 6 -

$aPe = \$3,000.00$, $bPe = 10,000.0$, $C = 0.5$ hours,

$d = 10$ minutes, $e = 0.70$

In the above,

a, b and P_e are the same symbols as used in equation 6.1.

C = The duration of time for which the interruption does not cause any economic loss.

d = The time required to restart the plant after the service is restored.

e = The fraction of time during which economic loss can occur.

The costs of supply interruptions calculated at different load points with and without line section 8 between buses 5 and 8 are given in Table 6.2. As expected, with the introduction of line section 8, the maximum benefit is ob-

TABLE 6.2

THE COSTS OF SUPPLY INTERRUPTIONS

Load Point	Cost of Interruptions, $/Year Without Line Section 8	With Line Section 8
2	3,819.15	2,534.52
3	8,293.25	5,526.68
4	1,276.98	480.73
5	5,476.91	33.27
6	727.64	98.77
Total Costs	19,593.93	8,673.97

tained by the customer at load point 5. This change in configuration also results in an overall decrease of $10,719.96 per year in the cost of supply interruptions for the entire system. Thus the worth of line section 8 for the year under study from the viewpoint of system customers is approximately $10,720.00. This value can be used in cost-benefit analysis to justify the proposed investment in line section 8. It should be noted that if instead of connecting buses 5 and 8 by line section 8, an additional line is provided between buses 1 and 2, the profile of cost of interruptions changes considerably. This is evident from Table 6.3.

In this case, the maximum benefit is obtained by the customer at load point 3. The overall decrease in cost of supply interruptions is $12,262.84 per year. This value is greater than the one obtained with a line section between

TABLE 6.3

COSTS OF SUPPLY INTERRUPTIONS FOR THE MODIFIED SYSTEM

Load Point	Cost of Supply Interruptions, $/Year
2	28.08
3	1,648.23
4	885.15
5	4,192.30
6	577.33
Total Costs	7,331.09

buses 5 and 8. This form of analysis, therefore, indicates the benefits obtained by different customers and the effectiveness of alternative improvement plans considering the economy of the service area as a whole.

It should be noted that if the system shown in Figure 2.4 (without line section 8) were underground with component temporary and maintenance outage parameters equal to zero, the addition of line section 8 cannot be justified. The overall annual cost of service interruptions with and without line section 8 in the system respectively are $1,567.0 and $780.0. A very insignificant decrease in the cost of supply interruptions is obtained with the addition of line section 8.

The cost of supply interruptions can also be used to determine how much it is worth to improve the reliability of components such as power transformers, circuit breakers, transmission lines etc. A reduction in the failure rate of

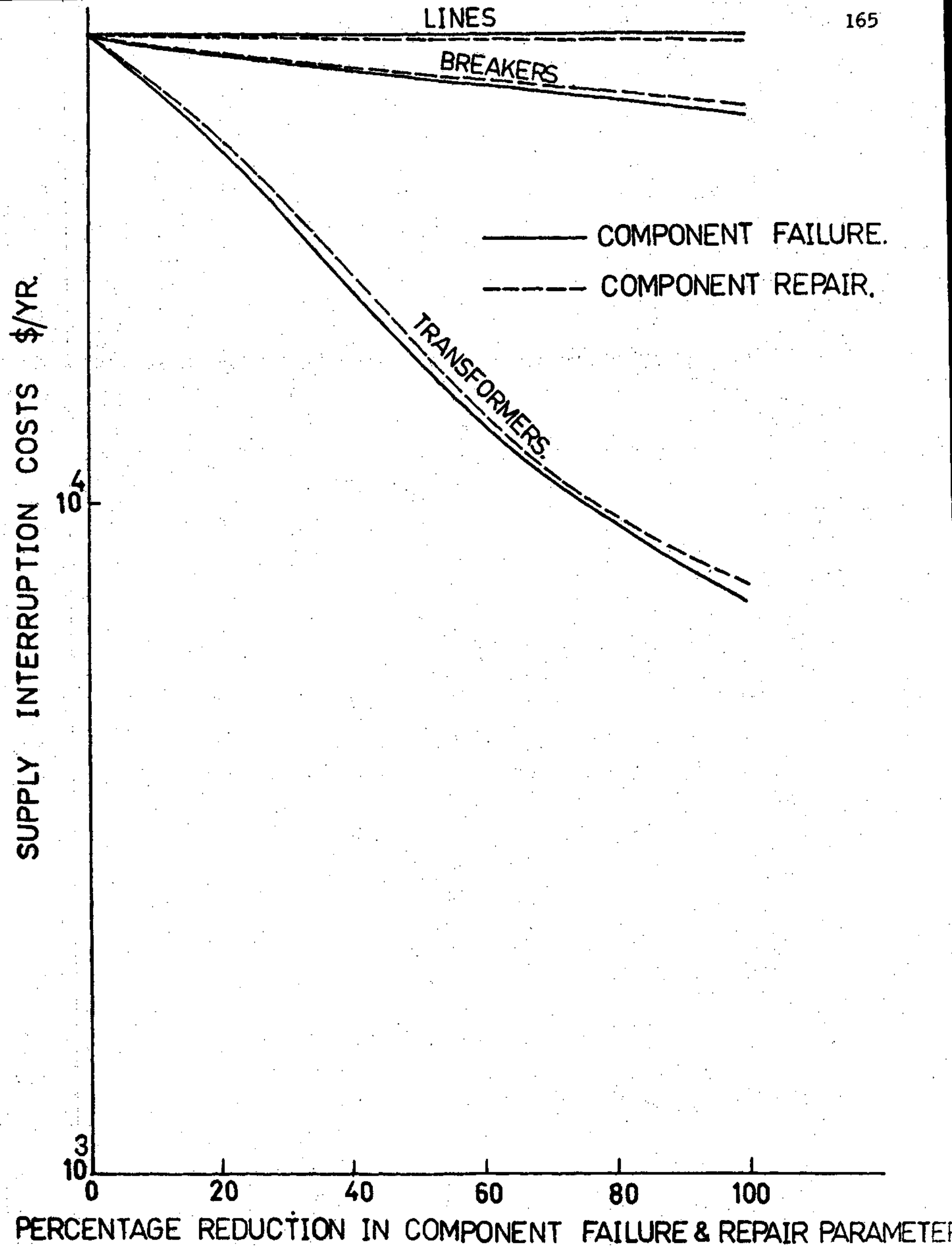


Figure 6.3 Effect on Supply Interruption Costs of Improvement in Component Reliability Performance.

a component may be worth the additional price paid on the purchase of the improved component. This is illustrated in Figure 6.3 by considering the substation example shown in Figure 3.9. It is clear from Figure 6.3 that the benefits associated with the improvement in reliability performance of circuit breakers and transmission lines are not very significant for the particular example under study. The cost of supply interruptions is decreased significantly by transformer reliability improvements. The decrease in interruption costs due to improved component performance should be compared with the costs required to achieve the improvements.

6.4 Summary

The prime objective of electric power utilities is to satisfy the consumer's demand for continuous supply as economically as possible. The utility should determine how much expenditure should be made to accomplish a given expected improvement in service. Since the consumer is not prepared to pay the price for extremely high operational reliability, the improvement expenditure should be based on the value of electric supply to the customer. The cost of supply interruptions as viewed from the customer's side of the meter is a valuable tool in estimating the dollar value of the availability of electric supply to the customer. This chapter presents a basis for the determination of supply interruption costs to different types of consumers. It is sometimes quite difficult to quantify some of the psychological factors as comfort, convenience, anger etc. in terms of dollars. The problem is not, however, insurmountable as what are really required are approximate and reasonable cost estimates.

This chapter has also illustrated the application of cost of supply interruptions in system studies. The cost of supply interruptions averted by the utilization of spare transformer capacity, standby units, additional facilities etc. can be calculated. These costs can then be taken as a basis for the assessment of economically justified investment in the system. The estimates of costs of supply interruptions also provide a basis for the comparison of systems in which there is not a consistent difference between the outage rate and duration indices of reliability.

7. CONCLUSIONS

This thesis has illustrated many different aspects of the transmission and distribution system reliability problem. Special emphasis has been placed on the evaluation of substation and switching station reliability performance. One of the main concerns has been the development of accurate and consistent models to represent the true component and system behaviour. Some aspects of the problem are so complex that an accurate model may sometimes become computationally unmanageable. Realistic models should therefore adequately represent the true performance and at the same time be mathematically tractable. This may require making some simplifying but reasonable assumptions.

System reliability performance in the thesis has been measured in terms of outage rate, average outage duration and total outage time per year. All three indices are important in order to make a meaningful comparison of various system configurations. The average outage duration is a relatively weaker index of reliability. A design may have the same number of long interruptions as another design, but the average duration may be diluted by other sustained interruptions whose duration is limited by short switching times. The reliability indices have been obtained at different load points of the system. This approach is very useful because a general level of system reliability does not indicate how the different continuity requirements of the customers are being satisfied.

The author's M.Sc. thesis[8] developed a set of equations for the evaluation of interruptions due to component permanent, temporary, maintenance and overload outage categories. The failure characteristics of components exposed to a changing environment were considered by using a two state weather model. The results given by the equations were shown to be quite close to those obtained by a theoretically accurate Markov approach[9,10]. This thesis has illustrated the application of the equations by a sequential and straightforward technique utilizing a simplifying cut set approach. A basic requirement of the analysis is the determination of equipment failure combinations which will cause interruption at the designated load point. The equations which are permanently stored in the computer memory are then called in according to the conditions of weather, repair, maintenance etc. for the evaluation of reliability indices. The resulting analysis indicates the relative severity of different failure categories and delineates efficient and effective means of improving system reliability.

Component failure models considering only one system effect can provide quite optimistic estimates of reliability indices. It is important to note that a line outage due to a phase to ground fault causes an entirely different response of the protective system than that caused by a conductor open type failure. The classification of component failure categories according to their system effects is therefore essential for accurate reliability predictions. This thesis has considered two modes of component failure designated as active and passive. The system effect of active failures is the outage of many other healthy components together with the failed component, whereas the passive failures involve the outage of the failed component only. Utilizing these concepts, a computer program has been developed to perform system reliability studies efficiently. The basic steps in the program involve:

(i) the determination of events and their possible combinations that can cause outage to the designated load point. The mode of service restoration corresponding to each failure event is also determined.

(ii) the calculation of outage frequency and duration indices using appropriate equations.

The performance of the failure modes and effects analysis (FMEA) in step (i) does not require any component outage data, and frequently the FMEA results are valuable indicators of system reliability. The program is capable of handling normally open or closed switches or breakers present in the system. The output of the program provides a detailed perspective of the system reliability performance.

Preventive maintenance policies can have a significant effect on the system reliability indices. The various considerations involved in the selection of a preventive maintenance program from a reliability viewpoint have been discussed in this thesis. The optimization of component reliability performance requires the establishment of functional relations between the failure and maintenance parameters. It has been illustrated that by properly co-ordinating the component maintenance, the contribution of the maintenance associated failure events to the system outage indices can be considerably reduced. It is recommended that co-ordinated maintenance be performed on those components which together are not present in any system cut set. The justifiable increase in component average maintenance time, to retain the benefits of co-ordinated maintenance, have also been analyzed in this thesis.

The evaluation of interruptions due to component overload outages, in systems with many load points is quite difficult. The reliability indices depend upon the mode of service restoration after the overload outages have occurred. Some of the available techniques for the evaluation of overload outage indices have been reviewed in this thesis. The effects on the reliability indices of two methods of service restoration, after the overload outages have occurred, have been illustrated. It has been shown that the cut set approach can be extended for the evaluation of overload indices in systems with many load points. The assumption is made that components have fixed carrying capabilities. This thesis has also illustrated the application of overload outage indices in the expansion planning of substations. This study when performed in conjunction with a present worth analysis can aid in the selection of a reliable and economic expansion plan.

Customer satisfaction expressed in dollars and cents is the ultimate measure of system reliability. There is no justification for increased reliability, especially if the customer has to be called upon to pay for it unless the increased reliability is worth as much or more to him. The costs of supply interruptions assessed by the customers themselves provide a basis for estimating the dollar value of the availability of electric supply at their premises. The application of interruption cost estimates in the evaluation of economically justified investments in the system has been illustrated. The economic benefits obtained by the utilization of spare transformer capacity, standby units, additional facilities etc. have been evaluated. These estimates can be used in cost-benefit studies for evaluating the incremental benefits associated with different improvement plans. Interruption cost estimates have been used for the comparison of systems in which there is not a consistent difference between outage rate and duration indices.

The methods of reliability assessment presented in this thesis supply quantitatively the probability ingredient missing from the contingency rule approach. The sensitivity studies on component and system parameters illustrated in various chapters are valuable in indicating overall system performance and in pinpointing system weaknesses. In contrast with many other possibly more sophisticated techniques, it is believed that the simple and sequential analysis presented will readily be accepted by system analysts and planners.

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9. APPENDICES

APPENDIX A

DEFINITIONS OF OUTAGE TERMS

A.1 Outage Definitions[13]

Outage

An outage describes the state of a component when it is not available to perform its intended function due to some event directly associated with that component.

Outage Categories

1. Forced Outage

A forced outage is an outage that results from emergency conditions directly associated with a component requiring that it be taken out of service immediately, either automatically or as soon as switching operations can be performed, or an outage caused by improper operation of equipment or human error.

2. Scheduled Outage

A scheduled outage is an outage that results when a component is deliberately taken out of service at a selected time, usually for the purpose of construction, preventive maintenance or repair.

Forced Outage Categories

1. Transient Forced Outage

A transient or temporary forced outage is an outage whose cause is self-clearing so that the affected component can be restored to service either automatically or as soon as a switch or circuit breaker can be reclosed or a fuse replaced. An example of a temporary forced outage is a lightning flashover which does not permanently disable the flashed component.

2. Permanent Forced Outage

A permanent or sustained forced outage is an outage whose cause is not self-clearing, but must be corrected by eliminating the hazard or by repairing or replacing the component before it can be returned to service. An example of a sustained forced outage is a wire burndown.

Weather Conditions

1. Normal Weather

Normal weather includes all weather not designated as adverse or major storm disaster.

2. Adverse Weather

Adverse weather designates weather conditions which cause an abnormally high rate of forced outages for exposed components during the periods such conditions persist, but do not qualify as major storm disaster.

3. Major Storm Disaster

Major storm disaster designates weather which exceeds design limits and which satisfies all of the following:

(a) Extensive mechanical damage,

(b) more than a specified percentage of customers out of service, and

(c) service restoration times longer than a specified time.

Examples of major storm disasters are hurricanes and major ice storms.

Exposure Time

Exposure time is the time during which a component is performing its intended function and is subject to outage.

Switching Time

Switching time is the period from the time a switching operation is required due to a forced outage until that switching operation is performed. For example, switching operations include reclosing a circuit breaker after a trip out, opening or closing a sectionalizing switch or circuit breaker, or replacing a fuse link.

A.2 Definitions of Customer and System Oriented Reliability Indices (14)

1. System Average Interruption Frequency Index

This index is defined as the average number of interruptions per customer served per time unit. It is determined by dividing the number of customer interruptions in a year by the number of customer served. This index may be applied to sustained and/or temporary interruptions, and this should be designated in the index.

2. System Average Interruption Duration Index

This index is defined as the average interruption duration for customers served during a specified time period. It is determined by dividing the sum of all customer interruption durations during the specified period by the number of customers served during that period.

3. Customer Average Interruption Frequency Index

This index is defined as the average number of interruptions per customer interrupted per time unit. It is determined by dividing the number of customer interruptions observed in a year by the number of customers affected. Count customers affected only once regardless of number of interruptions that may be experienced.

4. Customer Average Interruption Duration Index

This index is defined as the average interruption duration for customers interrupted during a specified time period. It is determined by dividing the sum of all customer interruption durations during the specified period by the number of sustained customer interruptions during that period.

APPENDIX B

CUT SET APPROXIMATIONS

Let C_i represent the ith minimal cut set for a particular load point. Let $\overline{C}_i$ denote the failure of this cut set. The probability of failure at the load point under consideration is given by:

$$P_F = P\left[\overline{C}_1 + \overline{C}_2 + \overline{C}_3 + \dots\dots\dots\right] \qquad \text{(B1)}$$

From the basic probability theory, the probability of occurrence of events A or B is given by:

$$P(A+B) = P(A) + P(B) - P(AB) \qquad \text{(B2)}$$

When probabilities P(A) and P(B) are very small, equation (B2) can be approximated as follows:

$$P(A+B) \simeq P(A) + P(B) \qquad \text{(B3)}$$

Equation (B3) provides an upper bound on the probability P(A+B). The failure probabilities of power system components are very small and therefore the probabilities $P(\overline{C}_1)$, $P(\overline{C}_2)$ .... are very much smaller. The expression (B1) can then be approximated by the following relation:

$$P_F \simeq P\left[\overline{C}_1\right] + P\left[\overline{C}_2\right] + P\left[\overline{C}_3\right] + \dots\dots$$

which provides a very close approximation of P_F. The system failure frequency can similarly be calculated by the following approximation:

$$f_F = \Sigma_i\ P(\overline{C}_i)\ \mu_{ii}$$

where μ_{ii} represents the sum of the repair rates of all the components contained in the cut set C_i.

APPENDIX C

OUTAGE RATE AND DURATION EQUATIONS COMBINING PASSIVE FAILURES AND MAINTENANCE OUTAGES

As noted in Chapter 3, component maintenance outages have the same system effect as do the component passive failures. These outage indices can be combined to obtain equivalent total outage rates and durations. This is shown below for a cut set of two components 1 and 2.

Equivalent total outage rate of component 1

$$= \lambda_1 + \lambda_1'' = \lambda_{e1}$$

Equivalent average outage duration of component 1

$$= \frac{\lambda_1 r_1 + \lambda_1'' r_1''}{\lambda_1 + \lambda_1''} = r_{e1}$$

Similar expressions can be written for component 2.

The contribution to the system failure rate due to this two component cut set is

$$\lambda_s = \lambda_{e1}\lambda_2 r_{e1} + \lambda_{e2}\lambda_1 r_{e2} \qquad \text{(C1)}$$

This equation takes into consideration that a maintenance outage cannot occur if there is some outage already existing in the system. The average duration associated with the failure rate λ_s is given by:

$$r_s = \lambda_{e1}\lambda_2 \frac{r_{e1}^2 r_2}{\lambda_s (r_{e1}+r_2)} + \lambda_{e2}\lambda_1 \frac{r_1 r_{e2}^2}{\lambda_s (r_{e2}+r_1)} \qquad \text{(C2)}$$

Equations (C1) and (C2) yield the following results:

$$\lambda_s = \lambda_1\lambda_2 r_1 + \lambda_1''\lambda_2 r_1'' + \lambda_2\lambda_1 r_2 + \lambda_2''\lambda_1 r_2'' \qquad \text{(C3)}$$

and

$$r_s = (\lambda_1 r_1 + \lambda_1'' r_1'')\ \frac{\lambda_2}{\lambda_s}\left[\frac{\lambda_1 r_1 r_2 + \lambda_1'' r_1'' r_2}{\lambda_1 r_1 + \lambda_1'' r_1'' + \lambda_1 r_2 + \lambda_1'' r_2}\right]$$

$$+ (\lambda_2 r_2 + \lambda_2'' r_2'')\ \frac{\lambda_1}{\lambda_s}\left[\frac{\lambda_2 r_2 r_1 + \lambda_2'' r_2'' r_1}{\lambda_2 r_1 + \lambda_2'' r_1 + \lambda_2 r_2 + \lambda_2'' r_2''}\right] \quad \text{(C4)}$$

Expressions (C3) and (C4) are similar to those obtained by using the combined equations of maintenance and passive failures given in Chapter 2. Similar considerations are applicable for cut sets involving larger number of components.

APPENDIX D

RELATION BETWEEN THE BREAKER MAINTENANCE OUTAGE RATE AND THE PROBABILITY OF STUCK BREAKER STATE

The state space diagram for a normally closed breaker protecting an equivalent component A is shown in Figure D.1. The equivalent component designated as A represents a set of system components the failures of which require the operation of the breaker under consideration. In Figure D.1,

λ_A = The failure rate of equivalent component A.

μ_A = The repair rate of equivalent component A.

λ_B = The failure rate of the breaker.

μ_B = The repair rate of the breaker.

λ''_B = The maintenance outage rate of the breaker.

μ''_B = The maintenance rate of the breaker.

λ''_A = The maintenance outage rate of equivalent component A.

μ''_A = The maintenance rate of equivalent component A.

λ_S = The rate of breaker stuck condition.

The λ_S value depends upon the breaker characteristics and is a function of the number of times the breaker is called upon to operate. In Figure D.1, the false trips of breaker have not been considered. It has been assumed that equivalent component A does not fail in the de-energized state (where breaker is in a failed state).

State 2 represents a condition where component A is working normally and the breaker is stuck. This state,

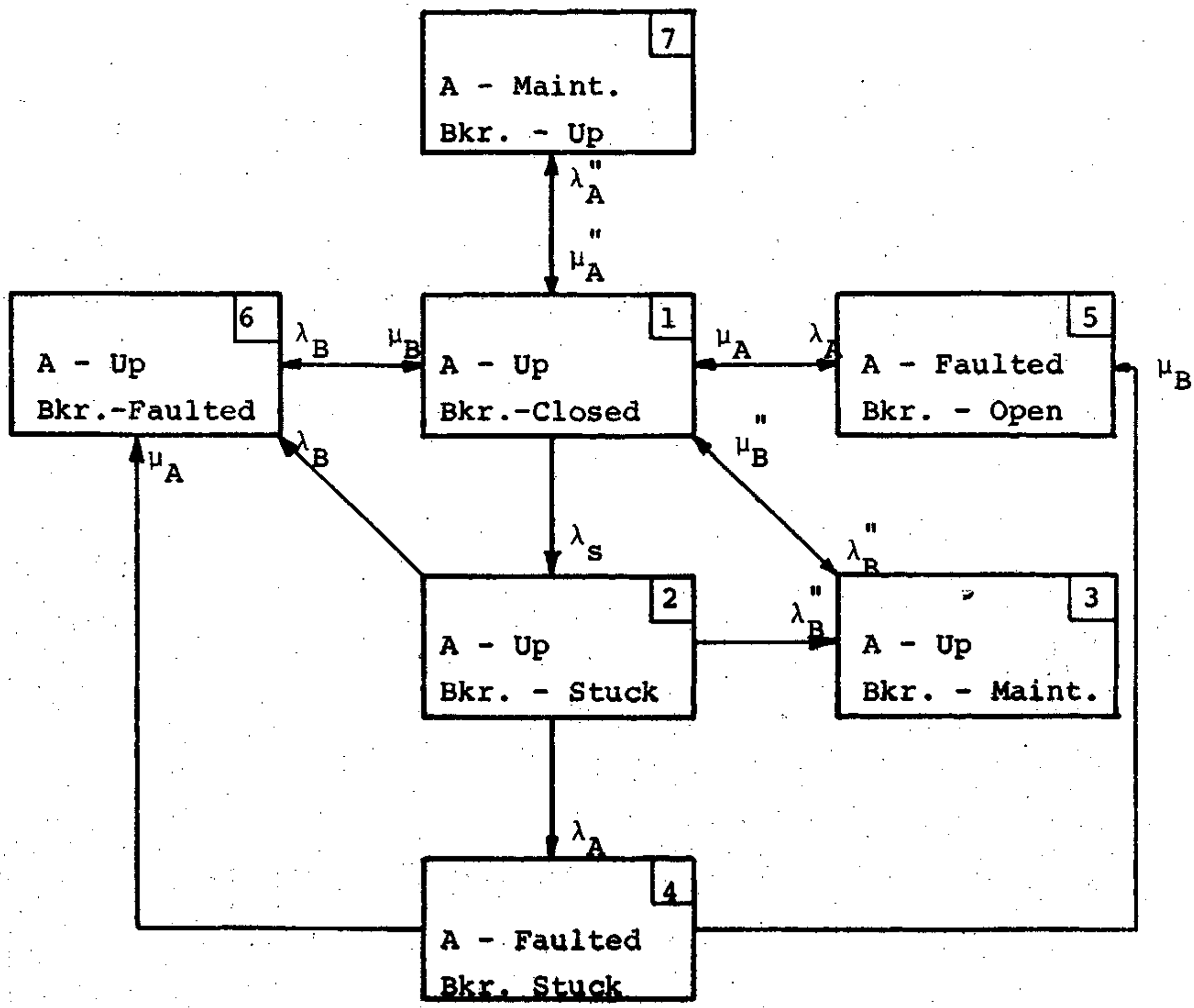


Figure D1 State Space Model For a Component Protected By A Breaker.

as shown in Figure D.1, is terminated by the following three events:

(i) The maintenance of the breaker is started.

(ii) The failures of equivalent component A.

(iii) The failures of the breaker.

Let P_i denote the probability of existence of the ith state. Under steady state conditions, the frequency of transitions into state 2 is equal to the frequency of transitions out of state 2. Therefore,

$$P_1 \lambda_s = P_2 \, (\lambda_B'' + \lambda_A + \lambda_B)$$

Or

$$P_2 = \frac{\lambda_s P_1}{\lambda_B'' + \lambda_A + \lambda_B}$$

Since $P_1 \approx 1$

$$P_2 = \frac{\lambda_s}{\lambda_B'' + \lambda_A + \lambda_B} \tag{D.1}$$

Equation D.1 clearly shows that if the maintenance rate of the breaker (λ_B'') is increased, the probability of a stuck breaker condition (P_2) can be significantly decreased.

APPENDIX E

SOME DATA COLLECTED FROM THE SASKATCHEWAN POWER CORPORATION SYSTEM

The author was with the Saskatchewan Power Corporation Regina for about a month collecting some component and system data. The following information was extracted from the SPC outage reports.

E.1 Outage Data

230 kv transmission lines

Number of circuit miles = 777.6, Number of lines = 7.

Years of experience = 3 (1970,71,72), Number of outages = 44.

Total outage time = 26042.5 minutes.

Permanent outage rate = 0.0189 f/yr/mile, Average outage duration = 9.84 hrs.

138 kv transmission lines

Number of circuit miles = 1403.5, Number of lines = 18.

Years of experience = 3 (1970,71,72), Number of permanent outages = 96.

Number of temporary outages = 21.0, Total outage time = 15556.5 minutes.

Permanent outage rate = 0.0228 f/yr/mile, Average outage duration = 2.71 hrs.

Temporary outage rate = 0.00499 f/yr./mile.

72 kv grid lines

Number of circuit miles = 194.2, Number of lines = 7.

Years of experience = 3 (1970,71,72), Number of permanent outages = 85.

Number of temporary outages = 15, Total outage time = 3291.5 minutes.

Permanent outage rate = 0.146 f/yr/mile, Average outage duration = 38.7 minutes.

Temporary outage rate = 0.0257 f/yr/mile.

138/72 kv transformers

Unit years of experience = 174. Number of permanent outages = 2.

Number of maintenance outages = 5.

Permanent outage rate = 0.0115 f/yr., Maintenance outage rate = 0.0287.

230 kv transformers

Unit years of experience = 63. Number of permanent outages = 0.

Permanent outage rate = 0.0 f/yr.

Other 138 kv transformers

Unit years of experience = 109. Number of permanent outages = 2.

Permanent outage rate = 0.019 f/yr.

72 kv transformers

Unit years of experience = 198. Number of permanent outages = 4.

Permanent outage rate = 0.02 f/yr.

E.2 Costs of Outages

Some estimates for the costs of service interruptions have been obtained by the Saskatchewan Power Corporation by directly questioning the customers. The estimates have not been separated into costs per kw and per kwh of interruption. Some of the interruption cost estimates obtained in year 1970 are given below:

Saskatchewan Minerals

One minute outage = \$50.00 to 150.00   Peak Load = 1 MVA

30 minutes outage = \$262.00 to 362.00

One hour outage = \$474.00 to 574.00

Outages longer than 3 hours in summer and one and one half hours in winter = \$4550 to 5282 + \$414 per additional hr. of outage.

Boh Beer

Cost per hour of interruption = Labour cost + Direct cost

= 175.00+1298.00=\$1473.00

Burns Food Limited

One minute outage = \$17.65   Peak Load = 1.5 MVA

30 minutes outage = \$529.50

One hour outage = \$1323.44

Pulp Mill

One minute outage = \$5000.00   Peak Load = 6 MVA

30 minutes outage = \$15000 to 25000

One hour outage = \$50000.00

Potash

One minute outage = \$600.00   Peak Load = 10-15 MVA

30 minutes outage = \$10000 to 20000

One hour outage = \$20000 to 40000

<u>Oil Refineries</u>

One minute outage = --- Peak Load = 6 MVA

30 minutes outage = $1000

One hour outage = $20000

<u>Hudson Bay, Regina</u>

One minute outage = $200.00 Peak Load = 1 MVA

30 minutes outage = $4500.00

One hour outage = $9000.00

<u>Canada Cement</u>

One minute outage = --- Peak Load = 2 MVA

30 minutes outage = $25.00

One hour outage = $50.00

E.3 The Substation Chronological Load Curve

The substation chronological load curve used in studies given in Chapters 3 and 5 is shown in Figure E.1.

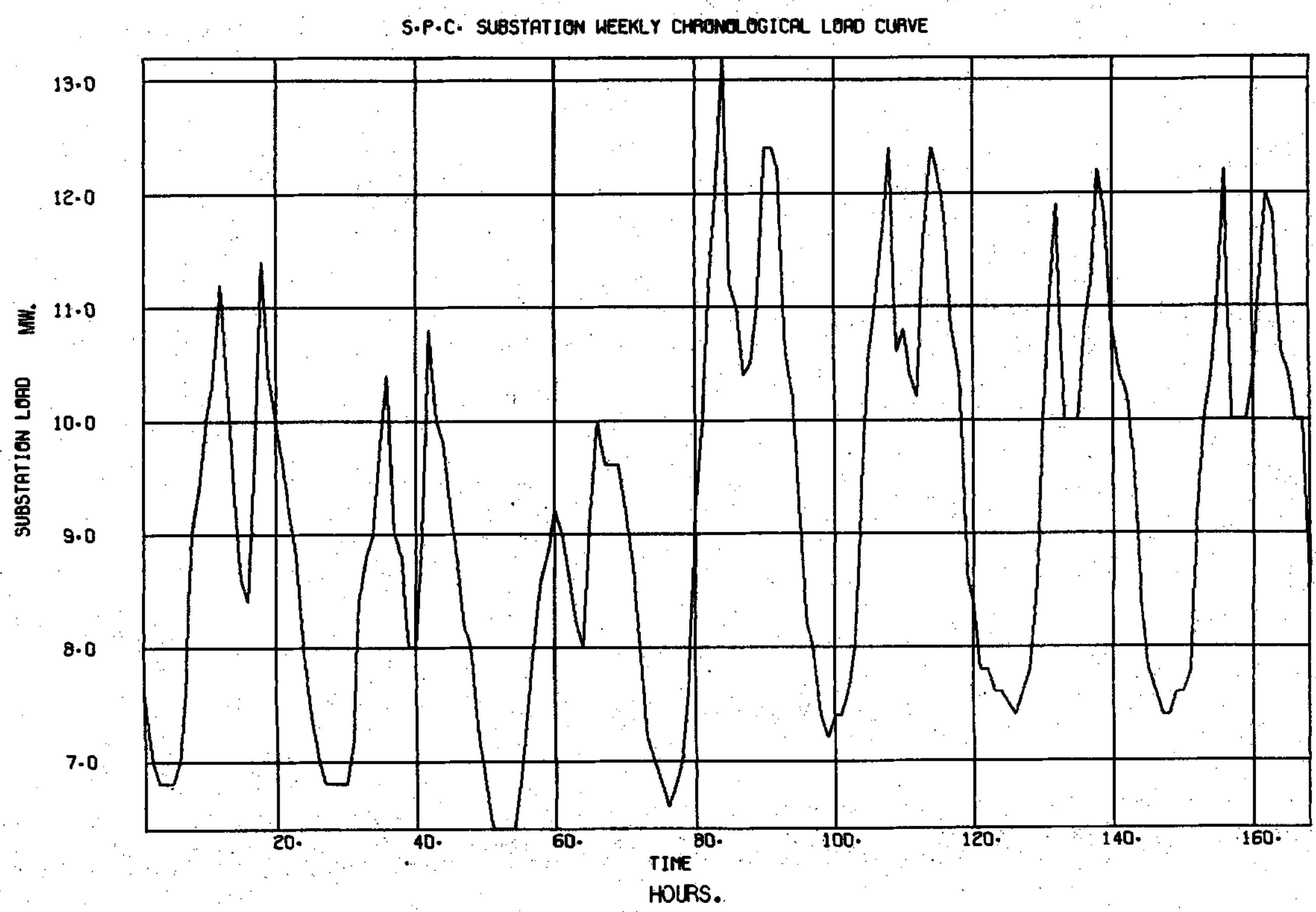


Figure E1 Chronological Load Curve of a Typical S.P.C. Substation.

APPENDIX F

AN ILLUSTRATION OF SYSTEM CUT SETS

A cut set is a set of components which when removed from the system interrupts all connections between the source point and the load point. If all the components in a cut set fail, the system will be failed regardless of the condition of the other components in the system. The system may have a large number of cut sets and a particular component may be in more than one of them. The cut sets for load point A shown in Figure F1 are as follows:

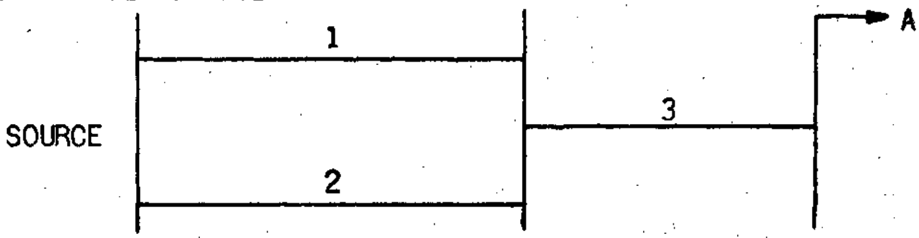


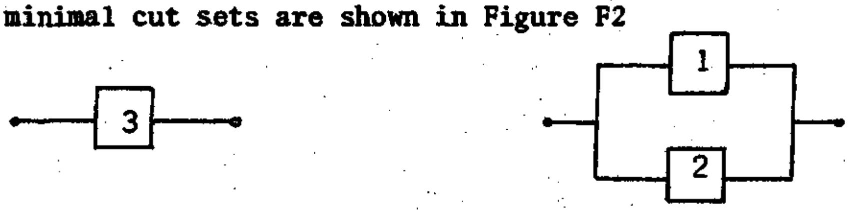
Figure F1: A System for Illustration of Cut Sets

Cut Set	Components in Cut
1	3
2	1,2
3	1,3
4	1,2,3
5	2,3

A minimal cut set is defined as a cut set in which there is no subset of components whose failure alone will cause the system to fail. This implies that a nonminimal cut set corresponds to more component failures than are required to cause system failure. The minimal cut sets for load point A are as follows:

Minimal Cut Set	Components in Minimal Cut Set
1	3
2	1,2

These minimal cut sets are shown in Figure F2



First Order Cut Set

Second Order Cut Set

Figure F2: Minimal Cut Sets for System in Figure F1