APPLICATION OF RELIABILITY WORTH
IN
POWER SYSTEM PLANNING

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UNIVERSITY OF SASKATCHEWAN

Electrical Engineering Abstract

"APPLICATION OF RELIABILITY WORTH IN POWER SYSTEM PLANNING"

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ABSTRACT

In the past two decades there have been increasing pressures and incentives for utilities to optimize their investments and operations and to more adequately justify plant expansions. A major aspect of the justification and optimization of system expansion is cost-benefit assessment of power system reliability. Power system reliability assessment has been a topic of much research and is in common usage by most utilities. The assessment of power system reliability worth is an area of more recent concern but one where a fair degree of attention is focussed. The melding of system reliability indices and worth, the application of reliabilty worth, is an area which has received minimal attention and is addressed as the main emphasis of the thesis.

The thesis presents an overview of reliability worth data and of power system reliability assessment. Considerations and problems associated with the application of reliability worth are discussed for generation, composite and distribution systems. The majority of studies were found to have been performed in the area of generation reliability optimization. The major and more current ones are discussed and compared. Major conclusions are that generation reliability worth assessments result in relative indicators not absolute ones and that interruption cost data do not adequately include the indirect effects of generation type outages. Composite system reliability worth assessment is discussed with the conclusion that application of worth data is presently difficult because of the immature state of composite reliability assessment techniques. The "COMREL" composite reliability program is utilized in an example costing application. The thesis places a strong emphasis on the application of reliabilty worth in distribution system studies. Distribution indices are fairly absolute measures of user reliability. Interruption cost data are most applicable in distribution system studies.

A major contribution of the thesis is the development of a probalistic simulation program which is used to obtain the probability distributions associated with the reliability indices and interruption costs for simple radial distribution systems. Distributions for the Load Point Failure Rate, Outage Duration, and Annual Interruption Time and for the SAIDI, SAIFI, and CAIDI indices are presented. It is found that the use of the average outage duration to calculate interruption costs can, in a significant number of cases, result in large errors as compared with using the entire duration distribution.

The use of the $/KWHR interruption cost coefficient form is compared with the duration specific $/KW form. An analytical technique for constructing load point outage duration distributions is presented and shown to be computationally efficient as compared to the use of simulations.

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1 INTRODUCTION

1.1 Determination of Acceptable Power System Reliability Levels

Power system planners have always had to consider the question: "How reliable should this power system be built?". In the early years of power system development and construction, planners had only one tool to aid them in answering: their professional judgement. As systems increased in size and complexity and as new constraints appeared, planners came to require additional tools although the exercise of judgement continues to be the primary one.

An early approach to answering that basic question in generation reliability planning was to maintain the percentage reserve capacity at a constant value (e.g. 15%). Another early approach was to ensure that the reserve margin was as large as the largest unit on the system. In the 1930's, planners began to consider the use of probability methods when planning their generation capacity requirements. The first significant collection of papers on the use of this tool was published in 1947 (1). Since then the use of probability methods in the evaluation of power system reliability has grown immensely and is now common practice in generation planning (2) as well as transmission and distribution planning (3, 1, 4).

Reliability evaluation generally provides a measure of the ability of a power system to provide an adequate supply of electrical energy (5). By providing answers to the question "How reliable is this power system?", reliability evaluation still does not answer the question of how reliable the system should be. For example, the Loss of Load

Expectation (LOLE) index has been the most popular generation reliability measure. Utilities have most commonly used .1 days/year, or an equivalent, as the criterion for an acceptable LOLE target level. However, this may not be optimal and may never have been optimal. Indeed, many analysts conclude that in general the .1 day/year criterion is probably not economically justifiable and should be reduced (6, 7, 8, 9, 10).

In the past two decades, increased activity of governments, public utility commissions, consumer groups, and environmental groups has resulted in a need for more adequate justification by utilities for new system facilities. Similarily, for financial reasons, the utilities themselves have a greater incentive to optimize system expansion and operation. Factors underlying these tendencies are:

1) increases in energy costs and conservation
2) high interest rates
3) long regulatory and construction lead times for new facilities
4) escalating construction costs
5) increased concern with environmental and social impacts
6) load demand uncertainty.

A major aspect of this justification and optimization of system expansion is the assessment of worth or benefit of power system reliability as compared with the costs of providing the reliability (11). As early as 1938, S.M. Dean considered the assessment of reliability worth (12). He concluded that the ideal theoretical solution is to consider customer needs, complaints, and willingness to pay for reliability but that this approach was, at that time at least, not feasible due to the practical problems in asking customers their willingness to pay. With the exception of some studies in Europe, especially in Sweden (13, 14), there was little published activity until a 1967 IEE conference on the economics of the security of supply (15). The publication which triggered widespread interest in North America is a 1972 IEEE paper by Shipley, Patton, and Denison (6). Surveys by an IEEE committee (16, 17) and theoretical economic studies by Telson (7, 8) stimulated interest further. A research project performed by this author and others contains a comprehensive bibliography that annotates most major publications concerning power system reliability worth (18, 19, 20, 21). A state-of-the-art overview was also prepared and forms the basis of Chapter 2 of this thesis.

1.2 Applications of Reliability Worth

The main interest of this thesis is the application of reliability worth. As suggested above, the primary reason for determining reliability worth is to enable the justification and optimization of system expansion. The main modes of applying the worth data are:

1) Specific worth data used as input into specific expansions decisions, e.g., interruption cost data for the users on a load bus would be used to decide whether extra facilities should be added to enhance reliability of that load bus.
2) Standardized worth values used as input into specific expansion decisions, e.g., it is decided to use a certain value as the worth of reliability for all users. This non-specific but consistent value would be used in expansion decisions.

3) Worth data used to decide on some general policy for future expansion but not used in specific expansion decisions. Reliability worth data could be used to determine target or minimal reliability levels for composite and distribution load points. The data could also be used to decide on specific standards such as the use of one or two transformers in distribution substation configurations.

4) Load shedding policies could be economically optimized on the basis of differing reliability worth for different user types. This application will become increasingly attractive as the ability to discriminate between users increases with new distribution system techniques.

5) Reliability worth information could aid in the mitigation of interruption effects by means other than system reliability and thus reduce the overall costs of interruptions, e.g., emergency measures organization activities could be increased and made more effective, especially for the larger scale interruptions.

Before reliability worth can be used to determine different reliability levels and load shedding priorities for different types of uses, the controversy between equity and economic efficiency must be addressed. One view holds that targeting more load shedding and lower reliability for users with lower reliability worth unfairly penalizes them. For example; should a wealthy residential user experience higher reliability than a poor residential user? Should a company using interruption insensitive technology or back-up systems experience more interruptions than users who have not guarded against interruptions? Of course the other view holds that the immense savings possible by providing differing levels (22) should not be ignored. One option which is increasingly feasible as the new distribution, load management, and billing systems evolve is to establish rate schedules commensurate with user reliability levels and to provide user selectable levels of reliability (18). Such an application could be both equitable and economically efficient. This topic of equity and efficiency will not be addressed in detail in this thesis but must be considered by utilities.

1.3 Thesis Objectives and Structure

The majority of the applications concerning worth of reliability involve three basic aspects: the interruption cost data, the reliability indices, and the methodology for combining the two in an application. Chapter 2 provides an overview of interruption effects and costs and the techniques for determining reliability worth. Chapter 3 provides a brief introduction to generation and composite system reliability while Chapter 4 introduces distribution system indices.

The bulk of attention on power system reliability worth and optimization has been focussed on the generation system because of the advanced state of the art of generation system reliability evaluation and the potentially large savings which could result from optimization of generation reliability. Chapter 3 provides an overview of the more major generation studies and attempts to outline limitations and problems with present techniques. Composite system reliability worth and optimization have been virtually neglected to date because of the immaturity of composite system reliability evaluation. Chapter 3 also discusses the potential problems involved with the application of reliability worth in composite system planning and briefly discusses an example composite system reliability worth study performed using the University of Saskatchewan composite reliability program "COMREL."

Distribution system reliability worth and optimization has been given a fair degree of attention because distribution reliability evaluation results in fairly absolute measures of reliability and because the reliability indices and interruption worth data are amenable to providing relatively good estimates of reliability worth. Because of the present day applicability in distribution system planning and the lack of detailed studies, the thesis emphasis is on distribution system reliability worth. Chapter 4 discusses generally the application of reliability worth to distribution systems and related considerations and problems. A potential problem which is identified for the distribution system application as well as the generation and composite system application, is that conventionally only the average or expected value of indices are determined and considered. Interruption costs often vary nonlinearly with duration. Use of the index average value can result in large errors. Knowledge of the probability distributions associated with the indices can be used to more accurately estimate user interruption costs, to estimate the error inherrent in using average index values, and to more usefully apply the reliability measures themselves. Chapter 5 describes a simulation program devised to obtain the average values and related distributions for the reliability measures and interruption costs of radial systems. The distributions of load point indices, system performance indices, and interruption costs are presented. The interruption costing errors resulting from the use of average index values are investigated. A simple analytical construction technique is presented which can be used to obtain the Load Point Duration distribution with only a small portion of the CPU time required by a simulation program.

2 RELIABILITY WORTH DETERMINATION AND DATA

The objective of this chapter is to provide some background concerning reliability worth data. The presentation in this chapter is based mainly on an overview prepared as part of a CEA research project with which the author was involved (18, 20). Some update has been included.

2.1 Impacts of Interruptions

An initial and necessary step in the determination of the costs of interruptions is the understanding of the impacts, monetary and otherwise, on the customers. Instead of detailing the impacts, the review characterizes them with the importance and the classification of the impacts being emphasized.

The impact on a customer due to a cessation in the electrical supply depends greatly on the customer, the type of customer (e.g., industrial or residential), what function the electricity performs (e.g., space heating, lighting, motor drive, or computers), and on the attitude of the customer. Also acting to determine the impacts are the characteristics of the interruption: the time of day, week, or year, the amount of advance warning, the frequency of occurrence, the physical extent of the interruption, and others. Factors such as outside temperature or the occurrence of the interruption during special events all affect the impact.

An interruption of an industrial customer could result in lost production, damaged equipment, spoilt materials, poor quality final product, or health hazards. Commercial customers could suffer a loss in sales, damage to stock, or health hazards to employees and customers. Interruptions to public service and educational institutions could result in loss of production, poor quality service, or health hazards. Emergency and corrective agencies with interruption to their power, may not be able to perform their functions, resulting in a serious hazard to the employees, public, or in the case of retention facilities, to the inmates. Health institutions have many life saving functions critically dependent on a continuous electric supply. Interruptions to residential customers are often thought to have negligible impact but long interruptions can cause monetary losses such as food spoilage or damage due to adverse temperatures; for shorter interruptions the inconvenience caused by loss of leisure time, food preparation and housekeeping capabilities is significant. Myers (23, 24), Telson (7), and Corwin and Miles (25) discuss these impacts in detail.

All the possible individual impacts cannot be considered, especially in the context of power system planning, due to the overwhelming numbers and differences involved. A classification scheme must be employed to allow for impacts to be considered in groups with similar characteristics.

The most distinctive characteristic is whether the impact is a direct or an indirect impact. Direct impacts are those resulting from the cessation of supply while indirect ones result from a response to the cessation. Direct impacts can be further separated into economic and social impacts. Direct economic impacts could be lost production, food spoilage, and utility costs. Direct social impacts could be inconvenience due to lack of transportation, uncomfortable building temperatures, or loss of leisure time. Most direct impacts are relatively predictable with the economic effects being quantifiable in monetary terms.

Indirect impacts can be further divided into economic, social, and organizational impacts. Indirect economic effects are those that result from the synergistic interplay between economic units (e.g., factory B production being reduced because factory A was interrupted yesterday) and from other factors such as possible tendency for firms to relocate. Indirect social impacts could include social disorder, rioting, or vandalism. In the New York Blackout of 1977 over 200 million dollars of costs resulted from this impact alone. Organizational impacts include the alteration in plans and procedures of emergency organizations or of organizations affected by the interruption. A comprehensive analysis of these and other possible categorizations and impacts is contained in the study of the New York blackout by Corwin and Miles (25). Another important indirect response is the long term adaptation of customers to interruptions. As discussed by Myers (23, 24) and others, this adaptation would tend to decrease the long term costs due to the mitigation of the impacts; however this adaptation involves a cost in redirected resources and effort.

Direct impacts are relatively easy to determine and are consistent. Indirect economic and social impacts are much more difficult to determine and are much less consistent. The blackout in New York in 1965 resulted in relatively little damage due to social disorder unlike the 1977 one, showing the inconsistency in these types of impacts. In spite of the difficulties, indirect and social impacts cannot be ignored as they can even be much greater than the direct ones (e.g., the 1977 New York blackout study (25) reported that the indirect costs were at least 290 million dollars while the direct costs at least 55 million dollars).

Knowledge of the impacts resulting from interruptions is necessary to determine the costs associated with unreliable power systems and to determine the most effective schemes to reduce and mitigate the effects. The degree to which power systems should be made reliable must be compared against the effectiveness of other means to reduce the impacts. Direct impacts may be best reduced by improved system reliability while indirect effects may best be reduced by emergency measures planning and preparation.

2.2 Determination of the Customer Costs of Interruptions

Methods to determine the customer costs of interruptions are discussed under the following headings. Surveys of customers are discussed last for the sake of convenience.

1) Price of Electricity
2) Implicit Valuation of Reliability Used in the Past
3) Gross Economic Indices
4) Price Elasticity
5) Customer Subscription
6) Blackout Impact Studies
7) Customer Surveys

2.2.1 Price of Electricity

An intial response to the question of how much does an interruption cost is that the loss equals the price of the electrical energy not supplied. This approach is not economically or practically sound because the value of a product is not necessarily the price of the product. The product price itself depends on the available supply. In that sense, since the supply is non-existent during an interruption, an alternate supply could be priced much higher than the normal price, if one was available. A chemical plant which loses a day's production of product worth $100,000 for a 10 minute interruption would value the electricity not supplied at much more than its nominal price of a few dollars. A more reasonable approach would be to use the price of electricity as a lower bound estimate of the cost (26).

2.2.2 Implicit Valuation of Reliability Used in the Past

This approach is based on the principal assumption that society and individuals have determined, by means of experience, acceptable levels of reliability related to the cost of electricity and expenditure by the utilities. This empirical approach is based on a more general one suggested for use in the determination of social preferences by Starr (27). In this approach the historical level of interruptions and the historic expenditures on reliability are compared, yielding some estimate of the costs per KWHR unsupplied. While data are available for such a calculation, the approach suffers from two main problems:

1) historic levels of reliability may not have been optimally established,

2) valuations change with time, i.e., what was once acceptable may no longer be acceptable.

2.2.3 Gross Economic Indices

Many attempts at determining the interruption costs are based on the use of a ratio of gross economic measure (e.g., GNP) and a suitable energy consumption to yield a figure (e.g, $/KWHR), which is assumed to be the cost of unsupplied energy during interruptions. Shipley, et al. (6) divided the USA GNP for 1967 by the total national electrical energy consumption. This estimate of $.60/KWHR is multiplied by the estimated energy not supplied due to all system interruptions and compared with the total expenditures on generation, transmission, and distribution, with the conclusion that the reliability is greater than economically justifiable. Telson (7, 8), considers the GNP divided by the non-residential energy consumption to be an upper bound for the costs. Telson also considers a more reasonable upper bound to be the wages paid divided by non-residential energy consumption. For New York, this results in an estimate of $1.22/KWHR and for the USA $.57/KWHR. Many other studies obtain similar results when using the above approach or other methods such as value added/KWHR.

Shipley's and Telson's application of the cost figures are fundamentally different: Shipley uses statistics concerning the actual occurrences of interruptions for one year while Telson uses the predicted occurrence of interruptions in only the generation system for a number of years. Both use the same approach in estimating the costs and arrive at the same conclusion, namely that present system reliability is too high.

The use of this approach is supported by the following arguments:

1) Not all of the GNP would cease during an interruption.

2) Some production can be made up once the supply is restored.

3) Residential energy consumption contributes little economically and would tend to lower the average cost/KWHR.

4) Interruption cost/KWHR increases with the duration of interruption. Since most interruptions are of short duration, the figures would be overestimates.

The studies recognize that for some firms the loss could be greater than that assumed due to damaged equipment or spoiled product. This factor is assumed to be compensated for by the above factors.

There is little evidence supporting the assumption of a linear relationship between the gross measures and energy not supplied. While aggregating the cost over many customers within a region will tend to average out the variations among customers, the GNP/KWHR figure may not be a good estimator of the true average. The factors causing an overestimate may not be equally compensated by the factors causing underestimation. This gross aggregation is a disadvantage in that the estimates cannot be applied to a specific consumer type or region.

As has been pointed out by Samsa (28), surveys of customer costs indicate that argument 4) listed above concerning the increase in cost/KWHR with duration is erroneous: the cost/KWHR tends to decrease with duration. Thus the GNP/KWHR estimates would underestimate the cost.

An inherent problem with this approach is that gross economic measures do not take into account indirect economic or social effects.

These indices measure economic activity, they are not a comprehensive or adequate measure of societal valuation.

Another problem is that the cost/KWHR form itself may result in error. This is discussed in detail in Section 5.6.

2.2.4 Price Elasticity

The use of average price elasticity of the demand for electricity as a means to obtain the loss in consumer welfare due to interruptions has been discussed by Myers (23), Higgins (29), Webb (26), Shew (30), and others. This approach would result in an economically sound measurement of the costs, especially for residential consumers for whom the cost is difficult to ascertain. The currently available estimates of customer price elasticity are unfortunately inappropriate for this purpose; they are for long run changes in the customer demand rather than the very short term needed in these studies. The use of price elasticities does not take into account the unexpected nature of the interruptions.

2.2.5 Customer Subscription

Nordin (31) suggests a scheme in which customers would subscribe and pay for the amount of peak reserve capacity they desire; during capacity shortages these customers would have priority in being supplied before non-subscribers. As discussed in the bibliography, this method would not result in optimum reliability choices and is impractical. The concept of relying on customer actions and decisions as a means of communicating their preferences and thus determining the target levels of supply reliability would be attractive only if some acceptable and practical means of doing so could be devised. This concept is similar to insurance type schemes discussed in the Swedish Customer Interruption Cost survey report (14) and by Higgins of Ontario Hydro in personal communication. The Swedes found that customers were not particularly interested in such a scheme.

2.2.6 Blackout Impact Studies

The above approaches employ indirect means to determine the costs of interruptions. A more direct approach is to investigate the effects of interruptions that have actually occurred. In this way assumptions can be avoided.

An interruption which has been studied most extensively is the 1977 New York City blackout. Two major investigations (25, 32) of the effects have been undertaken as well as lesser ones. The Library of Congress study provides little information, relying heavily on secondary sources and variations in gross business activity measures. The study prepared by Corwin and Miles provides detailed information on the effects as well as proposing a categorization scheme discussed earlier. These studies do not provide information which could be used to derive an estimate of the costs of future interruptions.

A few reports have discussed the effects of other blackouts but have not provided suitable interruption cost figures (30, 33, 34, 35). Studies into the effects of smaller interruptions such as would be caused by distribution outages have not been undertaken due to the difficulty of obtaining information on the relatively small effects.

Attempts to do so would resemble customer surveys. A set of impact studies by Jack Faucette Associates which use surveys will be discussed in the following section (36, 37, 38).

Blackout impact studies can provide qualitative information necessary in the determination of the effects of interruptions. The quantitative information is useful for the same reasons but does not provide cost figures that can be used to estimate the costs of interruptions in general.

2.2.7 Customer Surveys

A less direct method to determine the costs of interruptions than a blackout impact study is the survey of customers concerning their estimates of the impacts and their preferences. The surveys have been of three types, each enquiring of the customer one or more of the following aspects:

a) monetary losses sustained by the customer,

b) customer willingness to pay for aversion of interruptions,

c) perceptions of the customers concerning the quality of life and environment as affected by interruptions.

The first two involve the determination of monetary estimates of the impacts while the third attempts to determine non-monetary measures of the quality of life.

The first extensive survey attempting to determine monetary estimates of the impacts is the Swedish survey in 1969 (14). Industrial customers were surveyed directly while estimates of the costs to residential, commercial, and other sectors were determined by means of discussions with representative groups and worked examples. Estimates were reported as $/KW and $/KWHR for various durations of interruptions. Residential costs were reported to be even greater than industrial costs but this conclusion is dubious in the light of the different approaches used for the two sectors.

In 1974 the IEEE sponsored a series of surveys (16) of the costs of interruptions to industrial plants in the USA and Canada. Estimates were reported as $/KW peak demand and $/KWHR without any specific consideration of the duration of the interruption. The effect of frequency is taken into account by the first figure but cost is assumed to increase in a linear fashion with duration. The times required to restart plants after complete stoppage was quite long (median of 4 hours) and the critical duration before production would be seriously effected was very short (median of 10 seconds). The costs, restart times, and critical loss durations were reported to vary greatly between customers. Small plants were reported to have greater cost than large plants.

More recently, Ontario Hydro has carried out an extensive series of surveys of the impacts of interruptions to the customer sectors. Large users, small industrial, agricultural, retail commercial, institutional, and office building customers were surveyed for their losses incurred with various durations of interruptions (39 - 46). The effect of time of day, week, and year, of advance warning, and standby generation was investigated. The surveys also investigated many other characteristics of the customers and their sensitivity to interruptions. The estimates were reported as $/KW peak demand as a function of duration.

A most significant conclusion is that the cost varied with customer and with category by orders of magnitude. For this reason, the customers are further divided into subcategories based on their activity and their usage of electricity. As the IEEE survey indicated, small industrial costs were greater than large industrial costs. For short and medium durations, the commercial costs were much lower.

The Ontario Hydro Large Users Survey report depicts the rate of change of interruption cost with duration for large users. The cost estimates saturate at approximately $.65/KWHR. This value is roughly equivalent to the values for all customers aggregated, derived by use of the gross economic indices. These results indicate that the assumption made of the gross economic estimates being conservative is erroneous since the cost/KWHR is greater for short interruptions, not less. See also Section 2.2.3 above.

Ontario Hydro has also surveyed the residential market to obtain estimates of customer willingness to pay to avoid interruptions (40). The resultant estimates ($.03/KW for 1 hour interruptions) appear to be quite low. Repeat surveys have resulted in similar results. As discussed in a CEA research report (18, 19) these estimates may be realistic but there are some factors which could have adversely affected the validity of the results.

Munasinghe (47) presents a methodology for measuring residential interruption willingness to pay and reports results of some interview surveys in Brazil. The main cost is hypothesized to be the loss of evening leisure time which was evaluated at the household earning rate. Certain assumptions made in the approach apply to developing countries rather than developed countries such as Canada. Because of this and other factors the results are not directly comparable.

Bhavaraju and Billinton (48) point out that the presently available data derived from surveys is only applicable to local random interruptions rather than large wide scale ones; i.e. distribution rather than generation interruptions. The survey estimates do not take into account indirect economic and social effects which would tend to be significant for the large interruptions. The Ontario Hydro generation expansion study, SEPR (10), takes this partially into account by using macroeconomic models to determine indirect economic costs in addition to the customer survey estimates of direct effects.

General Public Utilities has surveyed customers to obtain their psychological perception of the impact of interruptions (28). GPU's intention was to correlate these results with sociological indicators of the degree of well being of the public but this may be impractical.

A set of impact studies that was performed by Jack Faucett Associates has made a significant contribution to costing methodology and provides interruption cost estimates (36, 37, 38). The methodology uses as the measure of interruption cost the willingness-to-pay to avoid the interruptions or rationing during capacity or energy shortages. Users affected are grouped into four categories: producers, employees, consumers, and the general public. Surveys are used to elicit the information. The effects of a natural gas shortage in the U.S.A. in 1976-77 and an electrical capacity shortage in Florida in 1978 are studied. As is typical for case studies, the results cannot in general be used to predict interruption costs because the results are limited to situations with the same set of characteristics as the one studied. The methodology however can be utilized in a more general survey. The questionnaires themselves would need to be drastically revamped to put them into a predictive setting and to include a collection of scenarios.

A CEA research project that the author was extensively involved in, developed a methodology and a set of questionnaires which were used to perform an extensive survey of users (18). Because of rate related hostilities and user suspicions, willingness-to-pay was not used as the main measure of interruption cost. It was decided that as in the Ontario Hydro surveys, non-residential users could adequately estimate their losses without reference to rate increases. Residential users could not provide a simple loss or worth estimate. A methodology related to the costs of actions that residential users predicted they would take in preparation for interruptions was developed to estimate costs. Rate related estimates were also utilized. Figure 2.1 depicts cost estimates obtained for winter peak day interruptions. Table 2.1 presents the availability of Ontario Hydro and University of Saskatchewan (CEA Research Project) data and questionnaires for a breakdown of all user groups. The Ontario Hydro and University of Saskatchewan data tended to be in agreement with the notable exception of the residential sector for which the University of Saskatchewan project resulted in significantly higher cost estimates.

Figure 2.1 Comparison of Sector Interruption Cost Estimates ($/KW)

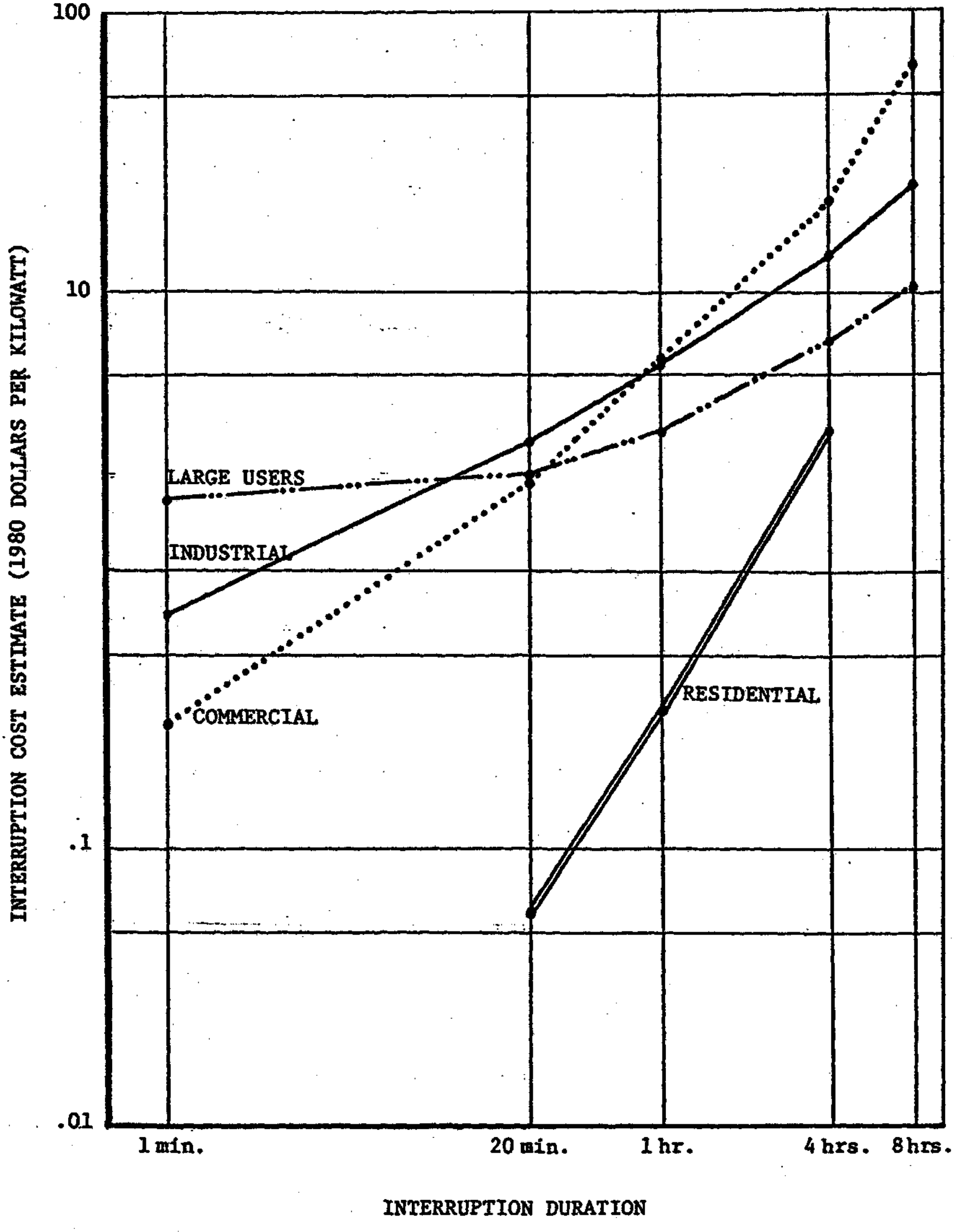


Table 2.1 Availability of Interruption Cost Data

User Groups	SIC Categories	Manitoba Hydro Consumption GWHR (%)	Applicable Data	Applicable Questionnaires
Bulk - Large Users		1200 (12.5%)	Data not directly useable	U. of S. OH
Residential		2999 (31.2%)	U. of S. OH	U. of S. OH
Agriculture - small farms	3-21	1000 (10.4%)	no data	OH
- large farms (>50 KVA)	3-21	123 (1.3%)	OH	OH
Forestry and Mines	31-99	220 (2.3%)	U. of S.	U. of S.
Manufacturing	101-399	1425 (14.8%)	OH	OH
Construction	401-421	86 (.9%)	no data	U. of S & OH industrial
Wholesale Trade	602-629	130 (1.4%)	no data	U. of S. & OH commercial
Retail Trade & Services	631-699 841-899	735 (7.7%)	U. of S. OH	U. of S. OH
Real Estate Operators	737	66 (.7%)	OH	OH Office Bldgs.
Transportation & Storage Communication Utilities Finance & Insurance Education Health and Welfare Public Administration Sub-total	501-527 543-549 572-579 701-735 801-809 821-831 902-991	455 42 68 45 309 188 261 1368 (14.3%)	OH	OH Gov't. & Industrial
Miscellaneous eg. Street Lighting, Cottages, unmetered		250 (2.6%)	no data	no questionnaire
Total		9602 (100%)		

3 GENERATION AND COMPOSITE SYSTEM RELIABILITY WORTH

In reliability studies the generation system is usually comprised of the total generating capacity with no consideration of the associated transmission or distribution facilities. The main exception to this occurs in interconnected system studies wherein the tie line capacities and availabilities are usually included. This includes situations such as studies of the Manitoba system which must include the effect of the HVDC ties in non-interconnected generation studies.

Transmission systems can be functionally divided into two categories: those including the actual generating facilities and those which can be decoupled from generation facilities and treated as series, parallel or simple networked configurations (5). The first category can be designated as bulk power facilities and the problem of assessing the adequacy of the combined generation and transmission elements designated as composite system adequacy evaluation (4). The second category can be designated as sub-transmission facilities and in this thesis is considered to be part of the distribution system. Studies of terminal stations and substations can also be considered to be part of the distribution system except when they are studied as part of the bulk power transmission system in which case the study would be a composite system study.

The next section considers the evaluation of generation and composite systems reliability. The following sections consider the application of reliabilty worth.

3.1 Generation and Composite Reliability Indices

Power system reliability can be considered to consist of two aspects: system adequacy and system security. Adequacy is defined as relating to the existence of sufficient facilities within the system to satisfy the customer load demand while security is defined as relating to the ability of the system to respond to disturbances within that system (5). Reliability studies and indices have for the most part been concerned with the static aspect of power systems: system adequacy. Probabilistic methods to assess system security have recently begun to be developed but are still very much in their infancy. For this reason the thesis only considers adequacy indices.

The present generation and composite reliabilty indices are relative rather than absolute measures of system reliability because they do not sufficiently and faithfully take into account factors such as system security considerations, load uncertainty, reliability data distributions and errors, and system complexity (5, 48). Because of the form and the lack of completeness, the generation indices are more of a relative and less an absolute measure than composite indices. The indices do provide an essential and good indicator of system adequacy variation with parameters of interest such as load growth or system capacity. The indices do not provide an absolute measure of the interruptions associated with the generation and transmission systems and experienced by the users. Interruption costs calculated using these measures can not then be absolute or even reliable measures.

In generation studies, the system can be simply modelled as in Fig. 3.1.

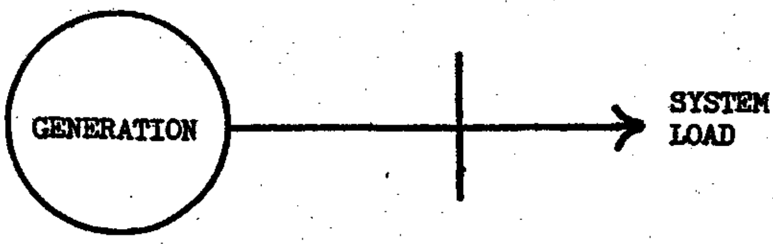


Figure 3.1 Generation System and Load

The basic approach is to form a generation capacity model and a load model and then combine them (4). The capacity model uses information such as generation unit capacities, outage rates, repair rates, unit derating, maintenance outages, water flow or fuel availability, and other factors to produce a generation capacity unavailability table or model. The model of system load can take on the form of peak curves, hourly load duration curves, or more dynamic Markovian type models. The Loss of Load Expectation (LOLE), Loss of Load Probability (LOLP), and the Loss of Energy Expectation (LOEE) indices are obtained by combining the capacity outage table with the load curve. The Frequency and Duration indices are obtained by combining a frequency and probability of outage capacity state table with a load model. Most utilities use the LOLE and LOEE as their main generation indices and only some utilities supplement them with the F & D indices. The LOLE and LOEE Indices have the advantage of requiring only a moderate amount of data and computation and of being able to provide easily a measure of energy not supplied. The F & D indices have the advantage of providing more information concerning the system reliability. Monte Carlo simulations of the generation system are also performed and have the advantage of more flexibility in modelling and of yielding more reliability information but the disadvantage of requiring a great deal of computation. The indices can be summarized as in Table 3.1 (5):

Table 3.1 Standard Techniques and Indices for Generation Capacity Evaluation

Method	Indices
Loss of Load Expectation (LOLE) (Loss of Load Probability LOLP is sometimes used)	Expected number of days (hours) in the period that the daily peak load (hourly load) exceeds the available capacity.
Loss of Energy Expectation (LOEE)	Expected load energy curtailed or not supplied during the designated period.
Frequency and Duration (F & D)	Expected frequency, probability and duration of distinct generation-load margin states during the designated period.
Monte Carlo or Simulation	All of the above indices plus distributional information.

Composite generation-transmission reliability assessment is a relatively recent phenomenon and is still evolving into a mature technology (49 - 55). The main difference between the composite and generation techniques is that transmission line capacities and unavailabilities are included in the composite techniques. Because simple continuity modelling is inadequate some form of transmission line loading evaluation such as load flow analysis is usually integral in the composite reliability studies. Criteria for acceptable bus voltage levels, selective load curtailment, generation rescheduling, common mode outages, and station or protection failures are aspects of the present techniques. Two main types of indices are computed: system wide indices and bulk load point indices.

A set of techniques and computer program for performing composite reliability assessment has been developed at the University of Saskatchewan (52, 53, 54, 55). The program, "COMREL", simulates the outage states of the combined generation and transmission system model and performs an AC load flow analysis for each contingency. If the loads cannot be supplied without overloading the lines, a decoupled line overload alleviation technique is used to determine a new generation schedule and the need for shedding bus loads. Because the computational requirements of considering multiple outages for even small system models is large, the program uses the Fast Decoupled Load Flow and sparse matrix techniques for computational efficiency. While the earlier versions of the program consider only sets of independent line and generation outages, recent versions consider common mode and station related outages in order to perform a more faithful simulation of the system and obviate the need to consider more than second order independent outages.

Indices have been calculated for medium sized practical configurations such as a 30 bus, 56 line model of the SPC system. The major indices are listed in Table 3.2.

Table 3.2 Composite System Indices

Load Point Indices

Probability of Failure
Expected Frequency of Failure
Expected Duration of Failure
Expected Number of Voltage Violations
Expected Number of Load Curtailments
Expected Load Curtailed
Expected Energy Not Supplied

System Indices

Bulk Power Interruption Index (MW/MW-yr)
Bulk Power Energy Curtailment Index (MWhr/yr)
Bulk Power Supply Average MW Curtailment Index (MW/Disturbance)
Energy Index of Unreliability Including Transmission
Severity Index (System Minutes)

3.2 Generation System Reliability Worth

There are three basic aspects to determining the worth of generation system relability: the reliability indices, the interruption cost data, and the methodology for combining the two in an application. The indices are discussed in the previous section while the cost data and underlying theory are discussed in Chapter 2. This section discusses the methodology associated with some of the more significant attempts that have been made to assess generation reliability worth.

A general comment that applies to all the specific approaches is that the presently available interruption cost data is less applicable in generation system studies than in distribution system studies (48). Interruptions due to generation shortages tend to be widespread and of long duration as opposed to distribution induced interruptions which are more localized, random, and probably shorter duration. Large widespread interruptions can result in a large amount of indirect effect which is not adequately included in the present cost data.

One of the first attempts to assess and compare power system reliability cost and worth is the paper by Shipley, et al. (6) and is not strictly related to generation reliability because it is concerned with the past historical reliability performance of the entire system rather than the predicted reliability of the generation system. It is included because it initiated the public discussion on this topic. In it the total energy-not-supplied in the USA is estimated from public records of bulk supply disturbances and an estimate that the unavailability of distribution was four times that of the bulk system. This is multiplied by an interruption cost estimate of $.60/KWHR and compared with the total expenditures on generation, transmission, and distribution for that year. The study concluded that the reliability was greater than economically justifiable. While interesting and provocative, this conclusion cannot be readily accepted because of the admitted crudeness of the reliability estimate and the inadequacy of global estimates of interruption cost which has already been discussed in Chapter 2.

Of the generation reliabilty indices, LOLE (and LOLP) is the most widely used but unfortunately it is often misapplied. While useful as a relative indicator of adequacy, it is not related to the physical consequence of interruptions and should not be used to obtain even relative predictions of the costs due to interruptions.

An example of the misuse of LOLP is a study of the power supply in New York by Kaufman (9). In it, LOLP and various assumptions are used in an attempt to calculate the system interruption costs for various LOLP levels with the conclusion that the system is built too reliable. Target LOLP levels and the judgement of utility engineers are used to estimate the frequency, probability, and magnitude of interruptions. The resultant KWHR-not-supplied estimate has little valid basis. This estimate is combined with a global interruption cost estimate (value added/KWHR) in a rigorous cost-benefit analysis. The conclusion that the system is built too reliable is also one that obviously cannot be trusted.

LOEE (and LOEP) is another popular index and it, as a measure of unsupplied energy, bears more relationship than LOLP does to the interruption impacts on users. It does not give the frequency or duration of interruptions and is still very much a relative indicator of adequacy. This index cannot be used for making an absolute estimate of interruption costs but can be used in conjunction with global $/KWHR data to obtain a <u>relative indicator</u> of costs. Again this limitation is often not recognized. Telson, in a much quoted publication (7) studies the economics of power supply reliability. Like Kaufman, he concludes that power systems are built much too reliable. Telson uses a Monte Carlo simulation program to study several optimized expansion plans of a system based on the New York Power Pool (NYPP). He derives relationships between LOEP (Loss of Energy Probability), LOLP, expansion costs, and interruption costs. He concludes that for systems such as NYPP the economically optimum LOLP criterion is in the order of 100 days in 10 years instead of the commonly used 1 day in 10 years. Samsa, in his excellent critique of Telson's study, determines several technical and assumptional errors (28). The corrected results indicate that present generation system reliability is only ten times greater than the optimum instead of one hundred times as the original results indicated. In another study Telson uses a slightly different approach based on the reduction of unsupplied energy due to marginal additions of generating capacity (8). His conclusions are similar to the ones obtained in his earlier but corrected work. While both studies further the understanding of reliability optimization, they are limited by ultimately being based on LOLP and global measures of interruption cost.

Shew also estimates energy-not-supplied from LOLP and uses global interruption cost measures (30). A contribution of his work is the use of an optimal mix of user rationing and lowered reserve levels to handle situations of insufficient capacity. This is a significnt step away from the more crude approach of simply multiplying a $/KWHR factor with the total energy-not-supplied. In operating a generation system, capacity shortages can be dealt with by a combination of many procedures, each with its own associated effects and costs. Planned user rationing and allowing lower reserve levels (and the consequent unplanned interruptions) are two of these emergency operating procedures.

A sophisticated approach involving LOLP and optimal expansion plans is reported by Sanghvi et al. (56, 57). System reliability is considered to consist of peak and strategic reliability. Peak reliability is defined as the ability of a power system to meet peak load. Strategic reliability is defined as the ability of the power system to withstand uncertain extended disruptions such as fuel supply shortages or unexpected load growths. Such a differentiation may prove useful but the concepts associated with strategic reliability can be incorporated with the conventional reliability indices.

Sanghvis' approach consists of a linear programming optimization model used to choose expansion plans that cost-effectively provide appropriate levels of strategic and peak reliability. The probabilities of uncertainty factors such as fuel supply availabilities and load growth rates are explicit inputs. Capital, operating, and interruption costs are computed and compared for each plan and scenario. The least cost expansion plan is thus determined. Global interruption cost estimates ($/KWHR) are used and are adjusted to be a non-linear function of the energy-not-supplied. In each run of the program, the peak reliability is not optimized but is limited to being no less than an inputted constraint. LOLP is not calculated for each year. With a "bootstrap" technique, the changes in LOLP from one year to the next are estimated as a function of changes in capacity and peak load. While such an arrangement has a significant advantage of relatively low computing costs, there is loss of accuracy in the LOLP calculation.

The frequency and duration indices are more physically significant than LOLE or LOEE but are still relative indicators of reliability. Either global cost data ($/KWHR) or user-duration specific data can be used in conjunction with these indices. The user-duration data seems more appropriate than the $/KWHR data because information about expected outage duration is available and many studies have indicated that cost is not linearily related to duration.

The application of user-specific data is made somewhat difficult by the fact that in generation adequacy evaluation little information concerning which customers are interrupted is available. Often it is assumed that customers are interrupted equally but a more reasonable approach is to determine the relative likelihoods from system history.

There have been many suggestions that utilities should make known the priorities they place on which classes of users are shed during periods of under capacity and how these priorities are determined (7, 11, 28, 58, 59, 60, 22, 36, 37, 38). These suggestions mainly emphasize that the use of interruption cost information to establish load shedding priorities would result in an economically more efficient operation. However, the setting of priorities would also need to consider non-economical factors such as the needs of hospitals and other institutions. Another consideration is that it may be deemed inequitable to shed residential loads in favour of industrial or commercial loads. Rate compensation may be needed to ensure equitability. The application of interruption cost data in the determination of load shedding policies will become more important in actual system operation and in reliability worth studies because of the potentially large cost savings to society that have been shown to occur (22).

Another problem with the application in generation system studies of presently available interruption cost data is that indirect effects and costs tend to be excluded. The indirect costs can be many times greater than the direct costs (18) but can and have been involved in system studies by the use of macroeconomic techniques (10, 36, 37, 38).

An excellent study which uses F & D indices was performed by Ontario Hydro in a comprehensive assessment of its generation system expansion plans (10). This study was an application of the practical state of the art in generation reliability assessment and an advance in the state of the art of reliability worth assessment.

The effect on the people and province of Ontario, and Ontario Hydro of changes in load growth, nuclear-coal capacity mix, generating unit size and amount of reserve generation capacity is investigated. The effects studied include utility financing requirements, capital availability, cost of electric power, social-economic effects and environmental effects. The costs of interruptions to customers, as determined from a most extensive set of Ontario Hydro surveys, is used to estimate the impact of interruptions. Generation reliability is evaluated using the Frequency and Duration method with uncertainty of load forecast and equipment additions included as well as many other factors. Interconnected system assistance is not considered. Although transmission and distribution reliability is evaluated and incorporated in the costing procedure, variation in their reliability is not considered.

The amount of load shedding (1 hour rotating cutoffs) and the amount of partial load reduction (interruptible and managed load cutting, voltage reduction, voluntary industrial load reduction, and voluntary public load reduction) is evaluated as a function of target generation reserve levels. The study attempts to deal with uncertainty in reserve by calculating the emergency measure frequency for the worst to the best years in ten yearly increments.

The optimum balancing of costs and benefits of generation reliability indicates that the target reserve level could be 3 to 7 percentage points less than the present 30% resulting from use of the LOLP criterion of 1 day/2400. The total cost of electricity, including interruption costs, would be reduced by as much as 2% if the reduced reserve level were used.

A most significant conclusion for the application of customer cost estimates is the relative lack of sensitivity of the optimum reserve level or the total system cost to variation in the cost estimates. It has been acknowledged that there is great uncertainty in the cost estimates; but that sensitivity studies and the flatness of the total cost curve in the optimum region prevents the uncertainty from significantly decreasing the confidence in the results. As will be discussed later, studies have shown that the flatness of the curve and sensitivity to cost estimate errors varies with the type of system being studied (61).

The expected number of interruptions to customers is not determined. The reliability assessment only considered the generation system, separate from the transmission and distribution system. Thus, customer load point reliability is not assessed. The 1 hour rotating load shedding scheme is only an approximation to actual system operation. The Frequency and Duration technique, while being the practical state of the art is a relative measure not an absolute measure of reliability. It should be recognized that the use of generation adequacy evaluation and interruption cost data yields estimates of system interruption cost which, while quite useful, can only be assumed to be reasonable.

In a book by Khatib (62), generation adequacy assessment, marginal cost of reliability, and the marginal worth of reliability are investigated. He employs F & D reliability techniques and $/KWHR interruption cost estimates. A few of his suggestions are of specific interest. One is his attempt to include time of day variation in the reliability worth assessment. As has been shown (18), his approach of using demand variation as an indicator of interruption cost variation is not a viable one. He develops the concept of a composite reliability index which can be used to aggregate interruptions of the generation system with the transmissions and distribution system in order to enable an efficient optimization of the combined power system reliability. While such an ability would be extremely valuable, much research must first be performed into the equivalence of reliability indices and interruption cost measures for the different system levels and into appropriate aggregating multipliers.

Recent interest in optimizing the USA power system has stimulated much research. One project sponsored by the National Electric Reliability Study developed and applied a procedure for use in power system reliability worth evaluation (22). Important improvements incorporated in this procedure are that the variation of interruption cost by duration, user type, on peak and off peak part of the day, and season is included in the cost estimation and that emergency operating procedures (EOP) are modelled. Whereas the earlier approach of Shew (30) considers two procedures: rationing and interruptions, this project by Poore, et al. considered a broader and more comprehensive set of procedures.

The first step in the approach is to perform a fairly conventional calculation of the frequency and duration of the exact reserve margin states for defined on and off peak periods in the day and for each season. The modelling of the system can be as complex as is required because the procedure is not limited to being performed by any particular F & D program. The utility must then compose a suitable list of EOP and the anticipated load relief for each one. Table 3.3 lists the EOP used in the quoted study.

Table 3.3 Emergency Operating Procedures Used in Poore's Study

Number	Procedure	MW Relief
1	Curtail nonessential utility system load	50
2	Industrial/public appeal for reduced consumption	50
3	5% system voltage reduction	50
4	Curtail interruptible contract load	50
5	Utilize customer generation not covered by contract	50
6	Generation increase to emergency full load	50
7	Obtain capacity from interconnected systems (interties)	50
8	Load Interruption	A

A = Balance of deficiency.

The third step is to determine the curtailment strategies in the event that load interruptions are to take place. The priorities as to which users are to be interrupted must be established. Also to be determined is whether rolling blackouts are to be used and the associated durations. The fourth step is to determine the interruption cost estimates or coefficients to be used for each EOP, each user class, each season, and each on peak off peak day period. The last step is to compute the total cost for the given set of conditions.

This technique was applied to four representative regions in the USA. A major finding was that if the curtailment strategy was to give preference to residential users and interrupt industrial or commercial users, the calculated interruption costs approach the supply costs at reserve margins just below 10%. However, if the curtailment strategy is to interrupt the users in an economically efficient fashion (ie. the low cost residential users first), then the total interruption costs are much lower. It was concluded that cost effective interruption strategies have great potential for lowering the societal cost associated with the electrical supply system.

Decision Focus has developed under EPRI contract a methodology and computer program which estimates the cost to consumers of interruptions and utility rates as a function of planning reserve margin (63, 64, 61). This method takes into account uncertainty of demand, plant addition lead times, cost of interruptions, and environmental and economic impacts of generating capacity additions. These studies are based on the use of decision trees in which the probabilities and customer interruption cost coefficients are assigned by the utilities. System reliability is not computed analytically but obtained from simulations. The probabilities and costs of EOP are calculated. Because only energy-not-supplied is calculated, the variation in interruption cost due to frequency, duration, or magnitude of interruptions must be accounted for by incorporating interruption characteristics into the system wide average interruption cost coefficient (64). The program was used to study the generation expansion plans for a number of major USA utility service areas. The studies found that a major factor affecting the sensitivity of the optimum reserve to the interruption cost estimates was the relative need for the utilities to replace obsolete equipment.

Presently there appear to be at least three major approaches available which utilities can utilize when investigating generation expansion plans and performing cost/benefit studies of reliability. They are: Sanghvi's LOLP and linear programming optimization program, the Decision Focus Over/Under simulation program, and Poore's Frequency and Duration and EOP approach. A fourth approach which could be used but does not appear to have been used for that purpose (57) is the Optimal Generation Planning Program by General Electric (65). This approach is not discussed here because it does not inherently include the calculation of interruption costs.

Sanghvis' approach attempts to perform an overall general optimization of the generation system expansion and considers many factors such as capital, operating, and interruption costs and uncertainty of resource availability. While the program has the distinct advantage of being computationally efficient, it is of limited dependability because of its use of $/KWHR interruption cost coefficients and use of LOLP as a reliability measure. His approach does not explicitly consider the effects of EOP while the other two approaches do.

The Decision Focus Over/Under approach uses a somewhat more absolute prediction of reliability (based on simulations) and also considers the effects of uncertainties. It does not perform an optimization with respect to resource mix and does not adequately incorporate the effects of interruption characteristics such as frequency and duration.

Poore's approach uses as it's basis a more appropriate and more absolute predictor of reliability (F & D) than the other two approaches and incorporates fairly adequately the factors which effect interruption cost (such as interruption duration or on peak/off peak times). This approach is not presently available as part of a convenient package which can be used by utilities to perform an optimization study which calculates capital and operating costs in addition to interruption costs. Neither does it consider uncertainties such as of resource availability. This approach can readily utilize a utility's present F & D reliabilty assessment package and provide good estimators of interruption costs as a function of reserve margin.

3.3 Composite System Reliability Worth

Calculating interruption cost by combining composite system indices with interruption cost data suffers from much the same problems as in the generation case except that the reliability estimates can be more absolute because the transmission limitations are also included. Interruption cost estimates at composite system individual load points are more reasonable. The indices are more closely related to the actual physical phenomena experienced by the users. By focussing on individual load points instead of the entire system, the composition of customers which are shed during an interruption is more well defined. Usually composite system load points are comprised of many feeder lines, each with its own set of customers. Thus some uncertainty still exists as to what types of customers would be interrupted during load shedding.

Either global $/KWHR or user-duration specific cost factors can be combined with the indices. Use of the global factors ignores much of the physical situation such as interruption duration and customer mix, while applying user-duration specific data requires information that may not be available (e.g. load shedding customer mix). Any attempt to estimate costs however, still results in relative measures because the composite adequacy indices are relative indicators not absolute measures of adequacy. Composite system security must be considered in conjunction with adequacy to predict the actual reliability of a system. Presently however, composite system adequacy assessment is an immature technology while security assessment is even less developed.

No publications or references could be found which indicate that there has been a significant study of the cost/benefit aspects of reliability at the composite system level. Shipley's paper (6) which was discussed in Section 3.2, did deal with the reliability of the combined generation, transmission, and distribution systems but did not make use of predicted composite reliability measures. Ontario Hydro's SEPR study (10) did incorporate transmission reliability as well as generation reliability in the interruption costing, but did not consider the effects of varying transmission reliability as well as generation reliability.

It has been suggested that Poore's approach (22) to estimate interruption cost using F & D reliability indices could be applied to the composite system. A major problem is that this approach requires margin state probabilities to determine EOP occurrences. Composite reliability techniques based on simulation of the contingency states, load flows, and alleviation of line overloads by load shedding do not readily yield the required margin state probabilities.

In order to gain some practical insight into the estimation of interruption costs at the composite system level, it was decided that it would be useful to utilize in an example costing application the composite reliability program "COMREL" which was developed at the University of Saskatchewan (52). Because the reliability program is discussed briefly in Section 3.1, and in detail elsewhere, only the interruption costing aspects will be discussed here.

Similar to the generation reliability case, there are three basic aspects in the determination of composite reliability worth. The first, the set of reliability indices, was obtained for the 30 bus, 56 line model of the SPC system which was utilized in Medicherla's development work (52). Because the reliability program calculates indices for only one load level, eight runs were made: one each for 100%, 95%, 90%, 80%, 70%, 60%, 50%, and 40% of the peak load. The total cost to run the program on an IBM 360 and to obtain full printouts for the first and second order independent outages was approximately $1,000. The resulting interruption frequency, duration, and MW load curtailment average values for each load bus and each load level were inputted into a costing program. Probabilities for each load level were calculated from the SPC hourly load duration curve and input (.0008, .004, 0374, .1084, .2055, .3140, .1973, and .1326 respectively with the first value being for the peak value). For each load level, load bus, and user type the interruption cost was calculated for the expected MW load curtailed and interruption duration and then multiplied by the expected yearly interruption frequency. The expected interruption frequency, duration, load curtailment, energy not supplied, and interruption cost were aggregated using the load level probabilities to form yearly averages.

The second basic aspect is interruption cost data. Because data specific to Saskatchewan was not then available, Ontario Hydro and Swedish $/KW data was used for the small industrial, commercial, institutional, residential, and eight large user sectors.

The third basic aspect is the methodology for combining the first two aspects: reliability indices and cost coefficients. The first and probably most difficult step is to form a model of the load types at each bus. Discussions with SPC indicated that SPC and a number of other utilities do not collect and collate sufficient data to determine adequately the load composition at each bus. A further difficulty is that some utilities including SPC do not categorize customers by the Standard Industrial Classification system (SIC) but by less specific, utility unique definitions. This proved awkward because most interruption cost studies and other data bases utilize the SIC scheme. What was available was the load data and bus locations for twenty-six large users and the estimated system peak loads for each general customer category. This data was supplemented by information such as Statistics Canada data on regional distributions of census populations, retail establishment payrolls, value added of manufacturing production, and total energy use.

The yearly peak load for each user type at each load bus was estimated using the above information and much judgement. The two largest areas of uncertainty were the estimated division of load between the residential and farm sectors at individual buses and the amount of commercial load in the larger centres.

To assess interruption costs for an entire year, the variation of loads with time of year is required. Except for the large users, virtually no data for the Saskatchewan loads was available. Although there was some information for several user types in Ontario and Alberta, it was decided to assume that all the user loads varied in proportion to the total system load.

To assess interruption costs when only part of the load at a bus is shed, it is necessary to know which feeders are to be shed and the load types on these feeders. While the underfrequency load shedding schedule was available, the feeder user breakdown was not. The selection of load type shed can drastically affect the resulting costs and could possibly be used to minimize the interruption cost. Due to the lack of data, it was assumed that a proportionate part of each user load type on each bus would be shed. The resulting model of user load makeup and load shedding was crude but sufficiently realistic for an example study.

Table 3.4 contains the input values of the interruption frequencies. Similar tables for the interruption durations (which ranged from 5.68 hours to 13.05 hours) and bus load curtailment (8 MW to 126 MW) are not presented. Table 3.5 contains the energy-not-supplied for each load level and bus calculated from the input frequencies, durations, and MW curtailments. While the values generally vary as one would expect, a few anomalies exist (eg. a larger energy-not-supplied value for the 50% load level than the 60% load level). This is due to approximation errors which occur when the AC load flow results in divergent solutions.

Table 3.6 presents the interruption costs calculated for each user type and load bus. One obvious and yet interesting result is that due to variation in cost coefficients with user type, certain user types incurred disporportionate amounts of the total interruption cost, eg. The steel sector costs comprise 11.3% of the total costs but the steel sector portion of the total expected energy-not-supplied is only 1.53%.

The interruption cost results obtained in this study are not representative of the actual costs to the SPC system because of the inadequacy of the reliability model, interruption cost data, bus load data, load variation data, assumed load shedding model, use of average index values as opposed to the distribution of values, and other factors.

More advanced composite reliability techniques are required before realistic cost estimates can be obtained.

Table 3.4 Load Point Interruption Frequency for Each Load Level

Load Level (% of Peak Load)

BUS	100%	95%	90%	80%	70%	60%	50%	40%	AVERAGE
3	2.0840	1.6570	1.4190	0.6260	0.3230	0.0390	0.2100	0.0210	0.2521
10	2.5200	2.1200	2.0100	0.2800	0.0300	0.0000	0.0000	0.0000	0.1222
11	0.2400	0.2000	0.2000	0.2100	0.1700	0.0200	0.0100	0.0100	0.0758
12	0.5500	0.6500	0.3300	0.1300	0.0800	0.0800	1.7100	0.0300	0.4124
13	0.2100	0.4200	0.1700	0.1000	0.0800	0.0700	1.7100	0.0300	0.3988
14	13.6800	11.5600	8.4600	0.5800	0.1900	0.1600	0.1700	0.1700	0.5818
15	1.0000	0.8600	0.7400	0.2200	0.2000	0.1500	0.0000	0.0000	0.1440
16	4.0300	3.9900	3.9700	4.3800	0.0300	0.0100	0.0000	0.0100	0.6531
17	0.0000	0.0000	0.0000	0.0300	0.0100	0.0200	0.0000	0.0000	0.0116
18	0.4500	0.1300	0.1100	0.0400	0.0100	0.0100	0.0000	0.0000	0.0145
19	0.4000	0.2600	0.2400	0.1600	0.1300	0.0100	0.0000	0.0000	0.0575
22	0.3900	0.3100	0.2200	0.1600	0.1300	0.0000	0.0000	0.0000	0.0538
24	0.0000	0.0000	0.0000	0.0200	0.0000	0.0000	0.0000	0.0000	0.0022
25	0.0100	0.0100	0.0100	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004
26	3.1900	0.6400	0.4700	0.1700	0.1200	0.0300	0.0200	0.0100	0.0805
27	3.9700	3.9600	3.9300	0.0700	0.0300	0.0100	0.0100	0.0100	0.1862
28	6.8300	4.6600	4.5900	4.5800	4.4800	0.0800	0.0100	0.0900	1.6519
29	0.0200	0.0200	0.0200	0.0900	0.0500	0.0100	0.0100	0.0400	0.0313
30	0.0500	0.0400	0.0700	0.0500	0.0600	0.0400	0.1100	0.0400	0.0601
TOTAL	2.0840	1.6570	1.4190	0.6260	0.3230	0.0390	0.2100	0.0210	0.2521

Table 3.5 Annual Energy Not Supplied in MWHR

Load Level (% of Peak Load)

BUS	100%	95%	90%	80%	70%	60%	50%	40%	AVERAGE
3	1011.3	757.5	456.7	211.7	104.1	20.1	58.0	4.7	83.6
10	911.8	668.5	455.3	42.1	5.6	0.0	0.0	0.0	26.2
11	139.0	130.1	124.3	112.7	32.0	5.2	3.1	2.6	26.6
12	279.6	258.4	144.3	54.7	31.0	21.1	437.4	6.2	112.7
13	95.5	152.5	71.0	44.0	23.0	21.1	441.1	6.4	107.3
14	9656.7	6617.5	2732.8	535.7	269.3	206.6	134.3	30.5	345.2
15	643.1	571.2	496.5	175.5	77.8	28.2	0.0	0.0	65.2
16	1801.2	1705.0	1612.8	737.2	8.6	1.0	0.0	1.9	150.8
17	0.0	0.0	0.0	11.3	3.2	4.7	0.0	0.0	3.4
18	82.0	32.8	33.3	25.5	4.4	4.1	0.0	0.0	6.4
19	29.7	20.5	18.3	12.7	9.3	0.6	0.0	0.0	4.3
22	105.8	80.7	67.2	52.2	15.9	0.0	0.0	0.0	11.8
24	0.0	0.0	0.0	2.6	0.0	0.0	0.0	0.0	0.3
25	1.3	1.2	1.2	0.0	0.0	0.0	0.0	0.0	0.0
26	1051.6	743.4	182.9	111.1	86.6	31.6	16.8	8.7	54.9
27	914.2	541.5	181.7	14.8	11.4	2.3	2.3	2.3	15.1
28	2490.3	2208.4	2078.4	1856.7	1261.0	19.7	2.4	19.6	558.2
29	4.7	4.2	3.3	6.8	7.4	1.6	1.5	3.1	3.6
30	4.7	3.0	17.0	19.9	21.0	10.2	21.4	7.5	15.6
TOTAL	19222.2	14496.5	8677.0	4027.4	1971.7	377.9	1118.2	93.5	0.0

The total energy not supplied is 1591.34 MWHR

Table 3.6 Load Point Interruption Cost in Thousands of Dollars for Each User Type

User Types

BUS	IPL	POT	OIL	STEEL	CHEM	REF	PAPER	INS	OILFLD	INDUS	COMMERC	RES	FARM	TOTAL
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.31	14.94	18.68	11.43	21.29	85.66
10	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.24	10.51	6.93	6.14	29.88
11	0.00	3.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.80	2.73	14.95	28.45
12	0.00	0.00	0.00	0.00	10.44	0.00	0.00	11.31	0.00	39.52	22.28	11.68	6.71	101.95
13	0.00	58.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.78	4.30	1.30	13.29	86.42
14	0.24	0.00	0.00	210.55	1.53	5.09	0.00	0.00	0.00	47.19	97.07	47.25	1.70	410.62
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.08	26.04	23.92	11.87	71.91
16	0.73	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.31	24.44	17.43	67.82	144.73
17	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.08	0.00	0.81	1.67	0.47	1.00	4.05
18	0.00	3.76	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.06	0.48	4.39
19	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.37	0.00	2.38	2.78
22	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.22	3.03	1.49	6.69	13.46
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.12	0.01	0.24	0.40
25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.04	0.06
26	0.00	7.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.33	25.24	10.35	2.29	62.18
27	0.03	0.00	1.16	0.00	0.21	0.00	0.00	0.00	1.14	0.71	6.73	1.64	1.42	13.04
28	0.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	245.74	358.55	42.72	128.88	776.60
29	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.24	0.13	0.76	0.68	0.87	2.70
30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.31	4.23	8.24	2.72	2.52	19.02
TOTAL	1.82	74.44	1.16	210.55	12.19	5.09	0.03	11.40	22.00	431.28	614.96	182.80	290.58	0.00

The total annual interruption cost is $1,858,270.00

4 DISTRIBUTION SYSTEM RELIABILITY WORTH

Evaluation of reliability worth results in more realistic and meaningful estimates for distribution systems than for generation or composite systems. This is because the distribution system is the part of the power system which is the "closest" to the users and because distribution reliability indices provide a fairly absolute measure of reliability.

The evaluation of distribution system reliability is considered first, followed by the application of reliability worth.

4.1 Distribution System Reliability Indices

The distribution system is the part of the power system which connects individual users' services to the generation and bulk transmission systems. Subtransmission circuits, distribution substations, primary feeders, distribution transformers, secondary circuits, and user connections all form different parts of the distribution system (66). Because this section is only intended to provide an introduction to distribution system reliability and a framework for the remaining discussion, distribution systems will be simply dealt with as if they consisted only of feeders. Other publications provide a more general and detailed presentation on distribution reliability (eg. 66, 67). This presentation will still provide a suitable background for the discussion on interruption costing because the reliability principles and indices for the simple feeder system and the more complete distribution system with substations and transformers are similar.

Reliability assessment in distribution systems is concerned with system performance at the customer end, ie. at the load points. The basic indices normally used to predict the reliability of a distribution system are: Average Load Point Failure Rate, Average Load Point Outage Duration, and Average Annual Load Point Outage Time. The indices are calculated using component failure rates and repair times together with other system restoration times. These indices are used to predict future system performance. Utilities also calculate service performance indices to describe statistically the past performance of the system. The most common performance indices - System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI), Customer Average Interruption Frequency Index (CAIFI), Average Service Availability Index (ASAI) and others (3) - can also be calculated directly from the three basic predictive indices.

An example calculation of the reliability indices for a radial distribution system is presented for five sets of operating assumptions: base case, base case with back-feed, back-feed with conditional load transfer capability, base case with solidly connected laterals, and base case with non-perfect lateral fault clearing. The more common system performance indices are also calculated. These calculations are included to show that the performance statistics collected by CEA (such as SAIFI, SAIDI and CAIDI) can be easily related to the standard reliability evaluation indices. The following chapter presents and compares the results of Monte Carlo simulation studies for the same system, which is shown in Figure 4.1.

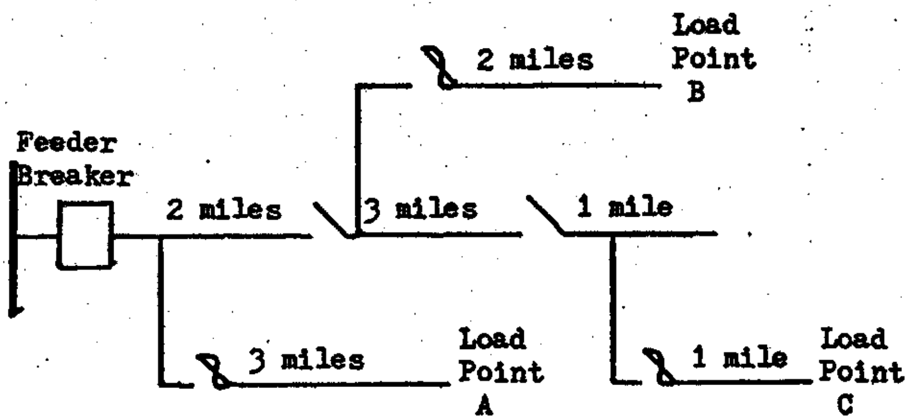


Figure 4.1 Manually Sectionalized Primary Main

In this base case configuration, all switches are normally closed and the customer load points A, B, C are supplied from the primary main by fused laterals. The feeder breaker and the substation supply bus are assumed to be fully reliable. The individual component data obtained from the history of similar components under similar conditions are as follows.

Primary main	0.10 failure/circuit mile/year
	3.0 hrs. average repair time
Primary lateral	0.25 failures/circuit mile/year
	1.0 hrs. average repair time

Manual sectionalizing time for any switching action = 0.5 hrs.

The simplest approach is to perform a failure modes and effect analysis in a table form and utilize the basic equations:

$$\lambda_s = \Sigma\lambda_i \quad \text{failures/yr.} \tag{4.1}$$

$$r_s = \frac{\Sigma\lambda_i \, r_i}{\Sigma\lambda_i} \text{ hours/failure} \tag{4.2}$$

$$U_s = \lambda_s \, . \, r_s \text{ hours/year} \tag{4.3}$$

This procedure is shown in Table 4.1.

Table 4.1 Case 1 (Base Case) Calculations

Component	Load Point A			Load Point B			Load Point C		
	λ	r	λ r	λ	r	λ r	λ	r	λ r
	f/yr	hrs	hrs/yr	f/yr	hrs	hrs/yr	f/yr	hrs	hrs/yr
Primary Main									
2 m section	0.2	3.0	0.6	0.2	3.0	0.6	0.2	3.0	0.6
3 m section	0.3	0.5	0.15	0.3	3.0	0.9	0.3	3.0	0.9
1 m section	0.1	0.5	0.05	0.1	0.5	0.05	0.1	3.0	0.3
Primary Lateral									
3m section	0.75	1.0	0.75	--	--		--		
2m section	--			0.5	1.0	0.5	--		
1m section	--			--			0.25	1.0	0.25
	1.35	1.15	1.55	1.1	1.86	2.05	0.85	2.41	2.05

Summarizing the results.

Table 4.2 Case 1 Indices

	A	B	C
λ - failures/year	1.35	1.1	0.85
r - hours/failure	1.15	1.86	2.41
U - hours/year	1.55	2.05	2.05

It can be seen that load point C, despite being at the extremity of the primary main, has the lowest failure rate due to its relatively short primary lateral. It has the longest average restoration time, however, due to the fact that all restoration is by repair rather than by isolation of the faulted section and restoration by switching action. In the case of load point A, any failures on the primary main other than on the initial 2 mile section involve restoration by switching rather than by repair. There are many configurations particularly in rural locations which have a topology similar to that shown in Figure 4.1. The results shown in Table 4.2 can be used to obtain the standard performance indices. Assume that there are 250, 100 and 50 customers respectively at load points A, B and C, giving a total of 400 customers in the system.

Annual Customer Interruptions =

$$(250)(1.35) + (100)(1.1) + (50)(0.85) = 490$$

System Average Interruption Frequency Index = SAIFI

$$= \frac{\text{total number of customer interruptions}}{\text{total number of customers served}} \qquad (4\text{-}4)$$

$$\text{SAIFI} = \frac{490}{400} = \underline{1.23}$$

Customer Interruption Duration =

$$(250)(1.55) + (100)(2.05) + (50)(2.05) = 695$$

System Average Interruption Duration Index = SAIDI

$$= \frac{\text{sum of customer interruption durations}}{\text{total number of customers served}} \qquad (4\text{-}5)$$

$$\text{SAIDI} = \frac{695}{400} = \underline{1.74}$$

Customer Average Interruption Duration Index = CAIDI

$$= \frac{\text{sum of customer interruption durations}}{\text{total number of customer interruptions}} \qquad (4\text{-}6)$$

$$\text{CAIDI} = \frac{695}{490} = \underline{1.42}$$

Average Service Availability Index = ASAI

$$= \frac{\text{customer hours of available service}}{\text{customer hours demanded}} \qquad (4\text{-}7)$$

$$\text{ASAI} = \frac{(400)(8760) - 695}{(400)(8760)} = \underline{0.999802}$$

These calculated values can be compared with measured values or, if available, with standard indices for the system to determine if the configuration shown in Figure 4.1 meets the system requirement.

It may also be possible to restore service to this system by back feeding from another adjacent circuit. This configuration is shown in Figure 4.2.

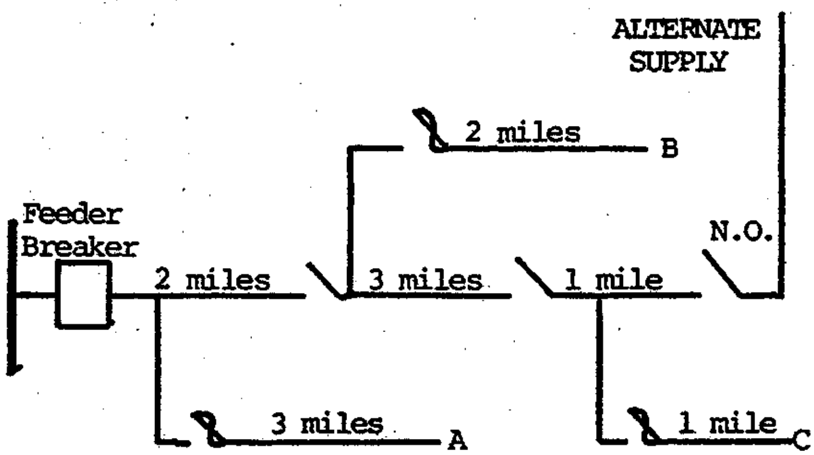


Figure 4.2 Manually Sectionalized Primary Main with Alternate Supply

Table 4.3 shows the effect of this alternate supply on the calculated reliability indices using an average switching time of 1 hour for the alternate supply.

Table 4.3 Case 2 Calculations

Component	Load Point A			Load Point B			Load Point C		
	λ	r	λr	λ	r	λr	λ	r	λr
	f/yr	hrs	hrs/yr	f/yr	hrs	hrs/yr	f/yr	hrs	hrs/yr
Primary Main									
2 m section	0.2	3.0	0.6	0.2	1.0	0.2	0.2	1.0	0.2
3 m section	0.3	0.5	0.15	0.3	3.0	0.9	0.3	1.0	0.3
1 m section	0.1	0.5	0.05	0.1	0.5	0.05	0.1	3.0	0.3
Primary Lateral									
3m section	0.75	1.0	0.75	--			--		
2m section				0.5	1.0	0.5	--		
1m section				--			0.25	1.0	0.25
	1.35	1.15	1.55	1.1	1.5	1.65	0.85	1.24	1.05

Summarizing the results.

Table 4.4 Case 2 Indices

	A	B	C
λ - failures/year	1.35	1.1	0.85
r - hours/failure	1.15	1.5	1.24
U - hours/year	1.55	1.65	1.05

Overall configuration indices

SAIFI = 1.23
SAIDI = 1.51
CAIDI = 1.23
ASAI = 0.999827

It can be seen that the load point failure rates are not affected by the ability to backfeed from an alternate configuration. This will apply in all cases in which the restoration of service is done manually. If automatic switching is used and the customer outage time is considered to be so short that the event is not classed as a failure then the overall failure rate will be reduced to a value closely related to the primary lateral value. This assumes that the automatic sectionalizing and service restoration has a high probability of successful operation. The ability to backfeed has a pronounced effect on the length of the interruption particularly for those customers at the extremities of the primary main. This effect could be reduced considerably if the ability to backfeed is conditionally dependent upon the loading condition in the alternate supply. The restoration times in Table 4.3 for load points B and C can be modified to reflect the probability of being able to supply these loads from the alternate supply. This is shown in Table 4.5 using a transfer probability of 0.5.

Table 4.5 Case 3 Calculations

Component	Load Point A			Load Point B			Load Point C		
	λ	r	λr	λ	r	λr	λ	r	λr
	f/yr	hrs	hrs/yr	f/yr	hrs	hrs/yr	f/yr	hrs	hrs/yr
Primary Main									
2 m section	0.2	3.0	0.6	0.2	2.0	0.4	0.2	2.0	0.4
3 m section	0.3	0.5	0.15	0.3	3.0	0.9	0.3	2.0	0.6
1 m section	0.1	0.5	0.05	0.1	0.5	0.05	0.1	3.0	0.3
Primary Lateral									
3m section	0.75	1.0	0.75	--			--		
2m section	--			0.5	1.0	0.5	--		
1m section	--			--			0.25	1.0	0.25
	1.35	1.15	1.55	1.1	1.68	1.85	0.85	1.82	1.55

Summarizing the results.

Table 4.6 Case 3 Indices

			A	B	C
λ	-	failures/year	1.35	1.1	0.85
r	-	hours/failure	1.15	1.68	1.82
U	-	hours/year	1.55	1.85	1.55

Overall configuration indices

SAIFI = 1.23
SAIDI = 1.63
CAIDI = 1.33
ASAI = 0.999814

The average outage time at load points B and C is now somewhere between the values given in Tables 4.2 and 4.4. In Table 4.2, the system loads are non-transferable, in Table 4.4 they are transferable, while Table 4.6 depicts a conditionally transferable situation. The transfer capability tends to diminish with time as the load increases, if circuit modifications are not made to redistribute the customer requirements.

It can be seen from the cases studied that the load point failure rates are dependent upon the components exposed to failure and the degree of automatic isolation of a failed component in the network. This effect can be easily seen in the network of Figure 4.1. If each lateral is solidly connected to the primary main, all load points will have the same failure rate, as any fault will result in the feeder breaker tripping. The analysis in this case is shown in Table 4.7.

Table 4.7 Case 4 Calculations

Component	Load Point A			Load Point B			Load Point C		
	λ	r	λr	λ	r	λr	λ	r	λr
	f/yr	hrs	hrs/yr	f/yr	hrs	hrs/yr	f/yr	hrs	hrs/yr
Primary Main									
2 m section	0.2	3.0	0.6	0.2	3.0	0.6	0.2	3.0	0.6
3 m section	0.3	0.5	0.15	0.3	3.0	0.9	0.3	3.0	0.9
1 m section	0.1	0.5	0.05	0.1	0.5	0.05	0.1	3.0	0.3
Primary Lateral									
3m section	0.75	1.0	0.75	0.75	1.0	0.75	0.75	1.0	0.75
2m section	0.5	0.5	0.25	0.5	1.0	0.5	0.5	1.0	0.5
1m section	0.25	0.5	0.125	0.25	0.5	0.125	0.25	1.0	0.25
	2.10	0.92	1.93	2.10	1.39	2.93	2.10	1.57	3.30

Summarizing the results.

Table 4.8 Case 4 Indices

		A	B	C
λ	- failures/year	2.10	2.10	2.10
r	- hours/failure	0.92	1.39	1.57
U	- hours/year	1.93	2.93	3.30

Overall configuration indices

SAIFI = 2.10
SAIDI = 2.35
CAIDI = 1.12
ASAI = 0.999732

The results shown in Table 4.8 illustrate the effect on the load point failure rates of increasing the exposure to failure of the overall configuration. The results shown in Table 4.2 illustrate the effect of perfect isolation arising from a failure on a primary lateral. The probability associated with successful isolation of a primary lateral fault will depend upon the design of the protection co-ordination scheme and on the operation and maintenance of the scheme. Table 4.9 shows the calculations for the case in which the probability of successful isolation of a primary lateral fault is 0.9.

Table 4.9 Case 5 Calculations

Component	Load Point A			Load Point B			Load Point C		
	λ	r	λr	λ	r	λr	λ	r	λr
	f/yr	hrs	hrs/yr	f/yr	hrs	hrs/yr	f/yr	hrs	hrs/yr
Primary Main									
2 m section	0.2	3.0	0.6	0.2	3.0	0.6	0.2	3.0	0.6
3 m section	0.3	0.5	0.15	0.3	3.0	0.9	0.3	3.0	0.9
1 m section	0.1	0.5	0.05	0.1	0.5	0.05	0.1	3.0	0.3
Primary Lateral									
3m section	0.75	1.0	0.75	0.075	0.5	0.0375	0.075	0.5	0.0375
2m section	0.05	0.5	0.025	0.5	1.0	0.5	0.05	0.5	0.025
1m section	0.025	0.5	0.0125	0.025	0.5	0.0125	0.25	1.0	0.25
	1.425	1.114	1.5875	1.20	1.75	2.10	0.975	2.17	2.1125

Summarizing the results.

Table 4.10 Case 5 Indices

	A	B	C
λ - failures/year	1.425	1.20	0.975
r - hours/failure	1.114	1.75	2.17
U - hours/year	1.5875	2.10	2.1125

Overall configuration indices

SAIFI = 1.31
SAIDI = 1.78
CAIDI = 1.36
ASAI = 0.999797

The results for each of the five cases considered are shown in Table 4.11.

Table 4.11 Summary

	CASE 1	2	3	4	5
Load Point A					
λ f/yr	1.35	1.35	1.35	2.10	1.425
r hrs	1.15	1.15	1.15	0.92	1.114
U hrs/yr	1.55	1.55	1.55	1.93	1.5875
Load Point B					
λ f/yr	1.10	1.1	1.1	2.10	1.20
r hrs	1.86	1.5	1.68	1.39	1.75
U hrs/yr	2.05	1.65	1.85	2.93	2.10
Load Point C					
λ f/yr	0.85	0.85	0.85	2.10	0.975
r hrs	2.41	1.24	1.82	1.57	2.17
U hrs/yr	2.05	1.05	1.55	3.30	2.1125
System Indices					
SAIFI	1.23	1.23	1.23	2.10	1.31
SAIDI	1.74	1.51	1.63	2.35	1.78
CAIDI	1.42	1.23	1.33	1.12	1.36
ASAI	0.999802	0.999827	0.999814	0.999732	0.999797

Case	Condition
1	Base case shown in Figure 4.1
2	System shown in Figure 4.2 alternate supply average switching time of 1 hr.
3	As in Case 2, conditional load transfer probability of 0.5.
4	As in Case 1, solidly connected laterals.
5	As in Case 1, probability of successful lateral fault clearing = 0.9.

4.2 Application of Reliability Worth

Assessment of the worth of reliability is most feasible when considering the distribution system. This is particularily true of the predictive reliability indices. This is less true of the historical performance indices because of their aggregated and global nature which tends to make them similar to composite system reliability indices when considering reliability worth. However, if sufficient information concerning the number and types of users interrupted and the times of interruption occurences is collected, the performance indices can be used with interruption cost data to provide the most absolute measure of reliability worth of any of the indices. Because of the cost of collecting and collating such detailed data it is unlikely such measures will be obtained. Henceforth, when discussing distribution system reliability worth, this thesis will be referring to worth measures obtained from predictive indices.

A theoretical basis for calculating the user interruption cost measure from the load point indices is extremely simple and straightforward. The average yearly system interruption cost C can be given by the following equation:

$$C = \ _{i,j} \ c_i(r_j)\, d_{ij} \quad _j \qquad (4\text{-}8)$$

where:

$c_i(r_j)$ = interruption cost in \$/kW for duration r_j and user type "i"

r_j = interruption duration in hours for load point "j"

d_{ij} = demand in kW for user type "i" and load point "j"

$_j$ = number of failures per year

Assumptions contained in this formulation and difficulties in applying the formula are discussed in Section 4.3. This formula and variations of it have been used in many publications concerning the derivation and application of distribution system reliability worth. A CEA report contains a bibliography listing such papers (18, 20). Some publications use a form which contains no explicit representation of duration but instead contain both kW and kWHR interrupted terms (eg. 68, 13). This form, which is based on the type of data collected from the IEEE surveys (16, 17), is somewhat dependent on duration due to the kWHR term but does not reflect costs which vary nonlinearly with duration. Other forms use a cost term related to duration squared (69) or to only kWHR not supplied (eg. 70). Such types of forms yield a less faithful measure of interruption cost than that of Eq. 4.8 which is explicitly dependent on duration (see Section 5.6). Because of its greatest applicability the basic form of Eq. 4.8 is used in many studies (eg. 72, 71, 10) and is the one used in this thesis.

Assessment of the worth of reliability is more feasible for the distribution system than for generation and composite systems because of the following factors:

1) The form of the load point indices is strongly relateable to the actual user experience. The duration and occurrence frequency physically describe the interruption as seen by the user at the load point, unlike concepts such as LOLP or LOLE.
2) Security and operating considerations are much less important. The indices provide an almost absolute measurement of customer end reliability as opposed to a relative indicator which is what

the generation and composite indices provide. The cost estimates can thus become closer to being an absolute measure as well (5).

3) Indirect effects are less likely to occur and macroeconomic techniques probably are not needed because of the nature of distribution interruptions which are localized, random, and small scale as opposed to generation type interruptions which are of a larger scale (48).

4) At distribution load points, the user types are not as aggregated as at composite system load points or as for the entire power system. Thus the makeup of customers interrupted during distribution failures is well defined although the information is not presently collected. Obtaining estimates for the breakdown of load and customer type is therefore feasible for each load point.

5) User duration specific data can be readily applied. Global interruption cost data need not be used. Indeed global data is unsuitable because of the great variation in customer mix from load point to load point.

6) Because of the specificity of the measures, the supply adequacy and interruption cost for individual important or sensitive users can be estimated. Local system or user facility improvements could be decided upon and rate-reliability contractual obligations undertaken on the basis of this information.

7) Because of the smaller scale of the system, it is computationally easier to perform the analyses and include various factors.

4.3 Considerations and Problems in Applying Reliability Worth to Distribution Systems

This section discusses specific considerations and problems encountered when applying reliability worth. The discussion is specific to distribution systems but is also pertinent for generation and composite systems. The main factors can be categorized as being related to formula assumptions and variations, the reliability indices, the interruption cost data, and the process of applying the worth data.

4.3.1 Formula Assumptions and Variations

1) In Eq. 4-8 all the terms are average values although each characteristic in actuality consists of a range of values. This formulation is consistent with conventional reliability analyses which are concerned only with the expected or average value of the particular measure of reliability. If a cost function is approximately linear in the region of interest, this approach can result in total or average interruption cost estimates which are reasonable although no distributional information concerning the reliability and costs is obtained. If the cost function is nonlinear however, a significant error may result. The following simple calculation exemplifies this.

Consider a load point with only 1 customer and with an interruption history for a year of 2 one hour and 1 four hour interruptions. As tabulated in Table 4.12, assume three different cost functions. When comparing the total interruption cost calculated using the average duration and the entire duration distribution, it can be seen that for the linear cost functions the computed costs agree but for the nonlinear cost function there is considerable error.

Table 4.12 Example Effect of Nonlinear Cost Function

	COST FUNCTION A $ / kW	B $ / kW	C $ / kW
1 Hr. Cost	1	1	1
2 Hr. Cost	1	2	2
4 Hr. Cost	1	4	20
Total Cost Using Average Duration	3	6	6
Total Cost Using Duration Distribution	3	6	22

Probability distributions associated with distribution system indices and interruption costing are considered in detail in the next chapter. It is shown that in certain situations the error involved in using average indices is indeed considerable but that in many situations only a moderate amount of error results from ignoring the distributional variation of the interruption duration.

2) The form of Equation 4.8 implicitly assumes that the cost per interruption is independent of the interruption frequency. The reasonability of this assumption is confirmed by studies which indicate that cost per interruption is frequency independent within the range of frequencies normally considered (18, 39). Should the interruption frequency be abnormally high (eg. more than once a month), the costing equation would need to be modified.

3) Virtually all the factors involved in the interruption cost scenarios vary with the time of occurrence. The cost of an interruption varies with the time but so does the electrical load. An assumption that is made is that interruption cost is related to the load and that using kW demand (or kWHR) as a divisor tends to normalize the costs. Often in calculations the user costs at system peak times are divided by their individual yearly peak demands. These costs are then input into analyses with no modification for time of interruption. Usually the customer demands are assumed to be the system capacity or the peak demands. The resulting cost estimates are qualified as being relative measures or overstated (eg. 71, 10, 73).

Khatib attempts to at least partially resolve this problem by assigning a scaling factor to the interruption costs which is proportional to the system demand as it varies with time of day (62). Non-essential loads are excluded as having negligible effect on consumer welfare. This approach however is not substantiated by any evidence or data and is rather arbitrary.

While most cost studies provide little data on cost variation with time, the CEA surveys provide a quantitative measure of the variation of interruption cost as a function of time of day, day of week and month of the year (18). However, the measures are not strictly independent of each other and cannot simply be superimposed. As well the variation was not correlated with variation of demand. An alternative approach is to develop cost coefficients for on peak/off peak and seasonal scenarios as was done in a DOE study (74). Quantitative measures such as these could be used to derive scaling factors or functions to be used in conjunction with Eq. 4.8. Additional information that would be required to do this is the variation of interruption frequency (and possibly duration) with time of occurrence.

If sufficient data were available all three considerations could, with only some difficulty, be incorporated into the costing process associated with Eq. 4.8. A simpler and more realistic approach would be to include them in a simulation process instead of a strictly analytical one. However the computational effort and cost could be considerable for either approach, especially the simulation approach.

4.3.2 Considerations Related to Reliability Indices

1) Although distribution indices are a more absolute measure than generation or composite system indices, they are still not perfect measures. One important deficiency with the distribution indices is that they do not adequately reflect the effects of possible catastrophic events which cause interruptions of very long durations. The interruption costs due to such events could be quite high and would not be included in the cost estimate. The reliability indices and cost estimates are not absolute measures but can provide a realistic and fairly faithful indication for distribution systems.

2) The definition of what constitutes an interruption which underlies reliability analyses does not normally include either very short interruptions such as caused by OCR operations or distorted wave-

forms such as overvoltage spikes caused by switching or lightning. While these factors should be taken into account when considering the quality of a supply, it is not feasible to include them presently in analyses because of a lack of data and methodology.

4.3.3 Considerations Related to Interruption Cost Data

The points made in this section are mainly drawn from the discussion of cost data in Chapter 2 and a CEA report (18) and in some cases are enlarged or elaborated upon. Generally there are presently three overall problems:

i) The methodology and definitions concerning the effects and costs of interruptions is in need of further development.

ii) The methodology concerning the collection and determination of cost data must be improved in conjunction with the above.

iii) There is presently a lack of comprehensive, accurate and adequate data.

Some of the more specific problems with the data are:

1) Most of the data is based upon predictions of effects and costs rather than actual effects and costs. This is an inevitable result of the situation in North America and Western Europe where the reliability levels tend to be high and user experience with interruptions minimal.

2) There is little data available for frequent or long duration interruptions. Often, available data must be extrapolated from.

3) Interruption costs are probably dependent on reliability level. Use of present data is limited to scenarios with reliability levels

similar to the present level.

4) Interruption cost varies greatly with not only the type of user but also with users in the same category. Before making use of the reported mean values, the effects of these variations must be considered. Utilities are recommended to survey their own customers to obtain data, especially for the larger or more sensitive users.

5) There is a further great variation of interruption cost by time of interruption occurrence, weather, economic activity, interruption characteristics such as advance warning, and other factors. Data cannot be collected for every possible scenario.

6) Presently available data usually assumes some form of dependence on peak demand and/or energy consumption. Data is normalized by dividing by kW or kWHR. Unfortunately there does not appear to be a large correlation between cost and user peak kW (or kWHR) (18). Because of the present lack of another more reasonable normalizing factor, such an approach must be utilized.

7) Future interruption costs may be affected by changes in factors such as the degree of conservation, types of industrial processes, use of standby and uninterruptible power supplies, and dependency on computer systems.

8) All of these above factors are aggravated by the fact that reliability studies often involve time periods of the next 5, 10, 20, or even 30 years. As always in such studies, the uncertainty becomes immense.

4.3.4 Considerations Related to the Application

1) When determining system or load point interrupt task is the determination of the user load in user category and the subsequent aggregation of user category costs to form an overall estimate of cost. To perform this task adequately there is often insufficient data concerning both the load categorized by user type on specific feeders or buses and variation of that load. Some form of global user category data is usually available and some assumptions must be made concerning the distribution of the loads amongst the buses or feeders. Load variation data is only available usually on a global basis (if at all) and assumptions must be made for more local variations. A common but not very realistic practice is to determine peak demands (often based on utility equipment capacity) and neglect load variation (eg. 71). As marketing load studies and SIC customer categorization become more prevalent, this lack of data may become less problematical. Although commercial computer packages to perform reliability planning studies incorporating interruption costs are becoming available, the derivation of sector interruption costs and aggregation of sector costs often may not be included in the package because of the variation in user categorization and data availability from utility to utility (eg. 63, 64).

2) In addition to the long term changes mentioned in Section 4.3.3, more fundamental changes related to load management, spot rates, real time electrical marketing, and flexible reliability/rate contracts can change the overall situation drastically. Studies such

as discussed here may evolve into more direct and possibly even real-time feedback from users which would be used as a basis for system planning and operating.

5 PROBABILITY DISTRIBUTIONS ASSOCIATED WITH DISTRIBUTION SYSTEM INDICES AND INTERRUPTION COSTING

Conventional reliability analyses are concerned with the expected or average value of the particular measure of reliability. Little consideration has been given in the past to the variation of that measure about its mean. For example, when the frequency of failures at a load point is predicted, only the average value of that quantity, the Load Point Failure Rate, is typically calculated. The probability that the load point will suffer a specified number of failures in a year is not normally calculated. Similarly, the expected values of the duration indices are determined but the probabilities of various durations are not calculated. The mean values are extremely useful and are the primary indices of load point adequacy. There is, however, an increased awareness of the need for information related to the variation of the reliability measures around their means (72, 75, 76, 77, 78, 79). This information can prove useful in studies involving:

1) the probability of the interruptions being longer than the Critical Service Loss Duration Time or some other time of interest (16, 17, 77). This information is especially useful in the design of distribution systems for industrial customers with critical processes or commercial customers with very non-linear costing functions.
2) the probability of a certain number of failures occurring in a particular year (75, 76, 80, 81, 82) (perhaps to determine annoyance factor).

3) the comparison of performance indices of different years or different systems to determine the probability of their having a different average value. Such a comparison would assist planners to judge whether differences in indices indicate real changes in performance or are due to statistical variation. (eg. the SAIDI, SAIFI, and CAIDI of a system could be compared on a year-to-year basis for significant variation) (79).
4) the validation of reliability models and the applicability of reliability data (77, 80, 81, 82, 78). Outage data is often insufficient and inadequate. The index probability distributions can be useful in estimating the errors resulting from inaccurate data. Confidence intervals could be computed. This type of study is even more applicable in generation reliability studies.
5) the determination of customer costs of interruptions using non-linear cost functions.
6) the variation of customer interruption costs about their means.

Most reliability cost-benefit studies calculate the cost of interruptions by computing the cost due to an interruption of average duration rather than averaging the costs due to the entire set of interruption durations. In addition to depending on the cost curve shape and other factors, the average cost calculated for the set of interruption durations varies with the shape of the distribution which defines the duration probabilities. Since in reality, interruptions have a range of durations rather than just the average value, the cost calculated using the distribution is a more realistic one. A major objective of this thesis is to investigate these distributions and the error involved in using only the average interruption duration to calculate interruption cost.

5.1 Probabilistic Simulation of Distribution Reliability Indices

Probability distributions provide a practical vehicle to describe the variation of reliability measures about their means. The approach taken in this study to determine these distributions was to perform probabilistic (Monte Carlo) simulations of typical radial distribution systems. This section provides some explanation of this approach and the simulation program that was developed.

An alternative approach is to analyse actual interruption data for distributional information. While a number of such studies have been published (eg. 77, 80, 81, 82, 79), most are studies of outages of components such as lines rather than studies of load point interruptions. Load point index distributions are dependent not only on combinations of component outages but also on system configurations and restoration activities. With the increasing emphasis utilities are placing on data collection it is possible that in the near future more statistical data on load point interruptions will be available. Not only can simulation studies provide useful information before comprehensive historical data is available but they can provide information that would not otherwise be possible to obtain. For example, simulations can provide information concerning the effects of very specific system configurations. Furthermore, simulations can deal with predictive reliability indices not just performance indices. These advantages become obvious when one makes use of distributional studies of performance data such as one by Koval and Erbland (79). The paper provides quite useful information and an excellent presentation of the distributional tendencies. Such an approach however is not a good means to study the effects of specific characteristics such as manual sectionalizing capabilities. The reliability of specific designs for a line could not be analyzed by performance data studies but could be analyzed by predictive reliability indices and simulations.

In Monte Carlo simulation, an artificial history of the reliability of a system is generated by the use of random number generators and the probability distributions which are assumed to describe the system parameters. The essence of the process consists of:

1) a random number generator choosing a number between 0 and 1
2) the time to failure of a component is then given by this number and the cumulative probability distribution which is assumed to describe the failure process
3) a random number generator chooses another number between 0 and 1
4) the time to repair of the failed component is then given by the new number and the cumulative probability distribution assumed to describe the repair process
5) the system is now in its non-failed state and the cycle can be repeated

The simulation becomes more complicated by the presence of more than one element in the system, additional restoration processes such as sectionalizing, backfeeding, and fuse failure, and the use of different distributions in the same simulation. Because Monte Carlo simulation is a widely applied technique and described fully elsewhere (83, 84, 85), a more detailed description will not be provided here.

A program was developed at the University of Saskatchewan to simulate the performance of any N-section radial distribution system with loads connected to laterals or directly to the primary mains. Any combination of exponential, normal, log-normal, and gamma distributions can be used to simulate the failure, repair, manual sectionalizing, alternate supply and fuse times. Costs of each interruption can be calculated from 1 minute, 20 minute, 1 hour, 4 hour and 8 hour cost data. The program outputs for each load point: the mean, standard deviation, and distribution histogram of the annual interruption time, interruption duration, annual interruption frequency, and annual interruption cost. For the entire system, it provides similar outputs for SAIFI, SAIDI, CAIDI, cost per interruption, and annual interruption cost. Appendix A contains a more complete program description and a flow chart.

Studies were performed on the 6 section example system of Figure 4.2 and on a larger 18 section system. The studies included all of the five cases discussed in Section 4.1:

1) Base Case
2) Base Case with alternate supply available
3) Base Case with alternate supply conditional load transfer probability of .5
4) Base Case with solidly connected laterals
5) Base Case with probability of successful lateral fault clearing = 0.9.

The average values derived from the simulation of the example system for a period of 5000 years are compared in Tables 5.1 and 5.2 with the values from a 1000 year simulation and with the values derived from the analytical formulas. In these simulations, the failure times are assumed to be exponentially distributed and the repair times are assumed to be lognormally distributed. A simulation study length of 1000 years and even 500 years was found to give satisfactory results although 5000 year studies were used to provide slightly more accurate results.

Table 5.1 Load Point Index Values - Case 1

Load Points	A	B	C
Failures Year			
- analytical	1.35	1.1	.85
- 5000 year simulation	1.35	1.1	.86
- 1000 year simulation	1.40	1.1	.89
Hours/Failure			
- analytical	1.15	1.86	2.41
- 5000 year simulation	1.17	1.88	2.41
- 1000 year simulation	1.16	1.83	2.33
Hours/Year			
- analytical	1.55	2.05	2.05
- 5000 year simulation	1.57	2.07	2.07
- 1000 year simulation	1.63	2.02	2.07

Table 5.2 System Performance Index Values - Case 1

	SAIFI	SAIDI	CAIDI
- analytical	1.23	1.74	1.42
- 5000 year simulation	1.22	1.76	1.34
- 1000 year simulation	1.26	1.78	1.32

For every simulation performed in the series of studies, the simulation derived values and the analytical formula values were compared. Within an acceptable statistical error, the values for the load point indices, SAIFI, and SAIDI matched. The average values are unaffected by which distributions are assumed to underly the restoration times and hence the indices calculated by the standard reliability equations do not depend on the assumed distributions. When calculated as the average of the CAIDI indices for each year, CAIDI however, is dependent on the underlying distributions. The reason for this dependence is detailed in Appendix B. When CAIDI is calculated for the entire simulation period instead of for each year, the dependence disappears. Because CAIDI is in reality calculated on a yearly basis, all of the CAIDI values presented in this study will be the yearly averages despite the distributional dependence.

5.2 Distribution of Load Point Failure Rate

This series of studies indicate that the load point failure rate is reasonably described by the Poisson distribution with a Chi-squared level of significance = .1 (76, 86). This result is in agreement with theoretical considerations and a previous study by Patton (75). Only one parameter is required to describe the Poisson distribution, ie. the expected annual failure rate. Since this value is the index normally calculated, the distributional information can be obtained with minimal extra effort. Probability information concerning the failure rate can be easily determined from the Poisson distribution equation.

$$P(n) = P[\text{number of failures} = n \text{ in time } t] \qquad (5\text{-}1)$$
$$= \frac{(\lambda t)^n e^{-\lambda t}}{n!}$$

Figure 5.1 depicts the distributions associated with the failure rates of load points A, B and C for Case 1. The distributions are noticeably different for the three load points. At load point A, years with one failure occur most frequently while at load point C, years with no failures occur most frequently. Concurrent with an increase in the average failure rate, the shape of the distribution varies significantly and the individual failure rate probabilities increase in a non-linear fashion. This can be shown by calculating the probability of three failures per year at each load point.

Load Point A: $P[3 \text{ failures/year}] = \frac{(1.35)^3\, e^{-1.35}}{3!} = .106$

Load Point B: $P[3 \text{ failures/year}] = \frac{(1.1)^3\, e^{-1.1}}{3!} = 0.74$

Load Point C: $P[3 \text{ failures/year}] = \frac{(.85)^3\, e^{-8.5}}{3!} = .044$

While the average failure rate at A is 1.35/.85 = 1.6 times more than the rate at C, the probability of three failures is .106/.044 = 2.4 times larger at A than at C. However, the probability of one failure/year occurring is approximately equal for the two load points. Thus, knowing only the average failure rates gives little direct indication of the probabilities of specific numbers of failures in a year. As was shown in the above example, this probability information can be easily calculated using only the average load point failure rate.

Figure 5.2 presents the distributions associated with the failure

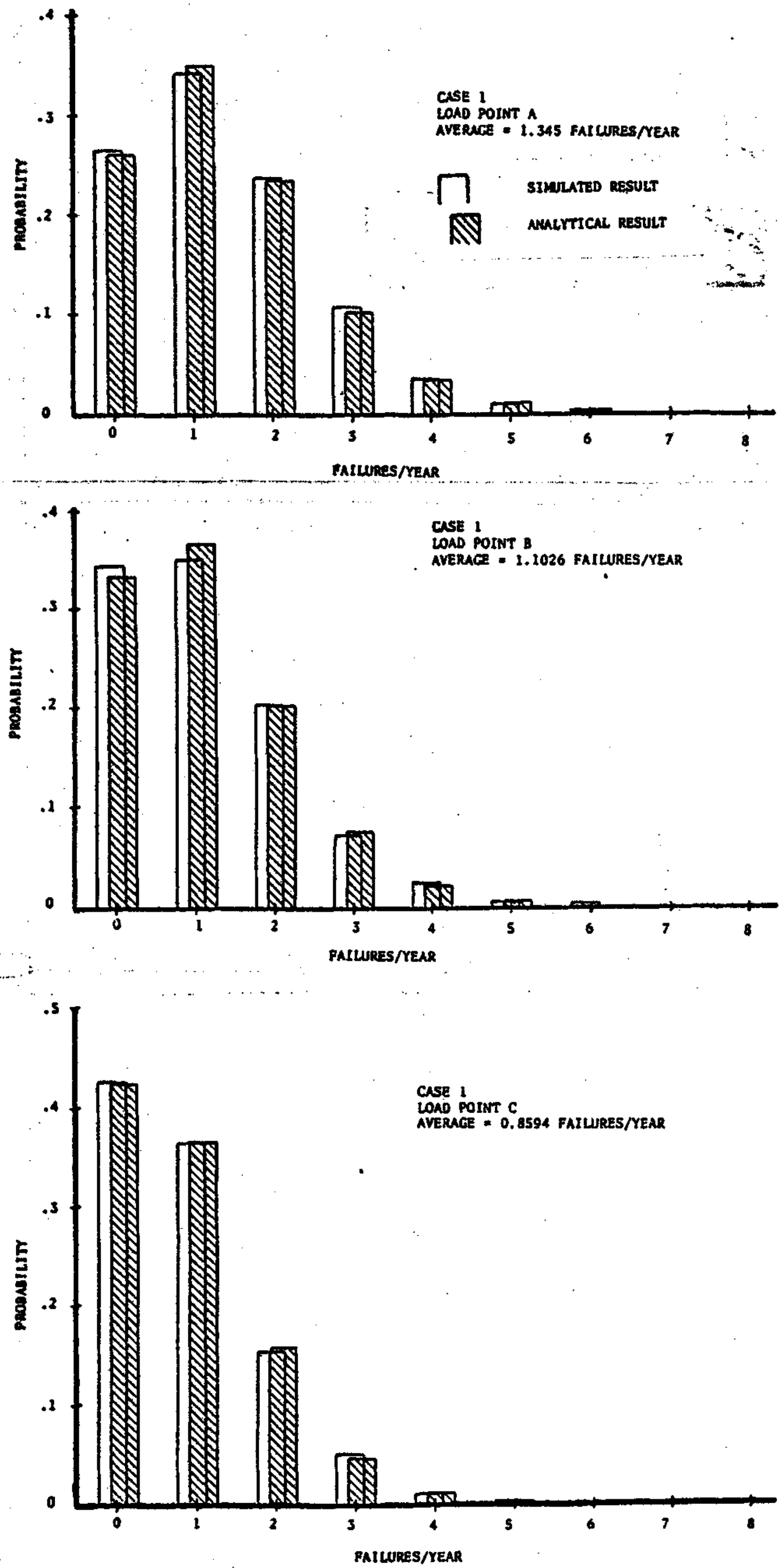


Figure 5.1 Distributions of Load Point Failure Rate
- Restoration Activities Exponentially Distributed

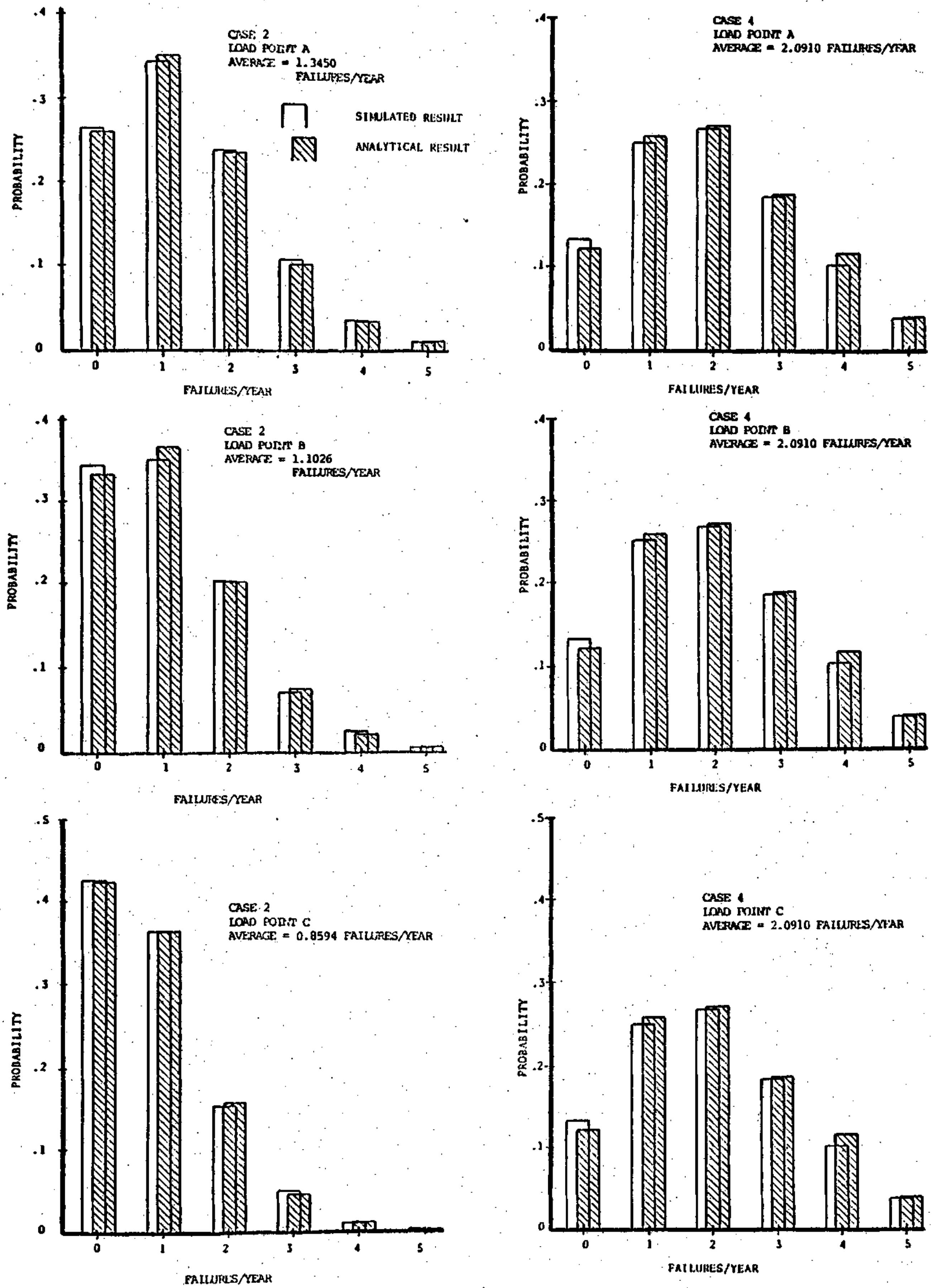


Figure 5.2 Distributions of Load Point Failure Rate
- Restoration Activities Exponentially Distributed

rates of load points A, B and C for Cases 2 and 4. The Case 2 distributions are identical to those for Case 1. As explained in the reliability evaluation section of this thesis, this is due to the fact that backfeeding does not alter the possibility of failures occurring. The Case 4 distributions vary from those of Cases 1 and 2 but are identical for each of the three load points. This is due to each load point suffering a failure when any of the solidly connected laterals suffers a fault. These distributions are identical because the events which bring about the failures are identical. The average failure rate is significantly higher than those of the previous examples and therefore these distributions are even more spread out.

An alternative to repetitively performing the Poisson calculation is to construct graphs from which the probabilistic information can be readily determined. Figure 5.3 shows the probability of R or more failures per year as a function of the average failure rate. The probabilities for a specific R can be found by using the appropriate curve. For a system with a load point failure rate of 2 failures/year:

P [6 or more failures/year] = .016

P [5 or more failures/year] = .053

P [4 or more failures/year] = .143

P [3 or more failures/year] = .322

If the non-cumulative probabilities are desired, only a simple subtraction is necessary.

P [4 failures/year] = P [4 or more] - P [5 or more]

= .143 - .053

= .09

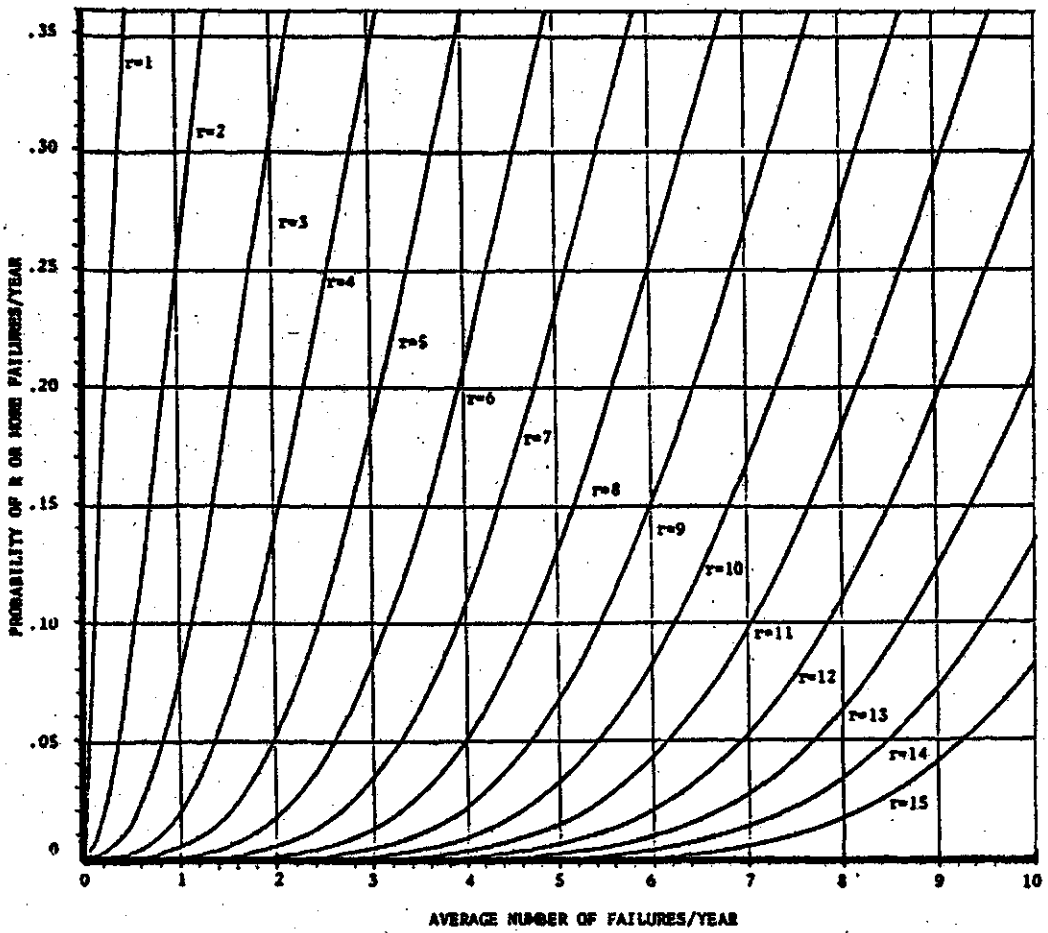


Figure 5.3 Probability of R or more failures/year given average failure rate.

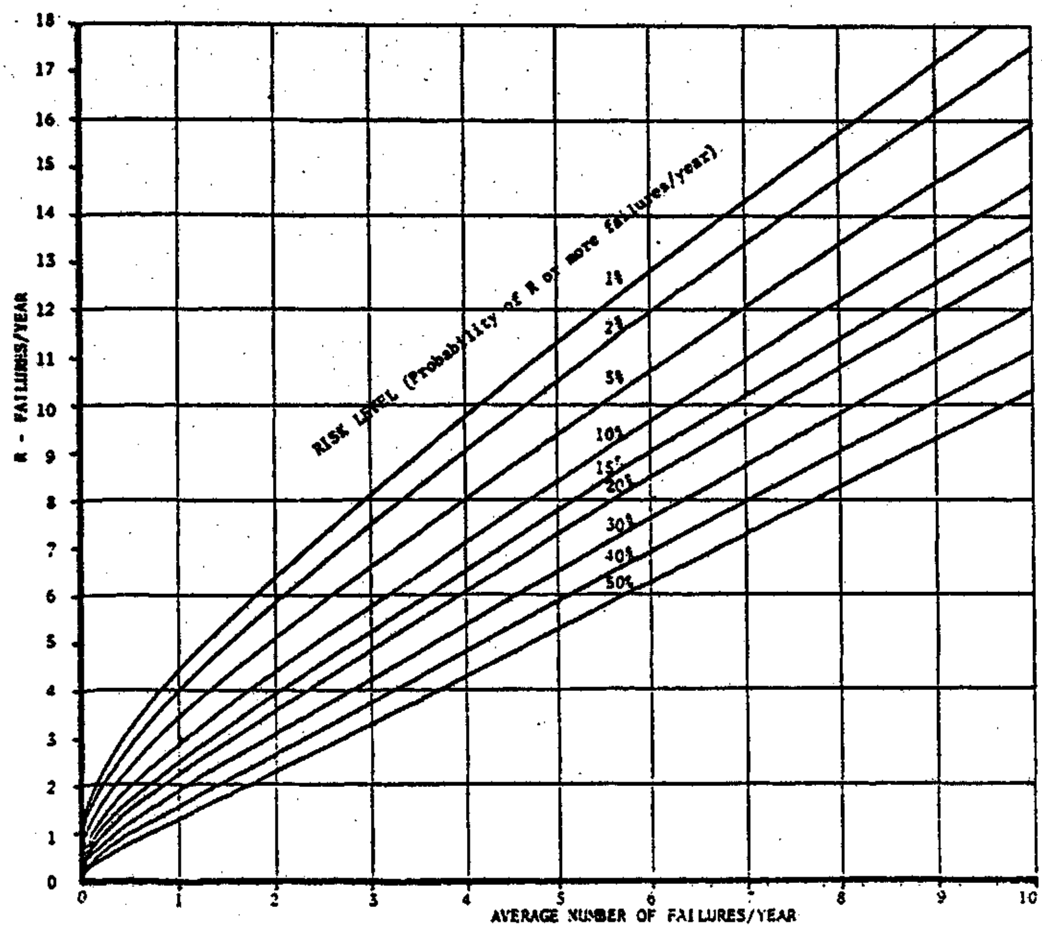


Figure 5.4 Number of failures/year for given risk levels.

Figure 5.4 shows the actual number of failures/year as a function of risk level and of the average number of failures/year. This graph can be used when the user is interested in the maximum number of failures that may occur with a specified risk level. For example; with a risk criterion of 10% and an expected load point failure rate of 3 failures/year, five or more failures occur per year. Since either of the graphs can be used to obtain the same information, the decision as to which to use is a matter of personal preference.

The load point failure rate can be assumed to be Poisson distributed for practical systems because the system failure rate depends only on the component failure rates and not the restoration times. The failure times can be assumed to be exponentially distributed because the components are assumed to be in their operating life. Exponential failure times result in Poisson distributed load point failure rates. Simulation results for the Load Point Failure Rate are not shown for the non-exponential restoration times because they are equivalent to the results for the exponential restoration times.

5.3 Distribution of Load Point Outage Duration

Patton has noted that if repair and other restoration times can be assumed to be exponentially distributed, the load point outage duration can be approximated as being gamma distributed (75). This is confirmed by our studies.

Figure 5.5 plots the simulation results for the outage durations of load points A, B and C for cases 1, 2 and 4 when the restoration times are assumed to be exponentially distributed. These distributions can be

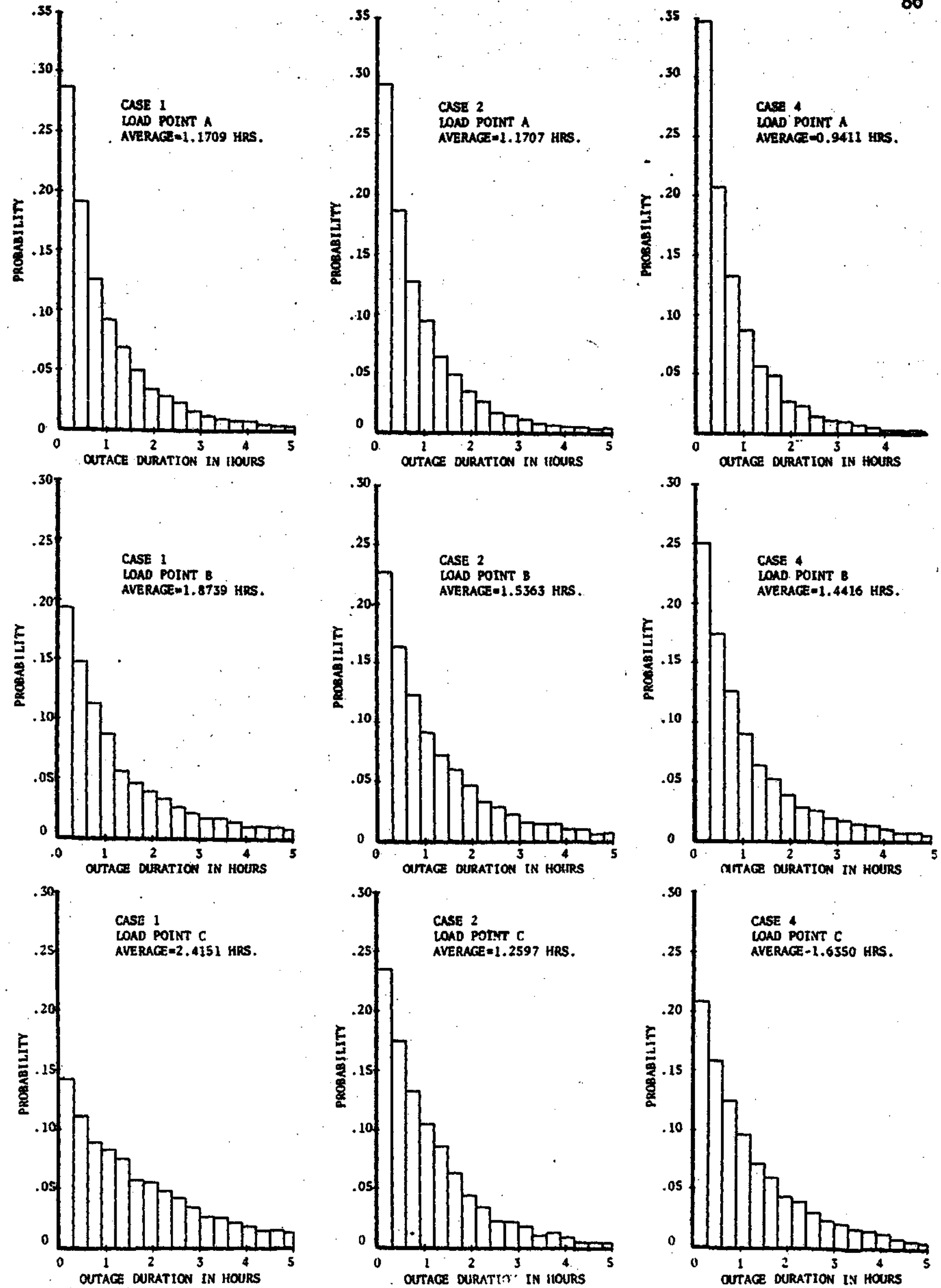


Figure 5.5 Distributions of Load Point Outage Durations
- Restoration Activities Exponentially Distributed (S.D.=mean)

reasonably described by the gamma distribution (Chi-square level of significance = .05). As can be seen, the general shape of the distributions does not vary. Although the gamma distribution can take on much different shapes, when it is the result of combinations of exponential distributions, the shape is always of this general form. The gamma distribution becomes more or less spread out, or more peaked, depending on the average outage durations and the average restoration durations. If it can be assumed that the restoration times are exponentially distributed, the resulting outage duration distribution can be assumed to be of the forms in Figure 5.5 and the outage duration probabilities can be readily calculated from the gamma distribution. Patton describes a relatively simple approach for calculating the gamma distributed duration probabilities using only the average outage durations and failure frequencies of the load points and contributing sections (75). The problem of obtaining access to gamma probability tables is circumvented by utilizing a chi-square transformation and commonly available chi-square tables.

In many practical systems the restoration times cannot be assumed to be exponentially distributed. It is often unrealistic to assume that the probability of a repair or restoration increase as the duration approaches zero. Restoration times may be better described by non-exponential distributions, eg. log-normal repair times. The studies carried out indicate that when the restoration times are assumed to be non-exponential, the load point outage duration cannot generally be represented by a gamma distribution. The remainder of this section will discuss the resulting distributions and how they vary with the following factors:

1) distributions underlying the restoration processes
2) distribution means (ie. the indice values)
3) distribution standard deviations
4) system configuration and operations (ie. cases 1 to 5)
5) position in system
6) size of sections
7) size of system

It should be emphasized that the average values of the load point outage duration indices are not affected by what the underlying distributions are. A set of averages such as those calculated for the example system can have any set of distributions associated with it.

In certain systems it may be possible for one type of restoration activity to consistently occur with durations that are approximately equal. This would imply that the distribution associated with that restoration time could be approximated as a single point (ie. the standard deviation would be zero). Figure 5.6 plots the outage durations for the simulation results when the sectionalizing times are assumed to be fixed with a duration of .5 hours. All the other restoration activities are assumed to be exponentially distributed. It can be seen that for all three cases, load point A has a very pronounced peak for the duration bar of .3 to .6 hours. Load point B has a less pronounced peak while load point C has no peak. The peaks for load point A result from a large number of the outages being due to failures on the second and third primary mains which result in manual sectionalizing activities. Inspection of Table 4.1 shows that for Case 1, .4 failures per year

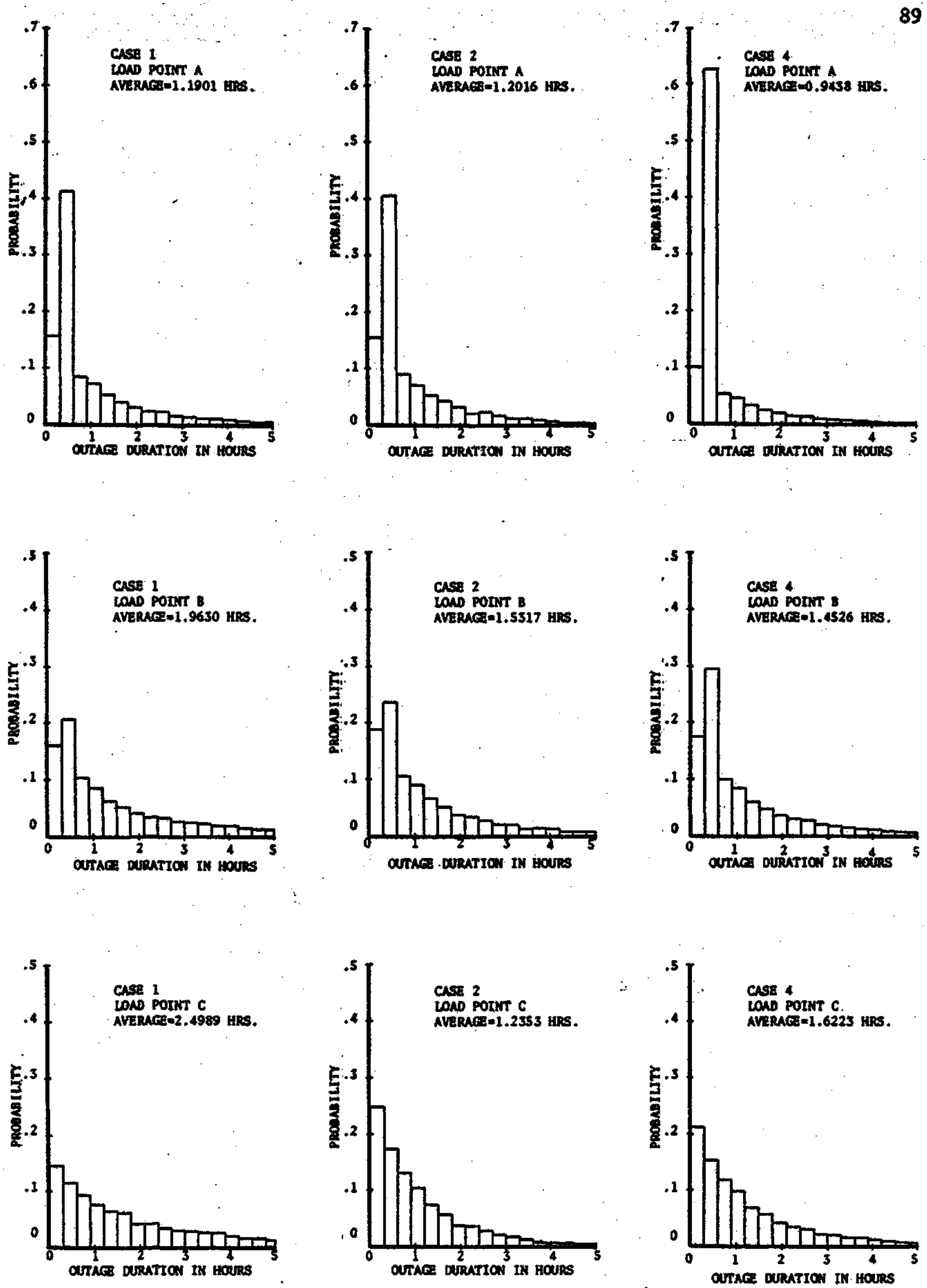


Figure 5.6 Distribution of Load Point Outage Durations
- Manual Sectionalizing Times Fixed

result in half hour sectionalizing activities while .95 failures per year occur which result in exponentially distributed restoration activities. Load point B is further down the line and only failures in the last primary main result in manual sectionalizing. None of the failures contributing to the outage time for load point C result in manual sectionalizing, and thus there is no peak at the half hour duration.

The backfeeding in Case 2 does not alter the impact of the fixed manual sectionalizing times on the distributions. Failures which previously resulted in exponentially distributed repairs now result in exponentially distributed alternate supply switching. The distribution of load point C (and less so B) shifts to the left because the average outage time has been reduced by the backfeed. In Case 4, the effect of the laterals being connected directly to the mains is that a greater portion of the failures contributing to the outage time of load points A and B result in manual sectionalizing. The peaks at .5 hours are proportionately much larger.

The durations associated with repairs and other restoration activities may often be well described by log-normal or other similarily skewed distributions. Figure 5.7 plots the simulation results for the outage durations when repair times are assumed to be log-normally distributed with a standard deviation equal to one third of the mean. These distributions of the load point outage durations have a radically different shape than those assuming exponential restoration times (Figure 5.5). In Case 1, the form of the distribution of load point A appears to be decreasing with duration except for a peak a couple of bars wide. This peak is attributable to the large number of repairs of

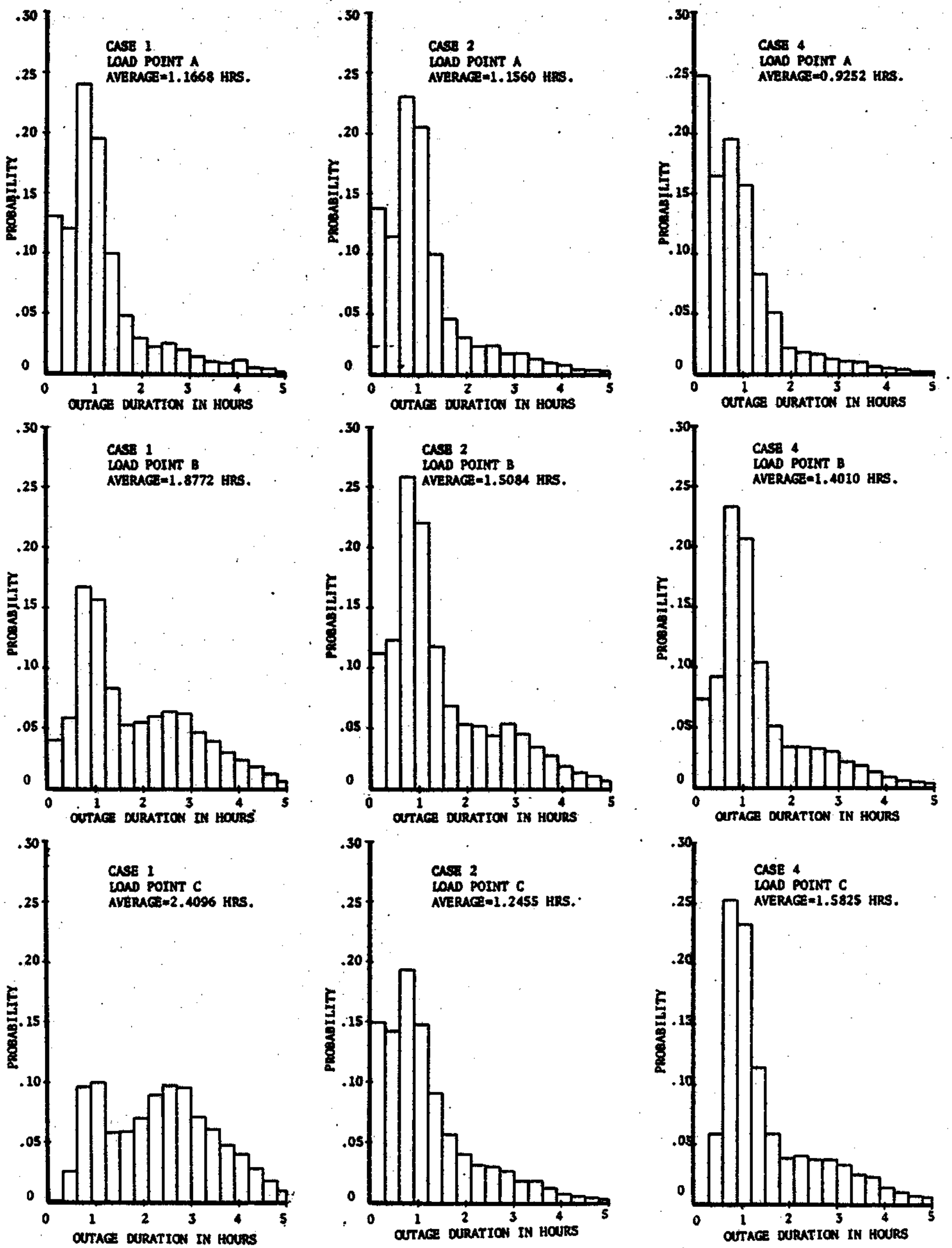


Figure 5.7 Distributions of Load Point Outage Durations
- Repair Times Lognormally Distributed (S.D.=1/3 Mean)
- Other Times Exponentially Distributed (S.D.= Mean)

1 hour average duration which are made on the first primary lateral. Due to it being further down the line, load point C has a larger number of repairs of three hour average duration. These repairs to the mains in combination with repairs to the third lateral result in a bimodal distribution with peaks of durations just less than one and three hours long. Load point B has a distribution that is a combination of those at A and C.

The backfeeding in Case 2 reduces the number of failures with three hour repairs at load point C. The second mode in the distribution is eliminated. The mode resulting from the lateral repairs is now more pronounced for both load points B and C. When the laterals are connected solidly to the mains as in Case 4, the first mode is even more pronounced for all three load points. As indicated in Table 4.7, the predominant cause of outages are failures on the primary laterals resulting in one hour average repairs.

A visual inspection of the distributions in Figure 5.6 or 5.7 indicates that the distributions are so different from those of Figure 5.5 that attempts to predict the duration probabilities using the gamma distribution in these cases of non-exponential restoration times could lead to large errors. Similar results have been obtained from simulations that assumed restoration activities are gamma and normal distributed. This indication is verified by goodness of fit testing (level of significance = .1) and by calculations such as the following example.

Figure 5.8 shows the distribution of interruption duration for load point B of the example system assuming gamma repair and exponential manual sectionalizing times. Two gamma distributions are indicated:

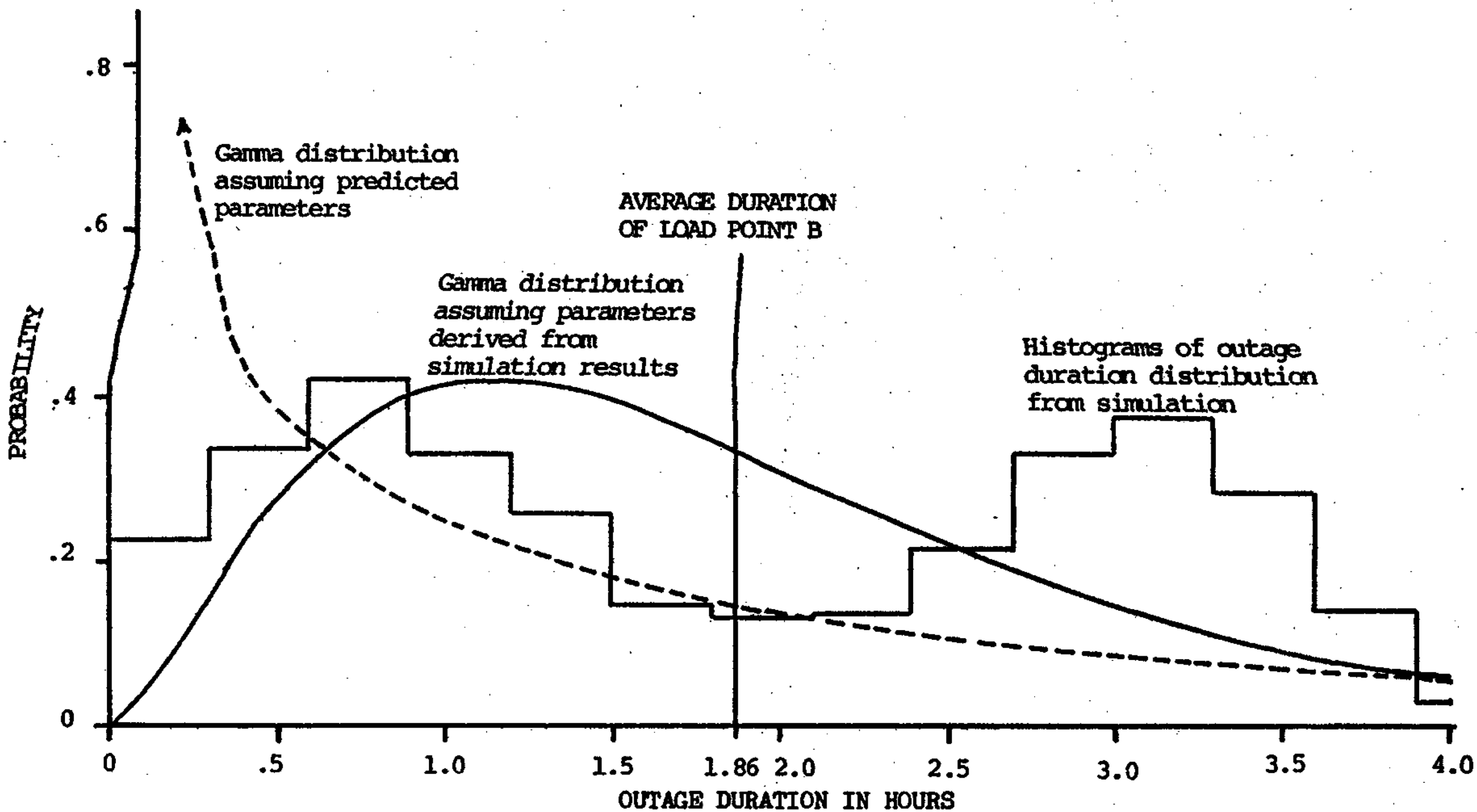


Figure 5.8 Outage Duration Distribution of Load Point B
- Case 1
- Gamma Repair Times (S.D.=.5 hours)
- Other Times Exponentially Distributed (S.D.=m)

one with parameters derived from the mean and variance of the simulation result, the other with parameters predicted using the mean calculated above and the variance calculated with an equation from Patton's simplified approach (75). This equation, which is derived assuming that the restoration times are exponentially distributed, is given in this paper as eq. 5-2.

$$\text{variance } (r_s) = \left(\frac{2}{f_s} \Sigma f_i \overline{r}_i^2\right) - \overline{r}_s^2 \tag{5.2}$$

The gamma probability distribution has the form:

$$f(r) = \frac{\beta^{\alpha} r^{(\alpha-1)} e^{-\beta r}}{\Gamma(\alpha)} \tag{5.3}$$

with the parameters being calculated as:

$$\alpha = \frac{\overline{r}^2}{\sigma_r^2} \tag{5.4}$$

$$\beta = \frac{\overline{r}}{\sigma_r^2} \tag{5.5}$$

The expected value is considerably less than the second modal value. The information that a significant number of outages will be approximately of three hours duration rather than the mean of 1.869 hrs. can be useful in judging the acceptability of that system. The probability of the duration being longer than some value may be desired information. For load point B and conditions as described above, the following probabilities of the duration being longer than 2.1 hours are obtained:

(a) distribution of simulation results:
$P[r > 2.1 \text{ hrs}] = .45$

(b) gamma distribution with parameters obtained from the simulation:
$P[r > 2.1 \text{ hrs.}] = .35$

(c) gamma distribution with parameters obtained using eq. 5.2:
$P[r > 2.1 \text{ hrs.}] = .30$

(d) gamma distribution with parameters obtained using a Chi-Square transformation described in reference 75 which is a simplified method to obtain result (c):
$P[r > 2.1 \text{ hrs.}] = .30$

In this example the error in using approximations, (b,c,d), is significant. In other examples this error could be even greater or insignificant. This example and the other study results indicate that no other known distributions can universally describe the outage duration distributions. Studies of outages duration distributions for entire regions and service areas confirm the reasonableness of this conclusion and the distributions depicted in Fig. 5.7 (77, 79).

As already discussed, varying the means of the restoration times can significantly affect the shape of the outage duration distributions. If the underlying distributions are assumed to be exponential, varying the mean only affects the spread of the distribution not the general shape. If the underlying distributions are assumed to be similar to the lognormal or gamma distributions, the affect is greater. When the different components all have restoration times with averages near to each other and close to the origin, the distribution tends to resemble the exponential. As the differences between the averages increases, the resemblance decreases. The distribution may even be multimodal.

The distributions vary with the associated standard deviations as well as with the component means. Fig. 5.9 plots outage durations for

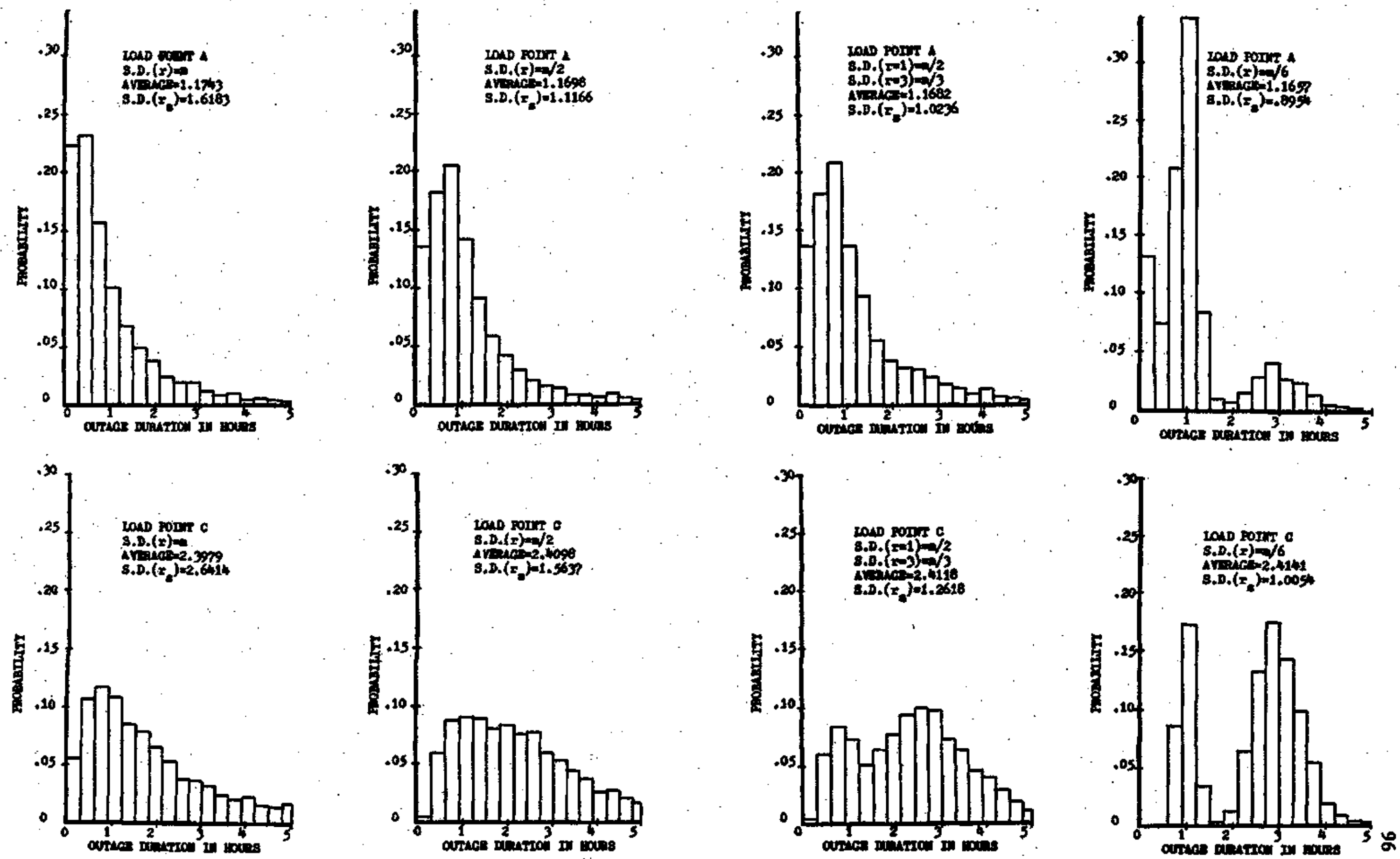


Figure 5.9 Load Point Outage Duration Distributions as a Function of Component Standard Deviations - Repair Times Lognormally Distributed, Case 1

the sample system with the assumptions that the standard deviations for the repair times are equal to m (mttr), m/2, m/3, and m/6. When the standard deviations are relatively large, the contributing distributions overlap with the result that the outage duration distribution is almost a monotonically decreasing function. As the standard deviations decrease, the contributing distributions become apparent and the distribution definitely multimodal.

The sizes of the primary main or lateral sections affect the mean, standard deviation, and possibly the type of the component restoration distribution. The load point outage duration distributions are then indirectly affected by these factors in the ways discussed above. It is possible that the number of sections in the system affects the individual component restoration distributions. A more likely possibility is that the larger number of contributing distributions may tend to overlap more and to obscure modal tendencies that might be apparent in smaller systems. This tendency is most pronounced if the restoration activities of the different system sections are dissimilar.

Simulations were performed for an 18 section system similar to the example system but with 9 load points. Figure 5.10 plots the outage duration probabilities for the first, middle, and last load points of the 18 section system. Visual and statistical comparisons (Chi-Square level of significance = .05) indicate that the outage duration distributions resulting from the assumption of lognormal distributed repair times are significantly different from those resulting from an assumption of exponential distributed repair time. This confirms the conclusion drawn for the smaller 6 section system that the outage duration

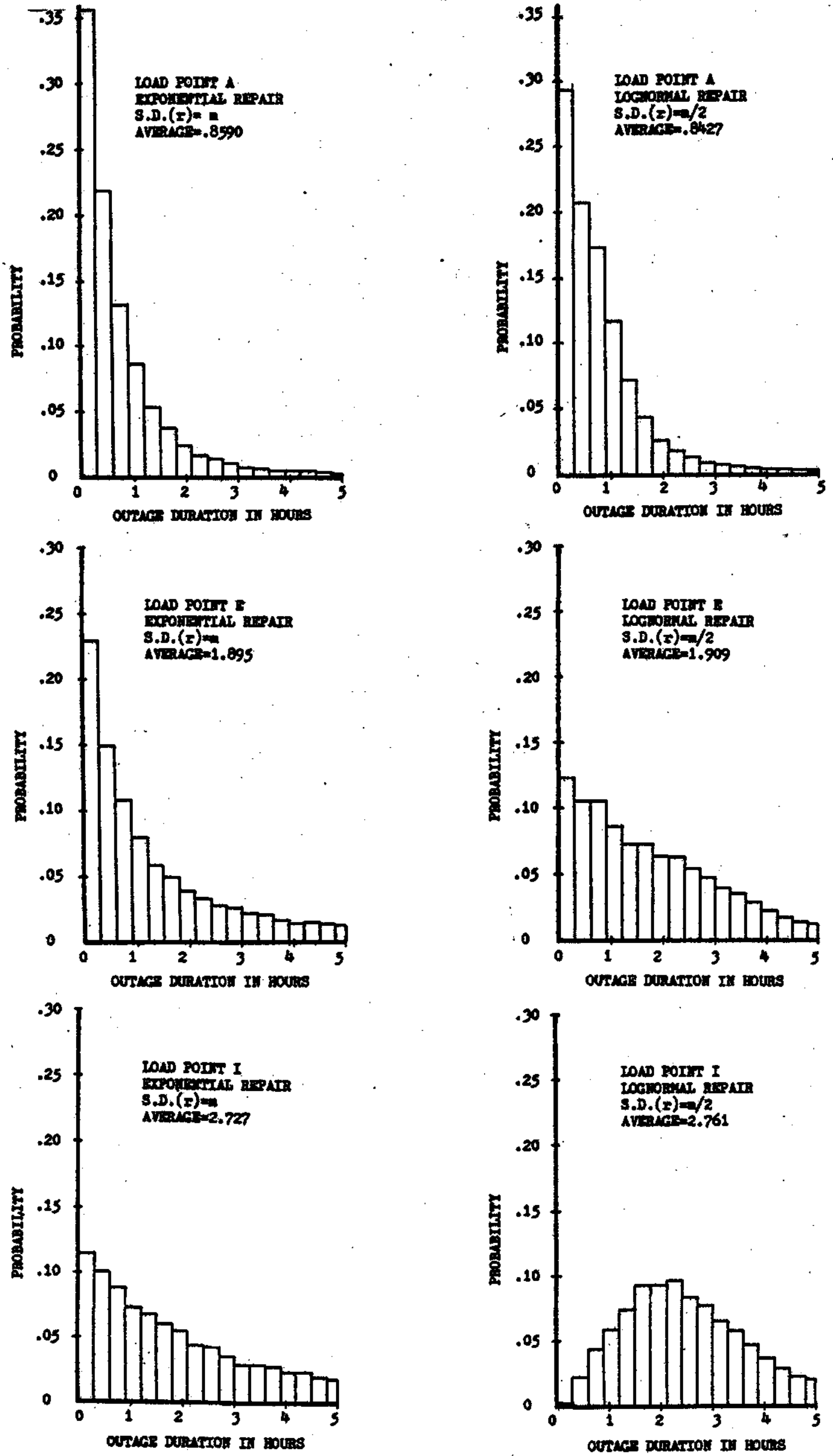


Figure 5.10 Distribution of Outage Durations for 18 Section System - Case 1

distributions cannot in general be described by the gamma distribution computed from the component average repair times.

5.4 Distribution of Other Indices

Sections 5.2 and 5.3 concern the distributions of the Load Point Failure Rate and Outage Duration. This section will briefly describe the following indices:

i) Load Point Annual Interruption Time

ii) CAIDI

iii) SAIDI

iv) SAIFI

5.4.1 Distribution of Load Point Annual Interruption Time

The annual interruption time distribution is dependent on both the failure rate and outage duration distributions. Because of this, it is even more difficult to describe the interruption time distributions by known functions. Figure 5.11 depicts distributions resulting from simulations of the six section example system.

The simulations that assumed exponentially distributed restoration times resulted in annual interruption time distributions that contain a sharp peak for the interval indicating the number of years with no failures. The distributions are steadily decreasing ones with long tails. The distributions are not of the exponential or gamma form.

The simulations that assumed lognormal distributions for the repair times and exponential distributions for the other times also resulted in distributions with a sharp peak for the no failure interval. Inspection

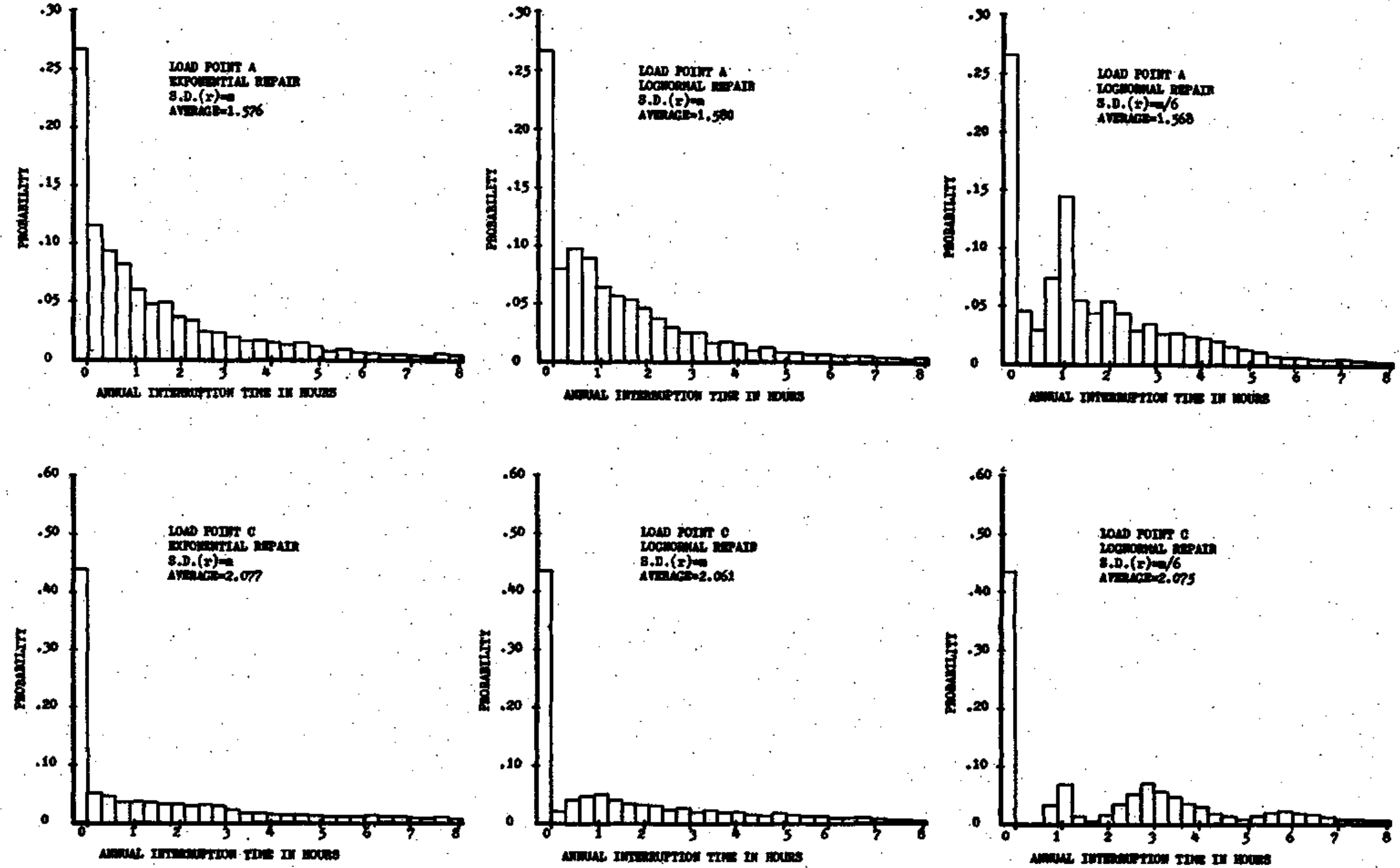


Figure 5.11 Distribution of Annual Interruption Times
- Case 1

of the annual interruption time distributions of all the other case 1, six section system simulations reveals that the number of years with zero hours of interruption is independent of the form and standard deviation of the restoration time distributions. This independence occurs because the number of years with zero interruption time is dominated by the failure rate distributions which determine the number of years in which no failures occur.

The lognormal simulations did not result in steadily decreasing distributions but in distributions with multiple modes. The multiple modality is more prominent when the restoration times are assumed to have small standard deviations. With standard deviations equal to the means, the zero failure peak and a second mode before 1.2 hours are observable. With standard deviations equal to 1/6 means, the zero failure peak and modes about 1.0, 2.0, 3.0, and 6.0 hours are evident. The peaks of certain duration (ie. 2 and 6 hours) are related to years in which more than one interruption occurs and the restoration times are multiples of the dominant modes.

One possible application of the interruption time distribution information involves determining the probability that in a given year the number of hours of interruption is greater than some value. The probabilities that the annual interruption times for load points A and C of the example system are greater than 8.1 hours are derived from the simulations of Fig. 5.11 and presented in Table 5.3. When the repair times are assumed to be lognormally distributed with the standard deviation equal to the mean, the probabilities are fairly close to those when the times are assumed to be exponentially distributed (for which, by definition, standard deviation equals the mean). Reducing the lognormal standard deviation to 1/6 mean, results in the probabilities being significantly reduced:

Table 5.3 Annual Interruption Time Probabilities

	P[annual interruption time>8.1 hrs/yr]	
	Load Point A	Load Point C
Exponential Repair Times	.0262	.0588
Lognormal Repair Times (S.D. = m)	.0218	.0512
Lognormal Repair Times (S.D. = m/6)	.0040	.0260

5.4.2 Distribution of SAIDI, SAIFI, CAIDI

In normal practice, system performance indices and load point reliability indices are not compared or simultaneously calculated. The performance and reliability indices are in reality related by their both being based on a common set of base data. The distributions of the indices are both dependent on the distributions of the component failure rates and the restoration activities. As discussed in Section 5.1, the SAIFI and SAIDI average indices are independent of the underlying distributions but the CAIDI average index is distributionally dependent. The definitions of Section 4.1 are repeated here:

$$\text{SAIDI} = \frac{\text{sum of customer interruption durations}}{\text{total number of customers served}}$$

$$\text{SAIFI} = \frac{\text{total number of customer interruptions}}{\text{total number of customers served}}$$

$$\text{CAIDI} = \frac{\text{sum of customer interruption durations}}{\text{total number of customer interruptions}}$$

Figure 5.12 depicts distributions resulting from simulations of the 6 section example system. The SAIDI distribution is dependent only on

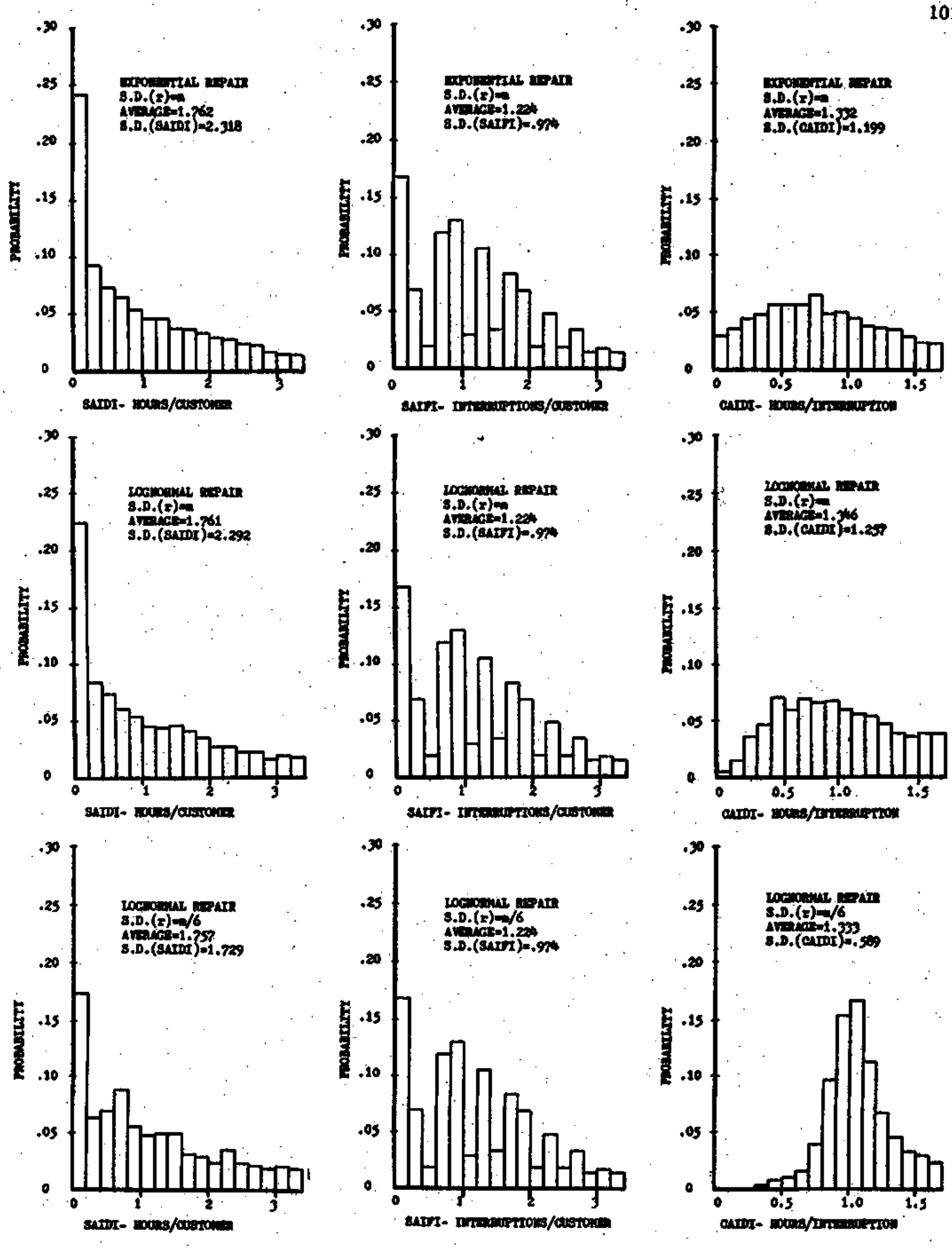


Figure 5.12 Distribution of System Performance Indices - Case 1

the distributions of the restoration times. The number of customers at each load point and the average failure rates are weighting factors that are independent of the associated distributions. The SAIDI distributions of Figure 5.12 are similar to the Annual Interruption Time distributions of Figure 5.11. This is because SAIDI is a linear combination of annual interruption times. In a large system, the resemblance tends to decrease because of the averaging effect of the larger number of load points which are aggregated. Note how in this small system, the number of years with a SAIDI equal to zero is relatively high (ie. P [SAIDI = 0] is high). While in small or moderate systems this is to be expected, when studying the system of an entire region one expects at least a few interruptions.

The SAIFI distributions are identical for the exponential, lognormal S.D. = m, and S.D. = m/6 simulations because SAIFI is only dependent on the component failure time distributions which do not vary with the simulation runs and on the number of customers served at each load point. The irregular variation of the distribution shape is related to the small number of load points and the resulting discrete weighting by the number of customers factor. As for the SAIDI distributions, in large systems the probability of SAIFI equalling zero diminishes with the distribution less resembling an exponential one and more one with a mode about the average.

The CAIDI distributions are non-linearily related to both the failure and restoration times. This results in a somewhat similar modal distribution for the three simulations. The exponential and lognormal S.D. = m simulation distributions are more similar than the lognormal

S.D. = m/6 simulation distribution. This and other comparisons indicate that the standard deviations of the underlying distributions can affect the shape of the final index distribution as much or more than the actual form chosen for the underlying distributions. For large systems the CAIDI distribution also tends to "tighten up" around the mean.

In actual system studies, planners do not have 5000 year histories of their systems nor detailed distributions such as given here. However, with distributional information garnered from simulation studies such as this one and with data on index variation amongst similar regions and utilities for a number of years, planners can perform useful statistical analyses. Some obvious applications would be to compare a systems performance with:

1) that system's performance in other years
2) with a utility's criteria of acceptable performance
3) with the performance of other systems in that utility's service area
4) with the performance of systems or the service area of other utilities.

5.5 Effect of Duration Distributions on Interruption Costs

Interruption costs can vary considerably with the shape of the interruption duration distribution curve. To reduce the amount of computation required however, it is desirable to use the average duration whenever possible rather than to take into account the distribution shape. The error resulting from using only the average is investigated to provide information on when it is reasonable to use only the average interruption duration and when it might be necessary to consider the whole distribution. A series of simulation runs was made with the program described above. The effect of the following factors was investigated:

1) interruption cost curve shape
2) average interruption duration
3) exponential or lognormal distributions of component outage durations
4) standard deviations of the component outage duration distributions

Use of the average interruption duration to calculate interruption costs yields correct answers if the cost function is linear regardless of the interruption duration distribution shape. This is easily shown by the following:

Let: Y = interruption cost

T = interruption duration

f(T) = duration probability density function

m = slope of linear cost line

b = intercept

$Y = mT + b$

Therefore: $\bar{y} = m\bar{t} + b$ using the average duration.

Calculating the cost using the whole range of durations yields the same result.

$$y = \int_{t=0}^{\infty} f(t)\,(mt + b)\,dt$$

$$= m \int_{t=0}^{\infty} f(t)\,t\,dt + b$$

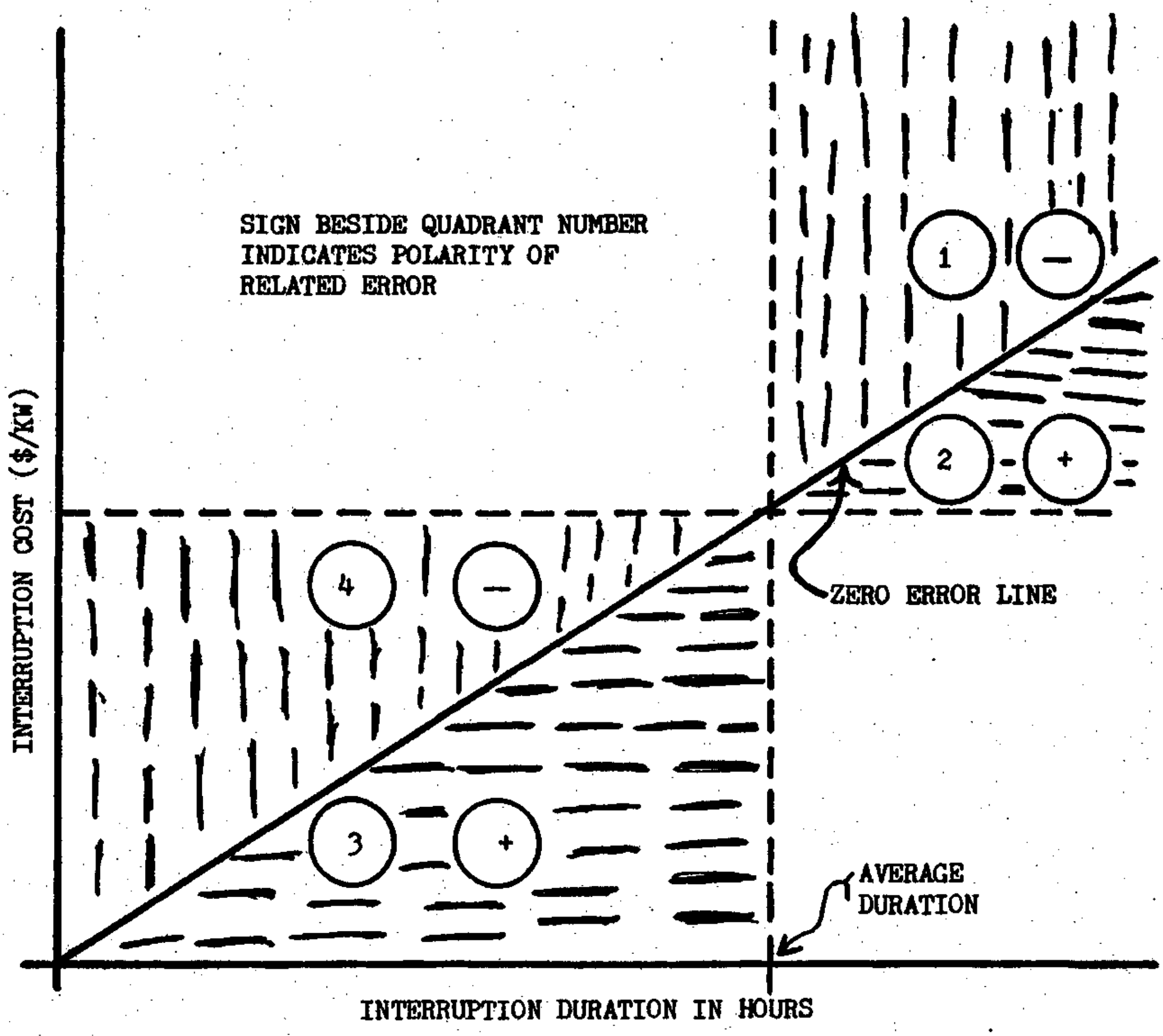
Therefore: $y = m\bar{t} + b$

For non-linear cost functions there is normally some error except for atypical interruption duration distributions such as a point value. The shape of the distribution affects the degree to which the non-linear portions of the cost function contribute to the average cost. The total error is dependent upon where the nonlinearities (eg. break points) occur with respect to the location of the interruption duration distribution (72).

An approach useful in understanding the error mechanism and predicting in a qualitative fashion the error is to compare the interruption cost function of interest with a zero error line. This line would intercept the cost function at the average interruption duration of the load point. The line would be linear and for convenience pass through the origin. Figure 5.13 depicts such a zero error line. The area containing the possible locii of interruption cost functions is divided into four quadrants. Any portions of the cost function which would pass through Quadrants 1 or 4 would contribute a negative error. Similarily portions running through Quadrants 2 or 3 would contribute a positive error. Curves which are linear but do not pass through the origin would be indicated as contributing a negative error on one side and a positive error on the other: a zero error. Of course the zero error line can be rotated about its interception point with the interruption cost function in order to better indicate the likely error.

5.5.1 Simulation Studies of Costing Errors

To investigate the likely magnitudes of error that might result from using average durations, a series of simulations was performed



N.B. ERROR = $\frac{\text{COST USING ONLY AVERAGE DURATION}}{\text{COST USING DURATION DISTRIBUTION}} - 1.0$

Figure 5.13 Cost Distribution Quadrants for Error Analysis using the program introduced previously in Section 5.1. For each interruption occurrence and each load point, the program computes the resulting interruption cost. Amongst other results, the program provides the average yearly cost for each load point. The interruption cost function is inputted as the cost per kw peak demand for 1 minute, 20 minute, 1 hour, 4 hour and 8 hour interruptions. An interruption of zero minutes duration is assumed to have a zero cost while an interruption greater than 8 hours is assumed to result in the same cost as an 8 hour interruption. The costs resulting from interruptions of intermediate duration are computed using linear interpolation. The effect of other assumptions for the zero duration cost, the long duration cost and the intermediate duration interpolation were briefly investigated and found to not significantly affect the results. Had the study included a larger number of interruptions with durations near zero or greater than 8 hours, these assumptions would have had greater effect. Although this program did not include the effect of time of occurrence of interruption, it could be easily modified to do so.

The simulation runs were of the same basic six section system described above in Sections 4.1 and 5.1. All of the interruption cost functions reported by U. of S. (18) and by Ontario Hydro (39 - 46) were analyzed for their general shape. Twenty-three cost functions were chosen to represent the range of shapes. The data for these cost functions is listed in Table 5.4. For each cost function, there were at least two 5000 year runs: one assuming all exponential restoration times and the other all lognormal restoration times. For all the functions, a lognormal run was made assuming a standard deviation equal

Table 5.4 Cost Function Data Used in Simulations

Cost Data Description	Interruption Costs ($kw)				
	1 min	20 min	1 hour	4 hour	8 hour
* Total Small Industrial (U of S)	.70	2.88	5.19	13.87	27.60
Mineral Fuels "	0	0	.39	3.12	7.03
* Furniture Industries "	.01	.22	1.17	2.47	4.10
Chemical Industries "	.63	6.26	6.82	12.03	31.00
Transportation Equipment "	1.33	11.11	20.89	58.57	95.00
Primary Metals "	.05	.30	1.59	3.21	11.95
Printing & Publishing "	.67	2.69	5.52	19.60	64.83
Metal Mines "	.41	1.59	2.94	4.28	6.58
Non Metal Mines "	.19	.73	2.46	7.52	12.12
Metal Fabricating "	3.60	6.97	13.66	41.28	67.27
Paper Industries "	.58	.65	1.00	1.72	2.54
Quarries "	0	.86	4.65	18.61	40.24
* Mining Services "	0	0	13.51	189.19	221.62
* Residential "	0	.06	.31	3.16	4.74
Total Large Users "	1.80	2.22	3.19	6.89	10.47
* Total Commercial "	.28	2.05	5.88	21.51	63.06
* Commercial - SIC 861 "	.03	1.22	7.35	29.01	47.01
* Commercial - SIC 843 "	.17	.68	1.01	10.19	29.92
* Linear & Origin Intercepting	.02	.33	1.00	4.00	8.00
* Non-Metal Mines (Ontario Hydro)	.20	.50	4.80	5.10	6.00
* Total Large Users "	.70	1.70	2.80	6.00	9.00
Petroleum & Chemical "	1.70	2.00	2.70	3.00	4.00
Utilities & Institutional "	.00	.00	.87	3.63	6.02

* indicates cost data plotted on Figures 5.14 and 5.15.

to half the mean while for some cost functions extra runs were made with the standard deviation equal to the mean. The results of other additional runs made with a larger 18 section system and with a mttr for the mains sections of six hours instead of three hours verified the conclusions from the main runs and provided no significant new information. The results of these additional runs will not be reported or discussed.

Table 5.5 tabulates the results from the main runs. Under "RUNS", the table specifies whether the run was for lognormal restoration times with standard deviations equal to mttr/2 (LN), for lognormal restoration times with standard deviations equal to mttr (S.D. = m), or for exponential restoration times (EXP). The "COST DATA" column specifies the interruption cost function data. Under "YEARLY INTERRUPTION COSTS", the table reports: the yearly interruption cost calculated using the average duration (AVG), the yearly interruption cost calculated using the entire duration distribution (DIST), and the error (ERROR) for load points "A" and "C". The yearly interruption costs were calculated assuming that there was at each load point 1000 kw peak demand.

As can be seen in Table 5.5 approximately half of the calculated errors are less than 10%. Most of these can be considered to be zero error since errors of only a few percent can be attributed to statistical variation. While the majority of the remaining errors are less than 25%, a significant number of errors were quite large (ranging from -43% to +80%). The above breakdown is not claimed to be representative of any standard population of users; rather it is intended to provide an indication of the potential range of errors. With a different set of cost curves, durations, and distributions, the error breakdown would likely differ.

Table 5.5 Costing Errors Calculated for Each Simulation Run

RUN #	RUNS	COST DATA	YEARLY INTERRUPTION COSTS					
			LOAD POINT A			LOAD POINT C		
			Avg.	Dist.	Error %	Avg.	Dist.	Error %
103	LN	Total Small Industrial	7,592	7,461	2	7,879	8,021	- 2
104	EXP	(U. of S.)		7,052	8		7,623	3
105	LN	Mineral Fuels	711	850	-16	1,422	1,464	- 3
106	EXP	(U. of S.)		926	-23		1,423	0
107	LN	Furniture Industries	1,667	1,337	25	1,514	1,476	3
108	EXP	(U. of S.)		1,197	39		1,310	16
109	LN	Chemical Industries	9,559	9,974	- 4	7,878	8,504	- 7
110	EXP	(U. of S.)		9,100	5		8,602	- 8
111	LN	Transportation Equip.	30,745	29,942	3	32,810	32,483	1
112	EXP	(U. of S.)		27,710	11		29,672	11
113	LN	Primary Metals	2,256	1,896	19	1,999	2,222	10
114	EXP	(U. of S.)		1,838	23		2,322	14
115	LN	Printing & Publishing	8,402	9,051	- 7	10,317	11,538	-11
116	EXP	(U. of S.)		9,341	-10		12,257	-16
117	LN	Metal Mines	4,059	3,517	15	3,034	3,009	1
118	EXP	(U. of S.)		3,100	31		2,736	11
119	LN	Non-Metal Mines	3,663	3,355	9	4,112	4,021	2
120	EXP	(U. of S.)		3,155	16		3,619	14
121	LN	Metal Fabricating	20,305	20,016	1	22,645	22,391	1
122	EXP	(U. of S.)		19,258	5		20,632	10
123	LN	Paper Industries	1,399	1,302	7	1,138	1,130	1
124	EXP	(U. of S.)		1,255	11		1,063	7
125	LN	Quarries	7,220	7,027	3	9,530	9,701	- 2
126	EXP	(U. of S.)		6,963	4		9,225	3
127	LN	Mining Services	30,097	41,518	-27	81,668	76,063	7
128	EXP	(U. of S.)		43,992	-32		64,712	26
129	LN	Residential	611	796	-23	1,402	1,353	4
130	S.D.= M	(U. of S.)		810	-25		1,194	17
131	EXP			838	-27		1,211	16
132	LN	Total Large Users	4,556	4,476	2	4,190	4,167	1
133	S.D.= M	(U. of S.)		4,385	4		3,945	6
134	EXP			4,350	5		3,922	7
135	LN	Total Commercial	8,993	9,240	- 3	11,242	12,187	- 8
136	S.D.= M	(U. of S.)		9,343	- 4		12,195	- 8
137	EXP			9,392	- 4		12,495	-10
140	LN	Commercial SIC 861	11,385	10,717	6	14,901	14,507	3
141	EXP	(U. of S.)		10,301	11		12,989	15
142	LN	Commercial SIC 843	1,983	3,042	-35	4,526	5,009	-10
143	EXP	(U. of S.)		3,472	-43		5,307	-15
138	LN	Linear & Origin	1,553	1,571	- 1	2,049	2,069	- 1
139	EXP	Intercepting		1,539	1		1,949	5
101	LN	Large Non-Metal Mines	6,500	4,352	49	4,200	3,950	6
102	S.D.= M	(Ontario Hydro)		3,701	76		3,537	19
33	EXP			3,603	80		3,272	28
29	EXP	Total Large Users	3,996	3,499	14	3,658	3,314	10
30	LN	(Ontario Hydro)		3,719	7		3,613	1
31	EXP	Petroleum & Chemical	3,665	3,159	16	2,415	2,310	5
32	LN	(Ontario Hydro)		3,310	11		2,418	0
35	EXP	Utilities & Insti.	1,361	1,204	8	1,842	1,597	15
36	LN	(Ontario Hydro)		1,265	8		1,788	3

Error = [(Average Cost/Distributed Cost) - 1.0] x 100

5.5.2 Comparison of Errors - Simulation And Quadrant Analysis

The errors calculated from the simulations can be compared with the predictions resulting from performing the quadrant analysis depicted in Figure 5.13. First the cost curves are normalized by dividing the data by values which would cause all of the curves to intersect at the average load point outage duration. Ten of the twenty-eight curves are plotted in Figure 5.14 for the 1.15 hour average duration of Load Point A and in Figure 5.15 for the 2.41 hour average duration of Load Point C. Any data points equal to zero are plotted as being equal to .0001 \$/kw since log-log graphs are used. Table 5.6 contains the predictions which are obtained using the graphs. The predictions are subjectively derived by assigning for the LHS or RHS:

1) a "+" if that portion of the curve contributes a positive error
2) a "-" if that portion of the curve contributes a negative error
3) a "0" if the error is negligible or if it was not predictable because the cost function crossed the zero error line in that side of the graph.

The table also contains the sum of the predictions and the errors calculated from the simulations assuming exponentially distributed restoration time and from the simulation assuming lognormally distributed restoration times. There is a strong correlation between the predictions and the calculations in that when the sum is "-" or "--" the error is negative and when the sum is "+" or "++" the error is positive. When the sum is "0" the errors tend to be quite small. There are exceptions to this tendency because of the subjective nature of the predictions. The main problem is that no account is taken of magnitude when

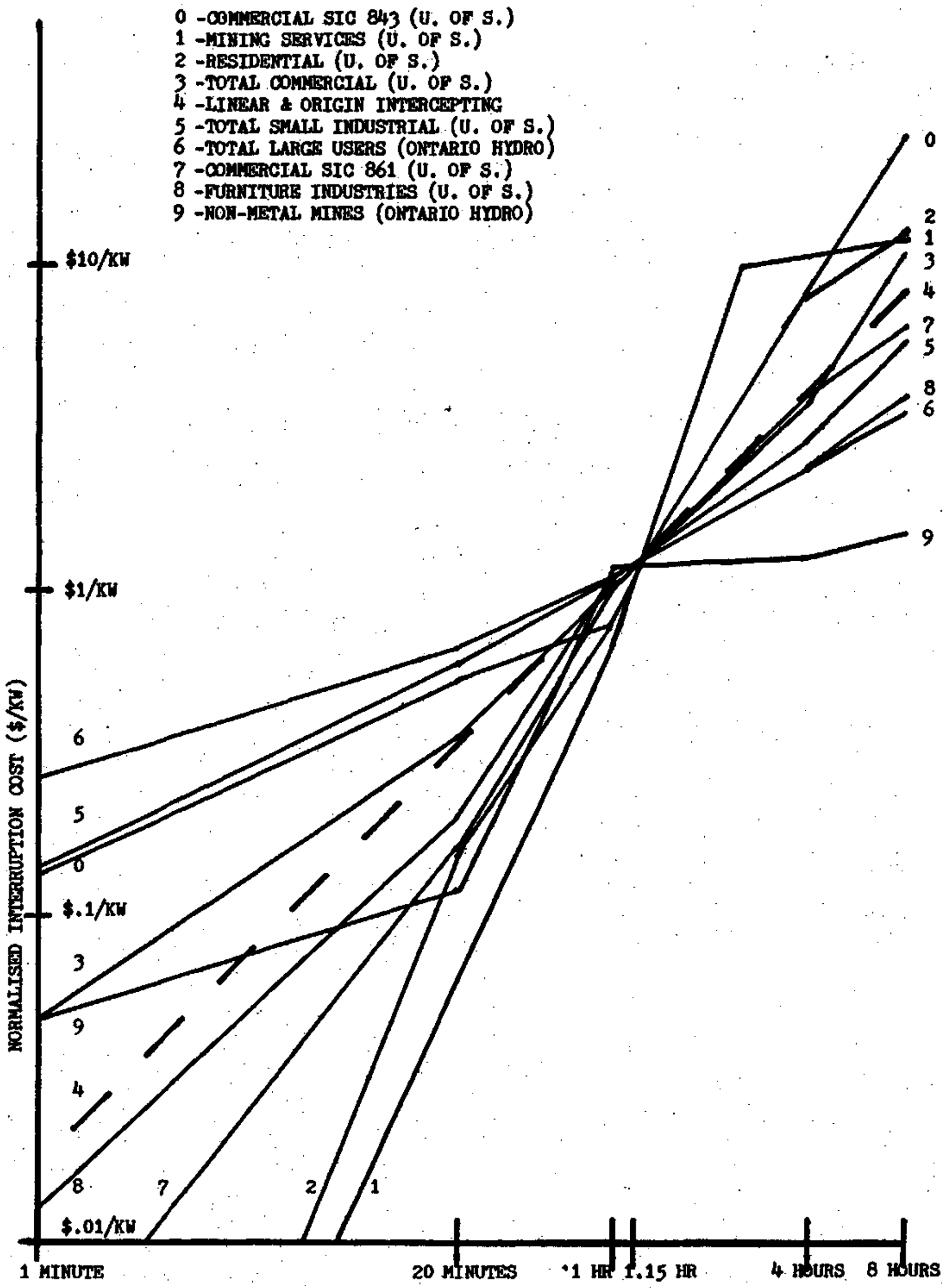


Figure 5.14 Cost Functions Normalised to 1.15 Hours Cost

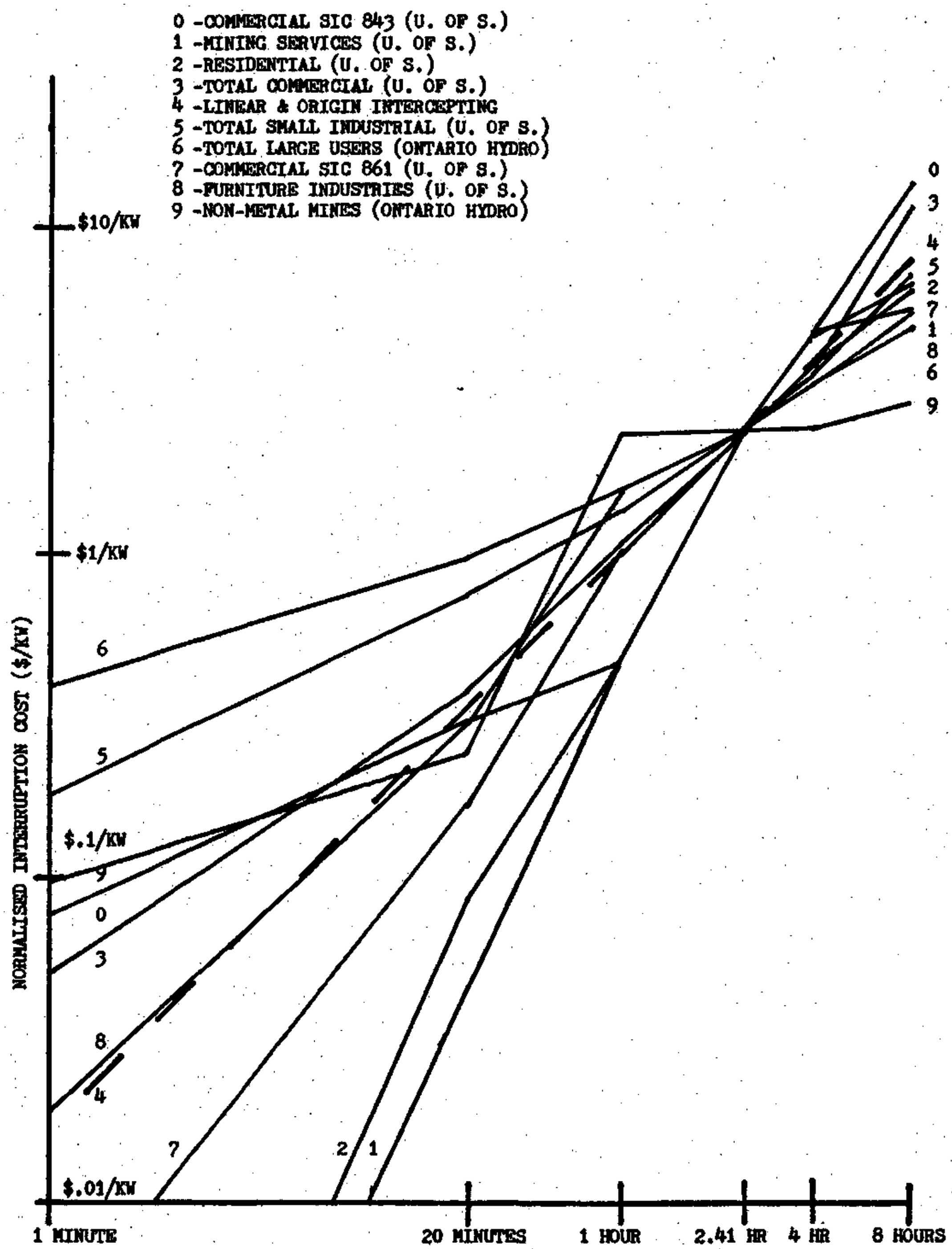


Figure 5.15 Cost Functions Normalised to 2.41 Hours Cost

Table 5.6 Comparison of Calculated and Predicted Costing Errors

Curve	Load Point	Sign of Predicted Error			Calculated Error	
		LHS	RHS	Sum	Exponential	Lognormal
0	A	-	-	--	-43	-35
	B	0	-	-	-15	-10
1	A	+	-	0	-32	-27
	B	+	0	+	26	7
2	A	+	-	0	-27	-23
	B	+	0	+	16	4
3	A	-	0	-	- 4	- 3
	B	-	-	--	-10	- 8
4	A	0	0	0	1	- 1
	B	0	0	0	5	- 1
5	A	-	+	0	8	2
	B	-	+	0	3	- 2
6	A	-	+	0	7	14
	B	-	+	0	1	10
7	A	+	+	++	11	6
	B	+	+	++	15	3
8	A	+	+	++	39	25
	B	0	+	+	16	3
9	A	+	+	++	80	49
	B	0	+	+	28	6

summing a prediction associated with a large error and a prediction associated with a small error of the opposite polarity. The most notable examples of this are the sums for Load Point A of curves 1 and 2. The sums are zero but the simulation calculations result in a significant negative error. The comparisons for these ten curves and the other eighteen curves confirms that a quadrant analysis could be used to give a subjective yet fairly reliable qualitative indicator of the error likely resulting from using the average value instead of the entire duration distribution.

5.5.3 Effect of Cost Curves and Duration Distributions

The errors can be compared to investigate the effect of cost curve shape, average interruption duration, the associated standard deviation of duration, and exponential or lognormal distributions. As was indicated earlier, using the average interruption duration instead of the range of durations can result in significant error when the cost curve is non-linear. Inspection of the cost data in Table 5.4 and the errors in Table 5.5 is facilitated by plotting the curves. Because of the range of costs and durations involved it is convenient to use the log-log plots of Figures 5.14 and 5.15 but it must be remembered that linear data plot perfectly as straight lines only when they have slopes of zero, one or infinity. Inspection of the curves in Figure 5.14 and 5.15 and the other cost data in Table 5.5 reveals that the error is negligible for cost curves which are linear and that the error increases with the degree of non-linearity. Curves (such as for the total commercial, total small industry, or total large users sample) which are aggregates of the costs of many smaller and different user groups tend to be linear and have a small error. Curves which are for more specific groups of users with similar characteristics (such as for commercial SIC 843 or large non-metal mines) tend to have sharper break points, be more non-linear, and have larger errors. Because of the smoothing and linearizing effect resulting from aggregating types of users, there is likely less error involved in using only average durations when performing calculations for generation or composite reliability studies than for distribution reliability studies.

The main effect of varying the average interruption duration is to change the location of the interruption duration distribution with respect to the cost curve break points and non-linearities. Thus, varying the average duration can act to increase or decrease the percentage error. All other factors being equal, the error due to using only the average duration tends to increase with the standard deviation associated with the interruption duration distribution. With a negligible standard deviation, the cost estimated from the average duration would be the true cost because the whole distribution would be located at that average value. The shape of the distribution affects the degree to which the non-linear portions of the cost function contribute to the average cost. In most of the sets of runs, the ones assuming exponentially distributed restoration times yielded greater errors than the ones assuming lognormally distributed times. Much of this difference in error can be attributed to the fact that the exponential distribution by definition has a standard deviation equal to the mean while most of the log normal distribution runs assumed a standard deviation equal to one half the mean. The lognormal runs that assumed a standard deviation equal to the mean yielded errors comparable to those of the exponential runs.

5.6 Comparison of $/KWHR and $/KW Coefficient Forms

Interruption cost coefficients take two basic forms: $/KW and $/KWHR. The $/KW form refers to dollar cost per unit of electric peak demand not supplied and usually is given as different values for different durations. The $/KWHR form refers to dollar cost per unit of electric energy not supplied and usually is assumed to not vary with interruption duration. An exception to this occurs when a $/KWHR coefficient is synthesized from cost coefficients that are functions of durations. Expected frequency and duration information is used to weigh the various coefficients into a single $/KWHR value.

As discussed in Chapter 2, some interruption costing methodologies result in $/KWHR estimates, some result in $/KW estimates and many can result in either form. In addition to having an understanding of the characteristics and validity of each costing methodology, it would also be useful to have an understanding of the differences that result from the forms themselves.

One approach to investigating the differences between the two forms is to study the errors in calculated interruption cost that result from varying the interruption duration but assuming that the costs change in a linear fashion. The underlying reasoning is as follows. When calculating interruption cost with the $/KWHR coefficient, the coefficient is multiplied by the expected energy not supplied. The interruption durations and frequencies while not accounted for and possibly not known could be any practical combination that results in the same EENS product. Since the cost often varies non-linearly with duration, the estimated cost could be in error. Table 5.7 tabulates the calculations for a set of example calculations. Assume that the expected energy not supplied at a load point for a year is 1 MWHR and that the demand is constant throughout that period at 1 MW. This value of EENS could result from many different combinations of interruption duration and frequency. Three example scenarios are: sixty 1 minute interruptions, three 20 minute interruptions, or one 1 hour interruption. The table presents the cost estimates resulting from the use of Ontario Hydro interruption cost coefficients for the Large User sector (39). The calculated cost varies dramatically with the chosen scenario. Had a $/KWHR coefficient been used the cost would not have varied with the scenarios. Obviously applying a $/KWHR cost coefficient and ignoring variation with duration can result in large errors.

There is no viable method to determine the $/KWHR equivalent of $/KW data without assuming a fixed interruption scenario. Thus the absolute error involved in using $/KWHR data cannot be directly calculated. However a useful indication of the potential errors involved can be obtained by comparing for a range of typical $/KW cost data, the costs calculated for typical durations. The data presented previously in Table 5.5 can easily be used for such a study. Table 5.8 summarizes the indices for Load Points A and C of the example six section system. These two load point calculations were chosen because their average durations encompass the typical CAIDI values reported by utilities in

Table 5.7 Effect of Constant EENS But Varying F & D

	Interruption Scenario		
	Sixty 1 Min. Interruptions	Three 20 Min. Interruptions	One 1 Hour Interruption
EENS	1 MWHR	1 MWHR	1 MWHR
Cost Coefficient OH Large Users	$.70/KW	$1.70/KW	$2.80/KW
Cost Per Interruption	$700	$1,700	$2,800
Total Calculated Cost	$42,000	$5,100	$2,800

Table 5.8 Index Summary

Interruption Indices	Load Point A	Load Point C
failures/year	1.35	.85
hours/failure	1.15	2.41
hours/year	1.55	2.05

the CEA distribution service continuity reports (87). As Table 5.7 shows, the relative error can be quite large when greatly different durations are being considered. Comparing the costs for durations which are relatively close is of more practical significance.

Since load is assumed constant, the EENS is proportional to U (hours of interruption per year). The costs calculated with $/KWHR coefficients would thus be proportional to the hours of interruption per year. The ratio of U_{LPC}/U_{LPA} can be compared with C_{LPC}/C_{LPA} (ratio of costs calculated using the duration data) to indicate the relative error that would result from using the $/KWHR data.

Table 5.9 tabulates the calculated errors. The first listing is used as an example. The Load Point A average cost of $7,592 is calculated from the 1.15 hrs. average interruption duration, 1.35 f/year average interruption frequency, 1,000 KW load, and the small industrial cost coefficients. The Load Point C cost of $7,879 is similarly calculated. The ratio of hours of interrution per year for the two load points is divided by the ratio of costs to yield the relative error. The 27% average error indicates that $/KWHR data would have resulted in a 27% greater cost difference than if the duration specific $/KW data had been used. The last column contains relative errors calculated in the same way as above except that the entire distribution of durations obtained by the simulation are used to calculate costs instead of just the average duration.

The errors calculated using the average durations, the distribution of durations from the exponential restoration time simulations, and the distribution of durations from the lognormal restoration time simulations correlated. The errors associated with the duration distributions tended to be somewhat smaller because of the "smoothing" effect resulting from distributed values instead of a single point value. While a large number of the cost data sets resulted in small or negligible errors, many sets resulted in significant or quite large errors. This indicates that the use of the $/KWHR data form can result in large and unacceptable errors.

Table 5.9 Costing Errors Resulting from Assuming a Linear Cost Function Similar to $/KWHR

RUN #	RUNS	COST DATA	YEARLY INTERRUPTION COST				RELATIVE ERROR RESULTING FROM ASSUMING LINEAR COST DATA	
			LOAD POINT A		LOAD POINT C			
			Avg.	Dist.	Avg.	Dist.	% Error (Avg)	% Error (Dist)
103	LN	Total Small Industrial	7,592	7,461	7,879	8,021		23
104	EXP	(U. of S.)		7,052		7,623	27	22
105	LN	Mineral Fuels	711	850	1,422	1,464		-23
106	EXP	(U. of S.)		926		1,423	- 34	-14
107	LN	Furniture Industries	1,667	1,337	1,514	1,476		20
108	EXP	(U. of S.)		1,197		1,310	46	21
109	LN	Chemical Industries	9,559	9,974	7,878	8,504		55
110	EXP	(U. of S.)		9,100		8,602	60	40
111	LN	Transportation Equip.	30,745	29,942	32,810	32,483		22
112	EXP	(U. of S.)		27,710		29,672	24	24
113	LN	Primary Metals	2,256	1,896	1,999	2,222		13
114	EXP	(U. of S.)		1,838		2,322	49	5
115	LN	Printing & Publishing	8,402	9,051	10,317	11,538		4
116	EXP	(U. of S.)		9,341		12,257	8	1
117	LN	Metal Mines	4,059	3,517	3,034	3,009		55
118	EXP	(U. of S.)		3,100		2,736	77	50
119	LN	Non-Metal Mines	3,663	3,355	4,112	4,021		11
120	EXP	(U. of S.)		3,155		3,619	18	15
121	LN	Metal Fabricating	20,305	20,016	22,645	22,391		18
122	EXP	(U. of S.)		19,258		20,632	19	23
123	LN	Paper Industries	1,399	1,302	1,138	1,130		53
124	EXP	(U. of S.)		1,255		1,063	63	56
125	LN	Quarries	7,220	7,027	9,530	9,701		- 5
126	EXP	(U. of S.)		6,963		9,225	0	0
127	LN	Mining Services	30,097	41,518	81,668	76,063		-28
128	EXP	(U. of S.)		43,992		64,712	- 51	-10
129	LN	Residential	611	796	1,402	1,353		-22
130	S.D.= M	(U. of S.)		810		1,194		-10
131	EXP			838		1,211	- 42	- 8
132	LN	Total Large Users	4,556	4,476	4,190	4,167		42
133	S.D.= M	(U. of S.)		4,385		3,945		47
134	EXP			4,350		3,922	44	47
135	LN	Total Commercial	8,993	9,240	11,242	12,187		0
136	S.D.= M	(U. of S.)		9,343		12,195		1
137	EXP			9,392		12,495	6	- 1
140	LN	Commercial SIC 861	11,385	10,717	14,901	14,507		- 2
141	EXP	(U. of S.)		10,301		12,989	1	5
142	LN	Commercial SIC 843	1,983	3,042	4,526	5,009		-20
143	EXP	(U. of S.)		3,472		5,307	- 42	-13
138	LN	Linear & Origin	1,553	1,571	2,049	2,069		0
139	EXP	Intercepting		1,539		1,949	0	4
101	LN	Large Non-Metal Mines	6,500	4,352	4,200	3,950		46
102	S.D.= M	(Ontario Hydro)		3,701		3,537		38
33	EXP			3,603		3,272	105	46
29	EXP	Total Large Users	3,996	3,499	3,658	3,314		40
30	LN	(Ontario Hydro)		3,719		3,613	44	36
31	EXP	Petroleum & Chemical	3,665	3,159	2,415	2,310		81
32	LN	(Ontario Hydro)		3,310		2,418	101	81
35	EXP	Utilities & Insti.	1,361	1,204	1,842	1,597		0
36	LN	(Ontario Hydro)		1,265		1,788	- 2	- 6

$$\% \text{ Error} = \left(\frac{U_{lpc} / U_{lpa}}{COST_{lpc} / COST_{lpa}} - 1.0 \right) X\ 100$$

The error can be even larger than indicated by Table 5.9. The interruption cost function nonlinearity and resulting error tend to increase as the difference in duration increases. Second, the cost function nonlinearity is not the only source of error. The $/KWHR data assumes a cost function that passes through the origin. Since most users however experience a significant cost for even a very short momentary interruption, the error can be even larger. If the cost coefficient includes a cost per interruption term as well as the cost per KWHR term, then only the error resulting from cost function nonlinearity would be present.

It can be concluded that the $/KWHR coefficient form is inappropriate when computing interruption costs at distribution load points. These load points are usually dominated by only a single or few types of users. At composite system load points, the user composition is much more varied. Usually aggregating user cost data types results in a more linear cost function. In that case the error resulting from nonlinearity is diminished and only the error related to the cost function zero intercept remains. If, like the IEEE cost data (16, 17), the cost function includes a per interruption component then the error may be negligible or at least acceptible when being applied at a load point with much user type diversity.

All of the above discussion on error concerns only the form of the $/KWHR data. The methodology used to obtain the data may introduce even larger errors.

5.7 Analytical Construction of Load Point Index Distributions

When performing reliability studies or reliability cost benefit analyses, a deterrent to the use of index distributions is the CPU time requirements to perform simulations. One alternate approach to obtain the load point outage duration distribution is to assume that all the underlying distributions are exponential and employ Pattons' simplified equations for the Gamma distribution (75). An attendant problem is the possibility of significant errors. An alternative approach which would involve negligible error and little CPU time is to analytically construct the load point indice distributions without resorting to simulations. Table 5.10 present the CPU times for the simulation runs on a DEC 2060 computer and for the calculation times of an analytical construction program run on a Texas Instruments 58 calculator. While the analytical construction approach does not yield the same amount of information as the simulation approach, the computing cost is much less.

This section discusses an approach to analytically construct the distributions for the load point outage durations and annual interruption time indices. Load point outage duration distributions produced by a TI58/59 calculator program are presented. The outage duration distributions were produced rather than the annual interruption time distributions because the duration distributions are the most useful distributions and because they are much easier to produce than the interruption time distributions. The Poisson distributions of the load point failure rate can be easily obtained from the Poisson equation. The SAIFI and SAIDI system performance indices are more difficult to obtain by the suggested analytical approach while CAIDI may be impossible.

Table 5.10 Calculation Time Requirements

Type of Calculation	# of Years	Number of Load Points	Out-Put*	Calculation Time Min : Sec
Simulation Program:				
Lognormal Restoration Times	5000	2	all	1:56
Exponential Restoration Times	5000	2	all	1:53
Lognormal Restoration Times	1000	3	all	:47
Exponential Restoration Times	1000	3	all	:46
Lognormal Restoration Times	5000	3	all	2:55
Exponential Restoration Times	5000	3	all	2:45
Lognormal Restoration Times	5000	3	partial	1:49
Lognormal Restoration Times	1000	3	partial	:27
Lognormal Restoration Times	5000	9	all	18:40
Exponential Restoration Times	5000	9	all	18:02
T1:58/59 Program:				
Lognormal Restoration Times	N.A.	1	outage duration	15:00
Exponential Restoration Times	N.A.	1	outage duration	13:00

* NOTE: For the simulation program: "All" implies the distribution histograms for the load point indices, the load point interruption costs and the system performance indices while "partial" implies only the histograms for the load point indices. The TI58/59 program time is for the distribution of the load point outage duration for 1 load point and includes the time for the operator to input and output data.

5.7.1 Derivation of Analytical Formula for Load Point Outage Duration

A formula describing the distribution of the interruption duration can be obtained from an inspection of the probabilistic mechanics involved. The qualifying assumptions are ones that are commonly made in distribution system reliability evaluation:

1) system is in the down state much less than in the up state and no load point interruption is caused by the failure of more than one component.
2) component failures are independent of each other.
3) for each component, the time-to-failure density function and time-to-repair density function are independent.

Let i indicate any component i which can affect the load point of interest

r_i = interruption duration due to component i

λ_i = failure rate of component i

λ_s = $\Sigma\lambda_i$ = failure rate of the load point

Given that a failure has occurred:

P[R=r] = probability that the interruption duration will equal r hours

$$= \Sigma_i \text{ P[component i failed] } P[R_i=r]$$

$$P[R=r] = \frac{\Sigma_i \quad \lambda_i \quad P[R_i=r]}{\lambda_s} \tag{5-6}$$

To obtain the probability density function for the load point interruption duration $f_R(r)$:

$$f_R(r) = \frac{\Sigma_i \quad \lambda_i \quad f_{Ri}(r)}{\lambda_s} \tag{5-7}$$

The interval probability form of Eq. (5-6) is

$$P[r_1 < R \leq r_2] = \frac{\Sigma_i \quad \lambda_i \; P[r_1 < R_i < r_2]}{\lambda_s} \tag{5-8}$$

The basic equation for the average interruption duration can be obtained.

$$r_s = \text{expected interruption duration}$$

$$= E[R]$$

$$= \int_{-\infty}^{\infty} r\, f_R(r)\, dr$$

$$= \int_{-\infty}^{\infty} r\, \frac{\Sigma \lambda_i\, f_{Ri}(r)}{\lambda_s}\, dr$$

$$= \frac{\Sigma_i\ \lambda_i}{\lambda_s} \int_{-\infty}^{\infty} r\, f_{Ri}(r)\, dr$$

$$\therefore r_s = \frac{\Sigma_i\ \lambda_i\ E[R_i]}{\Sigma_i\ \lambda_i}$$

This of course is the conventional formula used for the average interruption duration.

5.7.2 Derivation of Analytical Formula for Annual Interruption Time Distribution

Unlike for the interruption duration, obtaining a general formula for the annual interruption time distribution is not a simple matter. The main difficulty stems from the fact that the total interruption time in a year may result from a number of failures of separate components. Both the joint probability density function for a component failing more than once in the same year and the joint density function for separate components all failing in the same year are involved. A formula for the density function of the annual interruption time is derived below for a load point where three components contribute to the interruption time.

The same qualifying assumptions are made as for the interruption duration distribution.

Let u_i = hours of interruption to the load point of interest in that given year due to component i

f_i = number of failures of component i in the given year

${}_jR_i$ = duration of interruption J of component i

For a three component system (i=1, 2, & 3) in any given year:

$P[U_s = u]$ = probability that the annual interruption time equals u hours per year

$$= P[U_1=u] \cdot P[f_2,f_3=0] + P[U_2=u] \cdot P[f_1,f_3=0] + P[U_3=u] \cdot P[f_1,f_2=0]$$
$$+ P[U_1+U_2=u] \cdot P[f_3=0] + P[U_1+U_3=u] \cdot P[f_2=0] + P[U_2+U_3=u] \cdot P[f_1=0]$$
$$+ P[U_1+U_2+U_3=u] \quad (5\text{-}9)$$

For the special care of $U_s = 0$,

$$P[U_s=0] = P[U_s=0 \mid f_1+f_2+f_3 \neq 0]\, P[f_1+f_2+f_3 \neq 0] + P[f_1,f_2,f_3 = 0] \quad (5\text{-}10)$$

where the first term on the R.H.S. is calculated by the earlier formula Eq. (5-9). Of course in a real system, if U=0, then by definition no interruption has occurred and only the second term of Eq. (5-10) applies.

Considering the first three terms on the RHS of Eq. (5-9):

$$P[U_1=u] = P[f_1=1]\, P[R_1=u] + P[f_1=2]\, P[{}_1R_1+{}_2R_1=u] + \ldots + P[f_1=n]\, P[{}_1R_1+{}_2R_1+\ldots{}_nR_1=u] \quad (5\text{-}11)$$

where n is some sufficiently large integer. Similarily for $P[U_2=u]$ and $P[U_3=u]$.

Considering the fourth, fifth and sixth terms on RHS of Eq. (5-9):

$$P[U_1+U_2=u] = P[f_1=1]\, P[f_2=1]\, P[{}_1R_1+{}_1R_2= u] +$$
$$P[f_1=2]\, P[f_2=1]\, P[{}_1R_1+{}_2R_1+{}_1R_2 = u] +$$
$$P[f_1=1]\, P[f_2=2]\, P[{}_1R_1+{}_1R_2+{}_2R_2 = u] + \quad \ldots. +$$
$$P[f_1=n]\, P[f_2=n]\, P[{}_1R_1+\ldots+ {}_nR_1+{}_1R_2+\ldots+{}_nR_2 = u] \quad (5\text{-}12)$$

similarly for $P[u_2+u_3 = u]$ and $P[u_1+u_3 = u]$

Considering the last term on the RHS of Eq. (5-9):

$$P[u_1+u_2+u_3 = u] = P[f_1=1]\, P[f_2=1]\, P[f_3=1]\, P[{}_1R_1+{}_1R_2+{}_1R_3=u] + P[f_1=2]\, P[f_2=1]\, P[f_3=1]\, P[{}_1R_1+{}_2R_1+{}_1R_2+{}_1R_3=u] + \ldots +$$

$$P[f_1=n]\, P[f_2=n]\, P'f_3=n]\, P[{}_1R_1+\ldots+{}_nR_1+{}_1R_2+\ldots+{}_nR_2+{}_1R_3+\ldots+{}_nR_3=u] \quad (5\text{-}13)$$

where n = the maximum number of interruptions in a year.

Evaluation of the terms of Eq. (5-11, 5-12), and (5-13):

$$P[f_i=m] = \frac{(\lambda t)^m e^{\lambda t}}{m!}$$ (assuming a Poisson failure rate, $t = 1$ year, $\lambda = \lambda_i$) (5-14)

$P[R_i=u]$ can be found from the probability density function of $R(r)$.

Since a program to generate the reliability indices and their distributions must deal with intervals of r or u and not the whole continuim, equations for the interval probabilities are given next.

$P[u_1 < R_i \leq u_2]$ = Probability that R_i is equal to a duration in the interval from u_1 up to and including u_2.

$$P[u_1 < R_i \leq U_2] = \frac{1}{r}\int_{U_1}^{U_2} e^{-\frac{1}{r}t}\, dt = e^{\frac{-U_1}{r}} - e^{\frac{-U_2}{r}} \quad (5\text{-}15)$$

where an exponential restoration activity is assumed and r = mttr

If the restoration activity is assumed to have a log-normal distribution the interval probabilities are given by:

$$P[U_1 < R_i \leq U_2] = \int_{U_1}^{U_2} f_R(r)\, dr$$

$$= F_R(U_2) - F_R(U_1) \quad (5\text{-}16)$$

where: $$F_R(r) = \frac{1}{\sqrt{2\pi}} \int_{-\infty}^{\frac{\ln(r)-m}{\sigma}} e^{\frac{-x^2}{2}}\, dx$$

(5-17)

which is the standard normal probability integral form of the log-normal cumulative distribution function.

m and σ are the parameters of the related normal distribution. The mttr = $e^{m + \sigma^2/2}$ and the variance of the restoration distribution = $\sigma_r^2 = e^{2m + 2\sigma^2} - e^{2m + \sigma^2}$. A closed form solution for the integral of Eq. (5-16) cannot be found but the probability value from the definite integral can be obtained manually from tables or in the case of a program, the value can be obtained from available computer system library functions or subroutines. An example is the IBM built-in function ERF(X) which gives the value for the error function (88):

$$\mathrm{erf}(x) = \frac{2}{\pi} \int_0^x e^{-t^2}\, dt$$

If the restoration activity is assumed to have a gamma distribution the interval probabilities of Eq. (5-16) must be calculated from the incomplete gamma function which also has no closed form solution (89). The probabilities can be approximated by using numerical integration. Other distributions could also be assumed but for the purposes of analytically constructing the reliability index distributions, the algorithm must be such that the computer time required to obtain interval probabilities can not be unacceptably long.

The terms of Equations (4-12), (4-13), and (4-14) which involve annual times resulting from two or more failure durations are considered next. The interval probabilities will be derived. For the two failure terms, the probability associated with the area delineated in Figure 5.16 must be calculated. Equation (5-19) gives these probabilities while Equation (5-20) gives it for the log-normal case. Similar equations can be obtained for the terms involving three or more failure durations. The shaded area in Figure 5.16 is used to calculate

$P[u_1 < x+y \leq u_2]$.

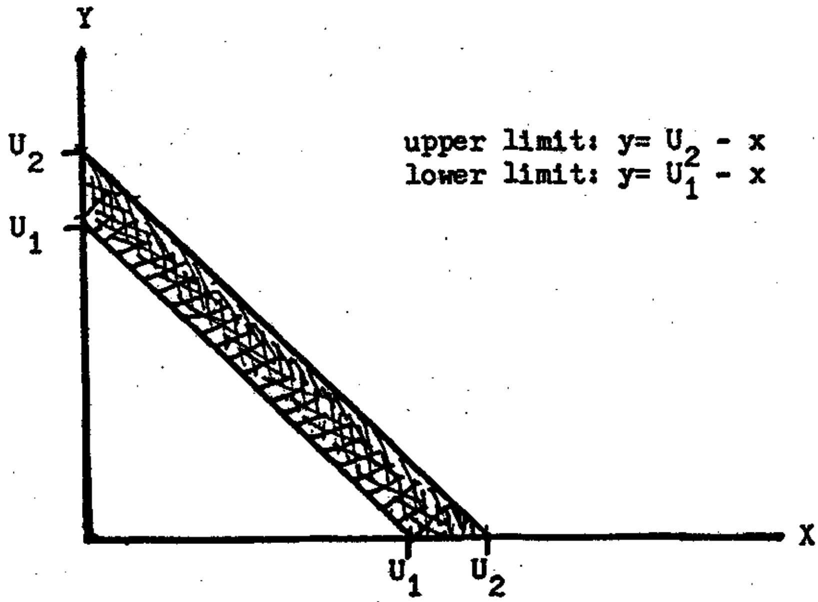


Figure 5.16: Two Failure Term Integral Area

$$fy\ (y) = \frac{1}{y\,\sigma_y\sqrt{2\pi}}\ e^{-(\log y - m_y)^2/2\sigma_y^2} \qquad y \geq 0 \tag{5-18}$$

$$fx\ (x) = \frac{1}{x\,\sigma_x\sqrt{2\pi}}\ e^{-(\log x - m_x)^2/2\sigma_x^2} \qquad X \geq 0$$

$$P[u_1 < x + y \leq u_2] = \int_{x=o}^{x=u_2}\int_{y=u_1-x}^{y=u_2-x} fx,y\ (x,y)\ dx\ dy$$

$$= \int_{x=o}^{x=u_2}\int_{y=u_1-x}^{y=u_2-x} fx(x)\ fy(y)\ dx\ dy \qquad \text{since X is independent of Y} \tag{5-19}$$

$$P[u_1<X+Y\leq U_2] = \int_{x=0}^{x=U_2}\int_{y=u_1-x}^{y=u_2-x} \frac{1}{xy\sigma_x\sigma_y 2\pi} e^{-\frac{(\log y-m_y)^2}{2\sigma_y^2} - \frac{(\log x-m_x)^2}{2\sigma_x^2}} dx\, dy \qquad (5\text{-}20)$$

Equation (5-20) and the similar integrals with more variables do not have a closed form solution. The most feasible approach in a computer program is to approximate the probabilities using numerical integration. Compared with the univariate case of Equation (5-16), these multivariate probabilities are more likely to involve excessively long computation times. However, analytical construction of the Annual Interruption Time Distribution may still be feasible if care is taken in programming to ensure that:

1) the number of integration intervals is not greater than accuracy demands
2) in Equation (5-11), (5-12) and (5-13) n, the maximum number of interruptions in a year is not greater than accuracy demands
3) as much advantage as possible is taken of redundancy in the calculations
4) efficient algorithms are used to calculate the point probabilities
5) distributions assumed for the restoration activities are ones which require only reasonable point probability calculation times.

Analytical construction of the Interruption Duration Distribution only requires the calculation of univariate interval probabilities. The required computational time is thus not long and is not an obstacle to the use of a construction program.

5.7.3 Example of Analytical Construction of Load Point Outage Duration

The sample system used in this example is the same one used earlier and is depicted in Figure 4.1. The calculations giving the average values for the load point indices are repeated in Table 5.11 for load points A and B. The simulation and analytical construction for the example assume all times exponentially distributed except for the repair times which have a log-normal distribution with the standard deviation equal to .5 hours. Since for each load point only four components contribute to that load points' outages; Equation (5-8) becomes:

$P[r_1 < R \leq r_2] =$

$$\frac{\lambda_1 P[r_1 \leq R_1 \leq r_2] + \lambda_2 P[r_1 \leq R_2 \leq r_2] + \lambda_3 \, P[r_1 \leq R_3 \leq r_2] + \lambda_{4 \text{ or } 5 \text{ or } 6} \, P[r_1 \leq R_{4 \text{ or } 5 \text{ or } 6} \leq r_2]}{\lambda_s}$$

Table 5.11 Calculation of Indices for the Sample System - Case 1

Component		Load Point A			Load Point B	
	λ f/yr	r hrs	λr hrs/yr	λ f/yr	r hrs	λr hrs/yr
Primary Main						
Component 1 2m section	.2	3.0	.6	.2	3.0	.6
Component 2 3m section	.3	.5	.15	.3	3.0	.9
Component 3 1m section	.1	.5	.05	.1	.5	.05
Primary Lateral						
Component 4 3m section	.75	1.0	.75	--	--	--
Component 5 2m section	--	--	--	.50	1.0	.5
Component 6 1m section	--	--	--	--	--	--
	1.35	1.15	1.55	1.1	1.86	2.05

	Load Point A	Load Point B
λ - failures/year	1.35	1.10
r - hours/failure	1.15	1.86
u - hours/year	1.55	2.05

As in Equation (5-15) the exponential terms become:

$$P[r_1 < R \leq r_2] = e^{-\frac{r_1}{m}} - e^{-\frac{r_2}{m}}$$

where m = mean-time-to-restoration for the manual sectionalizing activities

As in Equation (5-17) the lognormal terms become

$$P[r_1 < R \leq r_2] = \frac{1}{\sqrt{2\pi}} \int_{-\infty}^{\frac{\ln(r_2)-m_x}{\sigma_x}} e^{-t^2/2}\, dt - \frac{1}{\sqrt{2\pi}} \int_{-\infty}^{\frac{\ln(r_1)-m_x}{\sigma_x}} e^{-t^2/2}\, dt \qquad (5\text{-}21)$$

where:

$$\sigma_x = \sqrt{\ln(\sigma^2 + m^2) - \ln(m^2)}$$

$$m_x = \ln(m) - \frac{\sigma_x^2}{2}$$

m = mttr of lognormal repair

σ = standard deviation of lognormal repair

Equation (5-21) can be computed by calculating

$$X = \frac{\ln(r) - m}{\sigma}$$

and finding Q(X) where Q is the standard normal probability integral.

Tables 5.12 and 5.13 show the resulting calculations for the first seventeen intervals of interruption duration for load points A and B of case 1. The tables also compare the probabilities calculated from the construction equations with the probabilities calculated from the simulation program histogram frequencies. The probabilities are in close agreement. The small differences can be attributed to random error inherent in a probalistic simulation and to the inability of random variate generators to generate perfect sets of variates (83).

Note that in this example, only three distributions are needed although there are four components for each load point. Components with identical distributions are combined by aggregating their respective weighting factors. For example: in the case of load point A outages of both components 2 and 3 result in manual sectionalizing times with means of .5 hrs. and are exponentially distributed. The weighting factor become:

$$\lambda / \lambda_s = \frac{\lambda_2 + \lambda_3}{\lambda_s}$$

The parameter values for the calculations are:

Load Point A

Component 1 $m_1 = 3.0$ hrs $\sigma_1 = .5$ hrs lognormal repair

$$\sigma_{x1} = \sqrt{\ln(.5^2 + 3^2) - \ln(3^2)}$$

$$= .1655 \text{ hrs}$$

$$m_{x1} = \ln(3) - \frac{(.1655)^2}{2}$$

$$= 1.0849 \text{ hrs}$$

Component 2 $m_2 = .5$ hrs exponential sectionalizing time

Component 3 $m_3 = 1.0$ hrs $\sigma_3 = .5$ hrs lognormal repair

$$\sigma_{x3} = .4724$$

$$m_{x3} = -.1116$$

Load Point B

Component 1 $m_1 = 3.0$ hrs $\sigma_1 = .5$ hrs lognormal repair
$\sigma x_1 = .1655$ hrs
$mx_1 = 1.0849$ hrs

Component 2 $m_2 = 3.0$ hrs $\sigma_2 = .5$ hrs lognormal repair
$\sigma x_2 = .1655$ hrs
$mx_2 = 1.0849$ hrs

Component 3 $m_3 = 1$ hour $\sigma_3 = .17$ hrs lognormal repair
$\sigma x_3 = .1688$ hrs
$mx3 = -.0142$ hrs

Table 5.12 Interval Probabilities of Load Point A Outage Durations - Case 1, Lognormal Repair

Interruption Duration (Hours)	0–.3	.3–.6	.6–.9	.9–1.2	1.2–1.5	1.5–1.8	1.8–2.1	2.1–2.4	2.4–2.7	2.7–3.0	3.0–3.3	3.3–3.6	3.6–3.9	3.9–4.2	4.2–4.5	4.5–4.8	4.8–5.1
Distribution 1	.0000	.0000	.0000	.0000	.0000	.0013	.0178	.0837	.1870	.2431	.2120	.1369	.0705	.0305	.0115	.0039	.0012
Distribution 2	.4512	.2476	.1359	.0746	.0409	.0225	.0123	.0068	.0037	.0020	.0011	.0006	.0003	.0002	.0001	.0001	.0000
Distribution 3	.0104	.1886	.3062	.2278	.1301	.0675	.0340	.0171	.0087	.0045	.0023	.0013	.0007	.0004	.0002	.0001	.0001
Constructed Load Point Probabilities	.1395	.1782	.2104	.1487	.0844	.0443	.0252	.0239	.0336	.0391	.0330	.0212	.0109	.0048	.0019	.0007	.0002
Simulation Probabilities	.1370	.1811	.2138	.1362	.0809	.0465	.0274	.0248	.0336	.0449	.0228	.0251	.0128	.0037	.0022	.0009	.0001
Simulation Frequencies	921	1218	1438	916	544	313	184	167	226	302	194	169	86	25	15	6	1

Distribution 1: lognormal repair, mttr - 3.0 hrs., S.D. = .5 hrs.

$$\lambda / \lambda_s = \lambda_1 / \lambda_s = .2/1.35 = .1481$$

Distribution 2: exponential manual sectionalizing, m = .5 hrs.

$$\lambda / \lambda_s = (\lambda_2 + \lambda_3)/\lambda_s = (.3 + .1)/1.35 = .2963$$

Distribution 3: lognormal repair, mttr = 1.0 hrs, S.D. = .5 hrs.

$$\lambda / \lambda_s = \lambda_4 / \lambda_s = .75/1.35 = .5556$$

Table 5.13 Interval Probabilities of Load Point B Outage Durations - Case 1, Lognormal Repair

Interruption Duration (Hours)	0 – .3	.3 – .6	.6 – .9	.9 – 1.2	1.2 – 1.5	1.5 – 1.8	1.8 – 2.1	2.1 – 2.4	2.4 – 2.7	2.7 – 3.0	3.0 – 3.3	3.3 – 3.6	3.6 – 3.9	3.9 – 4.2	4.2 – 4.5	4.5 – 4.8	4.8 – 5.1
Distribution 1	.0000	.0000	.0000	.0000	.0000	.0013	.0178	.0837	.1870	.2431	.2120	.1369	.0705	.0305	.0115	.0039	.0012
Distribution 2	.4512	.2476	.1359	.0746	.0409	.0225	.0123	.0068	.0037	.0020	.0011	.0006	.0003	.0002	.0001	.0001	.0000
Distribution 3	.0104	.1886	.3062	.2278	.1301	.0675	.0340	.0171	.0087	.0045	.0023	.0013	.0007	.0004	.0002	.0001	.0001
Constructed Load Point Probabilities	.0457	.1082	.1515	.1103	.0628	.0333	.0246	.0464	.0893	.1127	.0975	.0629	.0324	.0140	.0053	.0018	.0006
Simulation Probabilities	.0437	.1094	.1467	.1072	.0642	.0325	.0230	.0495	.0923	.1145	.0945	.0662	.0352	.0136	.0054	.0015	.0005
Simulation Frequencies	241	603	809	591	354	179	127	273	509	631	521	365	194	75	30	8	3

Distribution 1: lognormal repair, mttr - 3.0 hrs., S.D. = .5 hrs.

$$\lambda / \lambda_s = (\lambda_1 + \lambda_2)/\lambda_s = (.2 + .3)/1.1 = .4545$$

Distribution 2: exponential manual sectionalizing, m = .5 hrs.

$$\lambda / \lambda_s = \lambda_3/\lambda_s = .1/1.1 = .0909$$

Distribution 3: lognormal repair, mttr = 1.0 hrs, S.D. = .5 hrs.

$$\lambda / \lambda_s = \lambda_5/\lambda_s = .5/1.1 = .4545$$

The above approach can be applied to other configurations and systems such as in the example calculations of Sections 4.1 and 5.2. A complication arises in situations such as that of Load Point C, Case 3 of Section 4.1. As can be seen in Table 3.5, the 1 m primary main section and the 1 m primary lateral result in repair activities. However, both the 2 m and 3 m primary main sections result in two different possible activities: switching (average of 1 hr.) when the alternate supply has a low load and repair (average of 3 hrs.) when the alternate supply load is high. The approach of using a restoration time (average of 2 hrs.) which is a weighted average of the two activities cannot be used when the activities do not involve identical duration distributions. Instead, the respective restoration times must be maintained and the weighting factors modified by the transfer probabilities. Table 5.14 shows the calculations and gives the constructed and simulated interval probabilities.

As these calculations indicate, distributions associated with the load point outage durations can be obtained easily. For very small systems such as the example one, even a set of manual calculations can suffice. For larger systems, a computer program becomes necessary but the programming effort and computing time involved is considerably less than that for the simulation approach.

To demonstrate the ease of obtaining distributions even without ready access to a computer, a program for the TI-58 or TI-59 programmable calculator was developed. The program is capable of calculating the interval probabilities of the load point outage durations for any number of components with any mixture of exponential and lognormal

Table 5.14 Interval Probabilities of Load Point C Outage Durations - Case 1, Lognormal Repair

Interruption Duration (Hours)	0–.3	.3–.6	.6–.9	.9–1.2	1.2–1.5	1.5–1.8	1.8–2.1	2.1–2.4	2.4–2.7	2.7–3.0	3.0–3.3	3.3–3.6	3.6–3.9	3.9–4.2	4.2–4.5	4.5–4.8	4.8–5.1
Distribution 1	.0000	.0000	.0000	.0000	.0000	.0013	.0178	.0837	.1870	.2431	.2120	.1369	.0705	.0305	.0115	.0039	.0012
Distribution 2	.2592	.1920	.1422	.1054	.0781	.0578	.0428	.0317	.0235	.0174	.0129	.0096	.0071	.0052	.0039	.0029	.0021
Distribution 3	.0104	.1886	.3062	.2278	.1301	.0675	.0340	.0171	.0087	.0045	.0023	.0013	.0007	.0004	.0002	.0001	.0001
Constructed Load Point Probabilities	.0793	.1120	.1319	.0980	.0612	.0374	.0299	.0488	.0865	.1066	.0918	.0596	.0313	.0142	.0059	.0025	.0012
Simulation Probabilities	.0791	.1161	.1287	.0949	.0607	.0386	.0330	.0491	.0882	.1059	.0835	.0600	.0314	.0179	.0077	.0026	.0007
Simulation Frequencies	340	499	553	408	261	166	142	211	379	455	359	258	135	77	33	11	3

Distribution 1: lognormal repair, mttr - 3.0 hrs., S.D. = .5 hrs.

since transfer probability = .5 for 2 m and 3 m primary mains calculate partial weighting factors = $.5\lambda$

.. for Distribution 1: $\lambda/\lambda_s = \frac{.5\lambda_1 + .5\lambda_2 + \lambda_3}{.85} = .4118$

Distribution 2: exponential switching time; m = 1 hr.

$\lambda/\lambda_s = \frac{.5\lambda_1 + .5\lambda_2}{.85} = .2941$

Distribution 3: lognormal repair, mttr = 1.0 hrs, S.D. = .5 hrs.

$\lambda/\lambda_s = \lambda_4/.85 = .2941$

distributions. The operator must perform a failure modes and effect analysis as outlined in Section 4.1 and then provide the parameter values and weighting factors for each distribution. The total time to obtain the interval probabilities for one load point in the above examples was about fifteen minutes. This includes the time required by the operator to input and output data. Table 5.10 compares the calculation times of the simulation program and the TI:58/59 program. Appendix C provides the program listing and related information.

6 CONCLUSIONS

Many different approaches are available to determine user interruption cost coefficients; the most prevalent and practical ones involve gross economic activity indices (eg. GNP/KWHR) and user surveys to determine duration/user specific interruption costs (eg. $/KW). While the GNP/KWHR type data has the advantages of ease of determination and application, the $/KW survey data has the advantages of greater accuracy and validity and the ability to differentiate between user types and interruption scenarios. Much effort is being devoted to the improvement of interruption cost collection methodology and to the actual collection of data but major shortcomings still exist for application purposes:

1) theoretical basis and validity of interruption cost methodologies still not fully developed
2) much of the data already collected is not based on sound definitions and methodology
3) there is a lack of data on variation of costs with factors such as user characteristics (eg. size or geographical location) and interruption characteristics (eg. interruption duration or time of occurrence).

At present there is already available data of sufficient validity to perform useful interruption worth analyses.

Many studies have been performed on the optimization of generation system reliability by the application of interruption worth data in cost/benefit analyses. Such studies have been and continue to be limited to the consideration of generation adequacy rather than security because of the immature state of the art of security assessment. The results and conclusions of all these studies are of restricted applicability because generation adequacy indices are relative indicators not absolute measures of reliability and because presently available interruption worth data does not adequately include the indirect effects of generation type interruptions which tend to be of a large scale. Reliability indices based on the Frequency and Duration approach are more suitable for reliabilty worth assessment than the LOLE type indices.

Presently there appear to be at least three major approaches available which utilities can utilize when performing cost/benefit studies of generation reliability. Sanghvi's LOLP and linear programming optimization program performs an overall general optimization including factors such as capital, operating, and interruption costs and uncertainty of resource unavailability. It is computationally efficient but of limited dependability and validity. The Decision Focus Over/Under approach uses a somewhat more absolute prediction of reliability but does not perform an optimization of resource mix and does not adequately incorporate the effects of interruption characteristics such as frequency and duration. Poore's approach uses a more appropriate and absolute predictor of reliability and incorporates fairly adequately the factors which affect interruption cost. This approach is not presently available as part of an overall generation expansion optimization package but can readily utilize a utility's present F & D reliability program.

Few studies have been performed on the optimization of composite system reliability because composite reliability assessment itself is a still developing technique which is not yet in widespread use. Ulti-

mately the application of reliability worth to composi'
a valuable and appropriate one because the indices will be more
measures than the generation indices and because load point reliability will be evaluated as well as system reliability. The University of Saskatchewan composite reliability program "COMREL" was utilized in an example costing application and to provide indications as to the problems that can arise in practical composite reliability worth studies.

Distribution system reliability assessment results in fairly absolute measures of user reliability. The indices are amenable to combination with interruption cost data in reliability worth assessment. Reliability worth data is most applicable in distribution system studies (as compared with generation or composite studies) because the interruptions are usually local random interruptions of a small scale and do not result in large indirect costs or effects.

Package programs to perform distribution system reliability optimization do not appear to be commercially available but this is at least in part the case because such programs are relatively easy to develop by the utility users themselves and because the theoretical basis is extremely simple. The thesis discusses considerations and problems associated with applying reliability worth in distribution system studies.

One of the main problems identified is that the interruption duration indices used to evaluate interruption costs in generation, composite, and distribution studies are the average values of the particular measure of reliability. Interruption cost function nonlinearities can result in large errors if the variation of duration about the mean is ignored. A study of the probability distributions associated with distribution system interruption durations was undertaken to investigate the potential costing errors. An additional incentive to study the indice distributions is that index distributional information has many potentially valuable applications aside from interruption costing. The distributions obtained by the probabilistic simulation program for the Load Point Failure Rate, Outage Duration, and Annual Interruption Time and for the SAIDI, SAIFI, and CAIDI system performance indices are presented and discussed.

If restoration times can be assumed to be exponentially distributed, the load point outage duration can be approximated as being gamma distributed. Often restoration times can not be assumed to be exponentially distributed and in these cases the duration distribution cannot generally be represented by a gamma distribution. The distribution may be multi-modal and not describable by any known distribution. The thesis discusses variation of distribution shape with:

1) distributions underlying the restoration processes
2) distribution means (ie. index values)
3) distribution standard deviations
4) system configuration and operation
5) position in system
6) size of sections
7) size of system

The distribution system simulations were utilized to investigate the interruption cost distributions and the errors resulting from using average durations to calculate costs. The costs for twenty-three cost functions, which were choosen to represent the range of functions, indicates that while in the majority of cases the error is likely to be negligible or only moderate, in a significant number of cases the error can be quite large. Curves which are aggregates of the costs of many smaller and different user groups tend to be linear and have a small error. Curves for more specific groups of users with similar characteristics tend to have sharper break points, be more non-linear, and have larger errors. Because of user aggregation, there is likely less error involved in using only average durations when performing calculations for generation of composite reliability studies than for distribution reliability studies.

The use of a $/KWHR interruption cost coefficient form as compared with a duration specific $/KW interruption cost coefficient form is investigated. It is concluded that the $/KWHR form can result in significant errors due to the cost function nonlinearity. The duration specific $/KW form is deemed more appropriate for interruption costing especially in distribution system studies.

A major deterrent to the use of outage duration distributions in reliability studies and in interruption costing in particular is that simulation programs used to obtain the index distributions require fairly large amounts of CPU time. In the thesis, simple formulas to analytically construct the Load Point Outage Duration and Annual Interruption Time Distribution, are presented. By means of tabular examples and a calculator program it is shown that analytical construction of Load Point Outage Duration Distributions can be easy, feasible and computationally efficient.

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APPENDIX A: DISTRIBUTION SYSTEM SIMULATION PROGRAM DESCRIPTION AND FLOWCHART

The basic distribution system model this program simulates is a manual sectionalized primary main, with or without an alternate supply. Combinations of load transfer probabilities, individual switching times, solidly connected laterals, etc. are all possible by insertion of the proper data.

The program utilizes monte carlo techniques to generate failure times, repair durations, and switching times for manual sectionalizing, alternate feeders, and fuses. Exponential, lognormal, normal, and gamma distributions can be selected. Based on a given MTTF for each section, the first failure time for each element is randomly generated from an exponential distribution. The failure times are then queued, and the clock is stepped to the first failure. A restoration time for the failed section is then generated based on that section's MTTR. After the restoration, a new failure time is generated for the repaired element, and that time is returned to the queue.

After each year a record of events is kept, including the number of interruptions, number of failures, and outage durations of each section. Distributional information is plotted on histograms in the output of the program if the appropriate flag is set in the input. If a different flag is set, after each interruption the interruption costs are calculated and after each year the system performance indices calculated.

The program contains internal documentation. Including comments, the program is 1245 lines long. It is written in Fortran. Typical CPU times are listed in Table 5.10.

A generalized flow chart is shown on the following page.

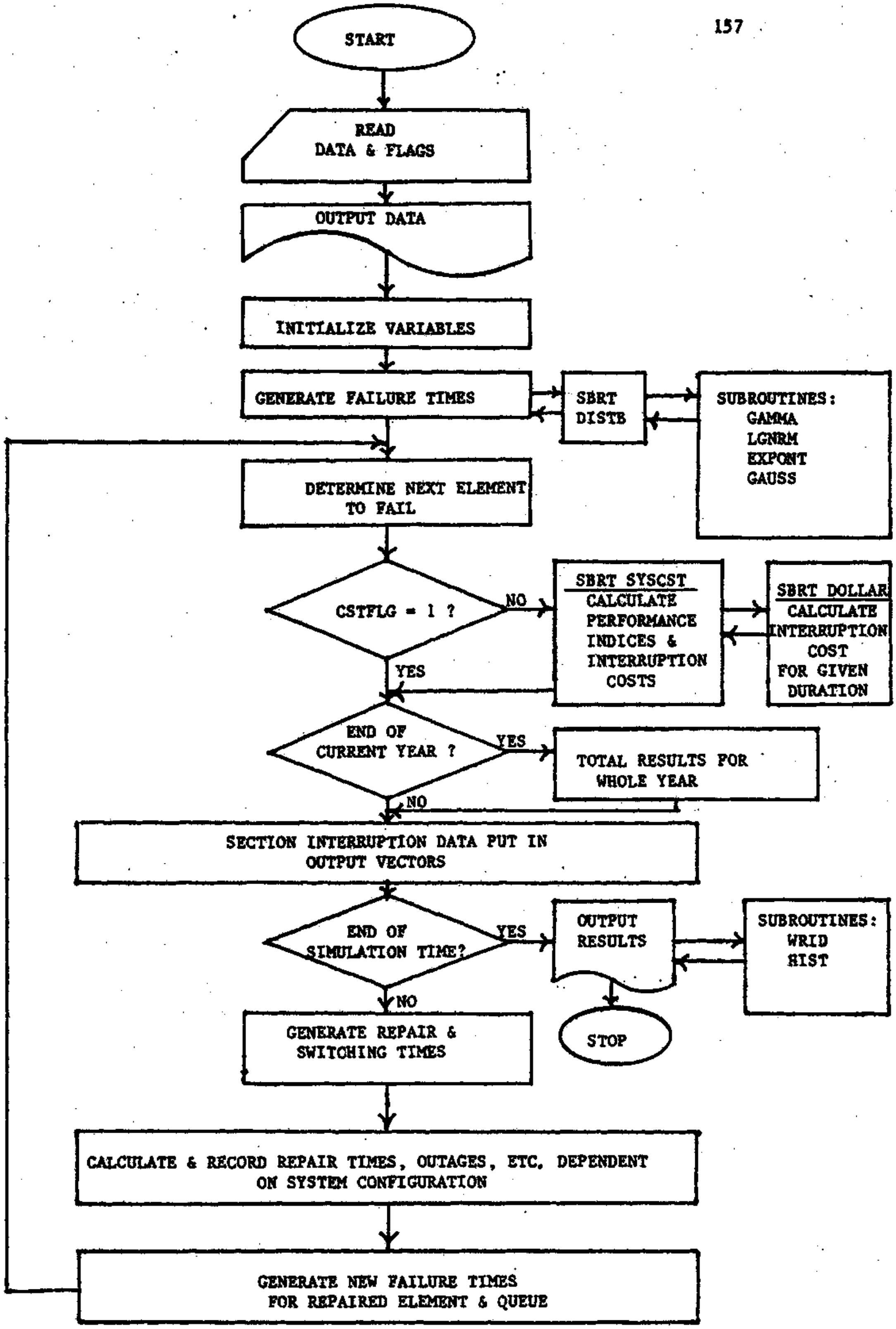


FIGURE A.1 SIMULATION PROGRAM FLOW CHART

APPENDIX B: Distributional Dependence of CAIDI

As discussed in Section 5.1, the CAIDI index average is independent of the underlying distributions when calculated for the entire simulation period. When calculated as the average of the CAIDI indices for each year, CAIDI however is dependent on the underlying distributions. The reason for this dependence is that this calculation of CAIDI consists of dividing two factors, each of which has an associated distribution. Dividing two sets of added numbers is not equivalent to adding sets of divided numbers:

eg.

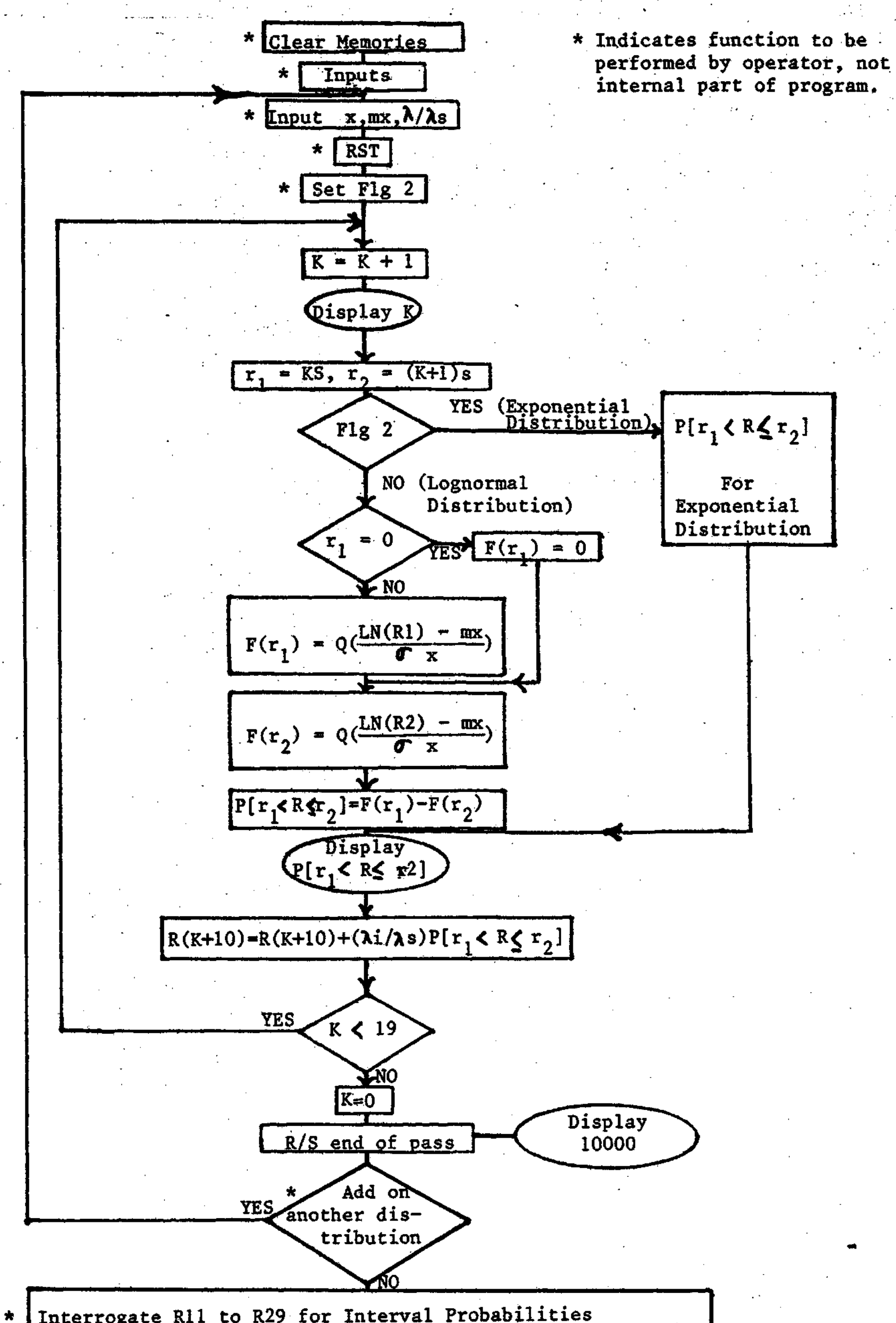
$$\frac{A + B + C}{X + Y + Z} \neq \frac{A}{X} + \frac{B}{Y} + \frac{C}{Z}$$

where: A,B,C = hours of customer interruptions

X,Y,Z = number of customer interruptions

The calculations for the "other" CAIDI, and for the SAIDI, SAIFI, and load point indices consists of dividing a set of distributed numbers by some constant and thus their averages are distributionally independent. Fortunately, for large systems, differences resulting from the two approaches to calculating CAIDI averages tend to be negligible due to the fact that variation in CAIDI from year to year is not great.

Appendix C: Analytical Construction Program Flowchart For Texas Instruments TI 58/59 Programmable Calculator



TITLE: ANALYTICAL CONSTRUCTION OF INTERRUPTION DURATION   PAGE 1 OF 3   **TI Programmable Program Record**

PROGRAMMER: Eduard Wojczynski   DATE: Sept./82

Partitioning (Op 17): 3.1.9.1.9 Default   Library Module: MASTER   Printer: ____   Cards: ____

PROGRAM DESCRIPTION

Calculates interval probabilities of exponential and/or lognormal distributions, i.e. $P[(J-1)S < t \leq JS] = \sum_{\lambda} (\lambda i/\lambda s) \int_{(J-1)S}^{JS} fi(t)dt$ where: fi(t) = probability density functions of i distributions, J = 1, 2, . . 19 intervals. In each pass: operator inputs parameters, program generates distribution probabilities, multiplies each probability by its weighting factor ($\lambda i/\lambda s$) and adds each weighted probability to the other probabilities for that interval.

USER INSTRUCTIONS

STEP	PROCEDURE	ENTER	PRESS		DISPLAY
1	Clear Memories		2nd	CMs	
2	Enter Interval Width S	S	C		S
3	Enter Standard Deviation σx	σx	D		σ
4	Enter Mean mx	mx	E		mx
5	Enter Weighting Factor ($\lambda i/\lambda s$)	$\lambda i/\lambda s$	2nd	B	$\lambda i/\lambda s$
6	Go To 0 and Clear Flags		RST		
7	If Exponential Distribution, Set Flag		2nd	STFLG 2	
8	Start Program		R/S		
9	Program Will Display Interval Numbers (K) and Probabilities in Cycles				K $P[r_K < R \leq r_{K+1}]$
10	Once All 19 Interval Probabilities are Calculated, Program Displays 10000				10000
11A	If More Components to be Added: Redo Steps 3, 4, 5, 6, 7 and 8				
11B	If No More Components to be Added: To Obtain Interval Probabilities: Interrogate Data Registers R11 to R29	Interval Numbers K N=K+10=11,12,..29	RCL		$P[r_N < R \leq r_{N+1}]$
12	To Compute Another Load Point Distribution Start Again At Step 1				

USER DEFINED KEYS

Key	Use
A	USED BY ML-14
B	USED BY ML-14
C	INTERVAL WIDTH(S)
D	σ
E	m
A'	SBR - Q(X)
B'	$\lambda i/\lambda s$
C'	
D'	
E'	

DATA REGISTERS

0	INDIRECT	0	$\lambda i/\lambda x$
1	ML-14	1	$P[0 < R \leq S]$
2	ML-14	2	$P[S < R \leq 2S]$
3	ML-14	3	$P[2S < R \leq 3S]$
4	S=INTERVAL WIDTH	4	$P[3S < R \leq 4S]$
5	m=MEAN	5	Similarly for
6	σ=STD. DEV	6	R15 to R29
7	r_2	7	
8	r_1(or P[ ])	8	
9	K=# of Intervals	9	

LABELS (Op 08)

FLAGS 0	1	2	3	4	5	6	7	8	9
ML-14	0=LGNM 1=EXP								

TITLE ANALYTICAL CONSTRUCTION OF INTERRUPTION DURATION PAGE 2 OF 3 **TI Programmable Coding Form**

PROGRAMMER Eduard Wocizynski DATE Sept./82

LOC	CODE	KEY	COMMENTS
0	43	RCL	
0	4	4	RCL S
0	42	STO	(Interval
0	7	7	Width)
0	42	STO	
0	8	8	
0	43	RCL	
0	9	9	RCL K
0	85	+	(Counter)
0	1	1	
1	95	=	K+1
1	42	STO	
1	9	9	
1	66	Pause	Display K+1
1	49	PRD	
1	7	7	r_2=(K+1)S
1	75	-	
1	1	1	
1	95	=	K
1	49	PRD	
2	8	8	
2	43	RCL	
2	8	8	r_1=KS
2	95	=	
2	87	IF FLG	IF EXP.
2	2	2	Distn.
2	24	CE	GO TO CE
2	32	x≷t	
2	0	0	
2	95	=	
3	22	INV	IF(=0)
3	67	x=t	F(1)=1.0
3	38	SIN	
3	1	1	
3	95	=	
3	61	GTO	
3	39	COS	
3	76	LBL	
3	38	SIN	
3	32	x≷t	
4	23	LN	LN (r_1)
4	42	STO	
4	8	8	
4	43	RCL	
4	5	5	$\frac{LN(r_1)-mx}{\sigma x}$
4	22	INV	
4	44	SUM	
4	8	8	
4	43	RCL	
4	6	6	
5	22	INV	
5	49	PRD	
5	8	8	
5	43	RCL	
5	8	8	

LOC	CODE	KEY	COMMENTS
5	16	A'	F(r_1)
5	76	LBL	
5	39	COS	
5	42	STO	
5	8	8	Stores Q(r_1)
6	43	RCL	
6	51	7	r_2
6	23	LN	LN(r_2)
6	42	STO	
6	7	7	
6	43	RCL	
6	5	5	
6	22	INV	
6	44	SUM	
6	7	7	
7	43	RCL	
7	6	6	$\frac{LN(r_2)-Mx}{\sigma x}$
7	22	INV	
7	49	PRD	
7	7	7	
7	43	RCL	
7	7	7	
7	16	A'	F(r_2)
7	22	INV	
7	44	SUM	
8	8	8	P[r_1 ≤R≤ r_2]
8	43	RCL	
8	8	8	F(r_1)-F(r_2)
8	76	LBL	
8	29	CP	
8	66	Pause	Display
8	66	Pause	
8	66	Pause	P[1 ≤R≤ 2]
8	66	Pause	
8	43	RCL	
9	10	10	
9	95	=	λ/λs
9	49	PRD	
9	8	8	(λ/λs)(P[ ])
9	43	RCL	
9	9	9	K
9	85	+	
9	5	5	
9	85	+	
9	5	5	
10	95	=	K+10
10	42	STO	
10	0	0	R0=K+10
10	43	RCL	
10	8	8	P[ ]
10	74	SUM IND	
10	0	0	R(K+10)=
10	0	0	R(K+10)+P[ ]
10	4	4	
10	65	X	

LOC	CODE	KEY	COMMENTS
11	5	5	
11	75	-	
11	1	1	
11	75	=	
11	32	x≷t	t=19
11	43	RCL	
11	9	9	K
11	22	INV	
11	77	x≥t	IF(K<19)
11	0	0	GO TO 0
12	0	0	
12	0	0	
12	95	=	
12	42	STO	
12	9	9	K=0
12	5	5	
12	85	+	10000
12	5	5	Indicating
12	95	=	End of
12	33	x^2	Run for
13	33	x^2	that
13	91	R/S	Distribution
13	76	LBL	
13	13	C	Stores
13	42	STO	Interval
13	4	4	Width
13	91	R/S	
13	76	LBL	Stores
13	15	E	mx
13	42	STO	
14	5	5	
14	91	R/S	
14	76	LBL	
14	14	D	Stores
14	42	STO	σx
14	6	6	
14	91	R/S	
14	76	LBL	
14	17	B'	Stores
14	42	STO	λ/λs
15	10	E'	
15	91	R/S	
15	76	LBL	
15	16	A'	SBR
15	36	PGM	To
15	14	14	Calculate
15	11	A	
15	36	PGM	Q(X)
15	14	14	
15	12	B	

MERGED CODES

TEXAS INSTRUMENTS INCORPORATED

TITLE ANALYTICAL CONSTRUCTION OF INTERRUPTION DURATION PAGE 3 OF 3

PROGRAMMER Eduard Wojczynski DATE Sept./82

TI Programmable Coding Form

LOC	CODE	KEY	COMMENTS
16	92	INV SBR	
16	76	LBL	
16	24	CE	
16	42	STO	
16	8	8	
16	43	RCL	
16	5	5	
16	35	1/x	
16	95	=	SBR
16	94	+/-	To
17	49	PRD	Calculate
17	8	8	
17	49	PRD	$P[r_1 \leq R \leq r_2]$
17	7	7	
17	43	RCL	For
17	8	8	Exponential
17	22	INV	R
17	23	LN	
17	42	STO	
17	8	8	
18	43	RCL	
18	7	7	
18	22	INV	
18	23	LN	
18	22	INV	
18	44	SUM	
18	8	8	
18	43	RCL	
18	8	8	
18	61	GTO	
19	29	CP	